WINS: Market Simulation Tool for Facilitating Wind Energy Integration

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List of Acronyms

AC	Alternating Current
AEP	Annual Energy Production
AGC	Automatic Generation Control
AWC	Atlantic Wind Connection
CF	Capacity Factor
CO ₂	Carbon Dioxide
COE	Cost of energy
ComEd	Commonwealth Edison
CSC	Current Source Converter
DB	Database
DC	Direct Current
DOE	Department of Energy
ECE	Electrical and Computer Engineering
ECEDHA	Electrical and Computer Engineering Department Heads Association
EMS	Energy Management System
EPRI	Electric Power Research Institute
FERC	Federal Energy Regulatory Commission
GE	General Electric
GENCO	Generation Company
GIS	Geographical Information System
GUI	Graphical User Interface
GW	giga-watt
GWh	giga-watt-hour
I/O	Input/Output
IEC	International Electrotechnical Commission
IEEE	The Institute of Electrical and Electronics Engineers
IIT	Illinois Institute of Technology
IPPSC	Intelligent Perfect Power System Controller
IPRO	Interprofessional Project
IPS	Intelligent Power Solutions, LLC
ISO	Independent System Operator
IT	Information Technology
kV	kilo-volt
kW	kilo-watt
kWh	kilo-watt-hour
LMP	Locational Marginal Price
LWS	Laser Wind Sensor
MB	mega-byte
MISO	Midwest Independent System Operator

MMS	Market Management System
MTEP	MISO Transmission Expansion Planning
MW	mega-watt
MWh	mega-watt-hour
NERC	North American Electric Reliability Corporation
NETCS	National Electric Transmission Congestion Study
NREL	National Renewable Energy Laboratory
OEM	Original Equipment Manufacturer
OTS	Office of Technical Services
PHEV	Plug-in Hybrid Electric Vehicle
PI	Principal Investigator
PJM	Pennsylvania-New Jersey-Maryland
PMU	Phasor Measurement Units
POMS	POwer Market Simulator
PV	Photovoltaic
SCADA	Supervisory Control and Data Acquisition System
SCUC	Security-Constrained Unit Commitment
SQL	Structured Query Language
SR	Switched Reluctance
TSR	Tip Speed Ratio
TW	terra-watt
TWh	terra-watt-hour
USB	Universal Serial Bus
V2G	Vehicle to Grid
VAR	Volt-Amp-Reactive
VLAN	Virtual Local Area Network
VPN	Virtual Private Network
VPPC	Vehicle Power and Propulsion Conference
VSC	Voltage Source Converter
WECS	Wind Energy Conversion Systems
WFMS	Wind Farm Management System
WG	Wind Generation
WINS	Wind INtegration Simulator
WISER	IIT Wanger Institute for Sustainable Energy Research
WPP	Wind Power Plants
WTC	Wind Turbine Contract
WTG	Wind Turbine Generator
WTGU	Wind Turbine Generating Unit
XML	Extensible Markup Language

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Executive Summary

Integrating 20% or more wind energy into the system and transmitting large sums of wind energy over long distances will require a decision making capability that can handle very large scale power systems with tens of thousands of buses and lines. There is a need to explore innovative analytical and implementation solutions for continuing reliable operations with the most economical integration of additional wind energy in power systems. A number of wind integration solution paths involve the adoption of new operating policies, dynamic scheduling of wind power across interties, pooling integration services, and adopting new transmission scheduling practices. Such practices can be examined by the decision tool developed by this project.

This project developed a very efficient decision tool called Wind INtegration Simulator (WINS) and applied WINS to facilitate wind energy integration studies. WINS focused on augmenting the existing power utility capabilities to support collaborative planning, analysis, and wind integration project implementations. WINS also had the capability of simulating energy storage facilities so that feasibility studies of integrated wind energy system applications can be performed for systems with high wind energy penetrations. The development of WINS represents a major expansion of a very efficient decision tool called POwer Market Simulator (POMS), which was developed by IIT and has been used extensively for power system studies for decades. Specifically, WINS provides the following superiorities:

- An integrated framework is included in WINS for the comprehensive modeling of DC transmission configurations, including mono-pole, bi-pole, tri-pole, back-to-back, and multi-terminal connection, as well as AC/DC converter models including current source converters (CSC) and voltage source converters (VSC).
- An existing shortcoming of traditional decision tools for wind integration is the limited availability of user interface, i.e., decision results are often text-based demonstrations. WINS includes a powerful visualization tool and user interface capability for transmission analyses, planning, and assessment, which will be of great interest to power market participants, power system planners and operators, and state and federal regulatory entities.
- WINS can handle extended transmission models for wind integration studies. WINS models include limitations on transmission flow as well as bus voltage for analyzing power system states. The existing decision tools often consider transmission flow constraints (dc power flow) alone which could result in the over-utilization of existing resources when analyzing wind integration.

WINS can be used to assist power market participants including transmission companies, independent system operators, power system operators in vertically integrated utilities, wind energy developers, and regulatory agencies to analyze economics, security, and reliability of various options for wind integration including transmission upgrades and the planning of new transmission facilities. WINS can also be used by industry for the offline training of reliability and operation personnel when analyzing wind integration uncertainties, identifying critical spots in power system operation, analyzing power system

vulnerabilities, and providing credible decisions for examining operation and planning options for wind integration.

This proposed project was a coordinated effort by an expert team of university and industry personnel including university participants from Illinois Institute of Technology (IIT), industry participants from McCoy Energy Consulting, Wiedman Power System Consulting, Acciona Energy, and the National Renewable Energy Laboratory (NREL). The project team was supported by industry consultants from Exelon/ComEd, the ISO New England, Southern California Edison, and British Columbia Transmission Corporation. The university participants developed the WINS with a strong support of industry participants and NREL scientists. The industry consultants further contributed to this project by ensuring the technology relevance, verifying the proposed model and the results, and enhancing the proposed solutions based on their extensive experience with ongoing wind energy developments.

Researches in this project on wind integration included (1) Development of WINS; (2) Transmission Congestion Analysis in the Eastern Interconnection; (3) Analysis of 2030 Large-Scale Wind Energy Integration in the Eastern Interconnection; (4) Large-scale Analysis of 2018 Wind Energy Integration in the Eastern U.S. Interconnection. The research resulted in **33 papers, 9 presentations, 9 PhD degrees, 4 MS degrees, and 7 awards**. Specifically,

- WINS simulates the actual market operations which is based on the security-constrained unit commitment (SCUC) with full AC transmission and voltage constraints considered. The computational engine of WINS is written in Microsoft Visual C++, and the web-based Graphical User Interface (GUI) is written in Microsoft Visual C# and ASP.NET. The database is based on ORACLE and can be extended to include other database formats as well. Microsoft Excel is used for the downloading reports. The input WINS data include (1) generation data (unit type, capacity, availability; cost information; unit operating constraints such as max/min capacities, ramping up/down rates, min on/off times, maximum number of start-ups); (2) wind data (8760 hourly profile); (3) transmission data (network topology, line parameters, control transformers, normal/contingency limits for line flows and bus voltages); and (4) load data (hourly load and distribution, demand bids and load shedding cost and data).
- A methodology based on the security-constrained unit commitment (SCUC) is applied to analyze the transmission congestion in the Eastern Interconnection of the United States for 2008 and 2018. The proposed SCUC tool for this study is referred to as the POver Market Simulator (POMS). The identified congestions are visualized along with the Geographical Information System (GIS) data and compared with the results published by the U.S. Department of Energy's National Electric Transmission Congestion Study (NETCS) in 2006. The POMS study also provides the locational marginal price (LMP) information in the Eastern Interconnection, which is not available in the NETCS report. The POMS simulation results for representing congested branches and LMPs could be applied to the future transmission expansion planning studies.
- A comprehensive large-scale wind energy integration analysis is considered which is based on the 2030 load forecast in the Eastern Interconnection of the United States. This study is

performed using WINS. In this study, transmission constraints are not considered when studying the wind energy portfolios. The wind energy integration is studied based on the capacity factors of potential wind sites. Wind energy contributions to peak/off-peak annual production costs are studied based on the WINS simulation results. The sensitivity of fuel costs, wind energy production, hourly loads, carbon costs, and load management are analyzed in the wind energy integration Scenarios. The results of the study suggest that large-scale wind energy integration will have a major impact on the hourly commitment and dispatch of gas and coal units, especially at off-peak load hours. While fuel price alterations will have major impacts on the system production cost, load variation will have a larger impact and potential carbon costs will have the greatest impact.

- A comprehensive large-scale wind energy integration analysis is implemented based on the 2018 load forecast in the Eastern Interconnection of the United States. This study is performed using WINS. The wind energy integration with/without transmission constraints are studied and analyzed. The sensitivity of fuel price, wind energy production, load, carbon cost, and load shedding are implemented to study the impact of volatility of major parameters on the WINS simulation results. 19 Scenarios are studied and analyzed. The main observations based on the simulations are listed as follows: (1) Production cost is more sensitive to transmission constraints than to wind energy integration; (2) The location of wind energy integration could have an impact on the wind energy dispatch in the hourly generation portfolio; (3) The addition of wind generation units at certain locations in the Eastern Interconnection may cause additional transmission congestion; (4) In 2018, the replacement of coal units by wind energy at certain locations could mitigate transmission congestion; (5) Wind energy is often available and can replace fossil energy at off-peak load hours. During certain seasons when wind is unavailable, wind energy supply could be replaced by fossil energy; (6) In 2018, wind energy is transmitted mostly at 500kV, 345kV, and 230kV transmission levels while the 765kV transmission is utilized less by wind generation units; (7) Higher costs for gas and oil will result in additional transmission congestion as power systems try to use cheaper coal units located centrally in fewer geographical spots. Such limited utilizations of centrally located resources may also limit the available dispatch of wind generating units; (8) Higher levels of wind energy integration could result in higher levelized congestion costs when wind generation units, located at few geographical spots, try to supply a significant level of load; (9) Carbon cost demonstrates the highest impact on the 2018 simulation results. Higher carbon costs will be instrumental in mitigating the regional transmission congestion in the Eastern Interconnection; (10) Load forecast uncertainty will have a larger impact on the 2018 simulation results as compared to fluctuations in fuel prices or possible levels of wind energy integration; (11) The levelized congestion cost may not increase monotonically with higher levels of bus loads; (12) Peak load shaving will have a major impact on the commitment and dispatch of gas units because peak loads are mostly supplied by such units. The WINS simulation results shows that lowering the hourly volatility of load profile by introducing smart grid, additional distribution automation for the utilization of demand response, and the large-scale integration of wind energy and storage

could lower the transmission congestion and improve the economics and the optimal operation of power systems in the Eastern Interconnection of the United States.

The education activities in this project on wind energy included (1) Wind Energy Training Facility Development; (2) Wind Energy Course Development. Specifically,

- To fulfill the mission on workforce training and education, the Consortium erected a permanent facility at IIT for Workforce Training and Education on Sustainable Energy and Smart Grid. IIT secured funds from the State of Illinois to renovate the 16,000 sqft of space for establishing the facility. This project provided funds to furnish the facility with the state-of-the-art equipment to offer a world-class training and education on sustainable energy at IIT. The facility has provided and will continue to provide training on sustainable energy to various sectors including power industry employees, union workers, high school teachers, the public, and students through instructor-led and internet-based training courses.
- Graduate Courses in Wind Energy were developed and offered at IIT. The course “Elements of Sustainable Energy” covers cross-disciplinary subjects on sustainable energy that relate to energy generation, transmission, distribution, and delivery as well as theories, technologies, design, policies, and integration of sustainable energy. Topics include wind energy, solar energy, biomass, hydro, nuclear energy, and ocean energy. Focus was on the integration of sustainable energy into the electric power grid, the impact of sustainable energy on electricity market operation, and the environmental impact of sustainable energy. The course “Elements of Smart Grid” at IIT covers cross-disciplinary subjects on smart grid that relates to energy generation, transmission, distribution, and delivery as well as theories, technologies, design, policies, and implementation of smart grid. Topics include: smart sensing, communication, and control in energy systems; advanced metering infrastructure; energy management in buildings and home automation; smart grid applications to plug-in vehicles and low-carbon transportation alternatives; cyber and physical security systems; microgrids and distributed energy resources; demand response and real-time pricing; and intelligent and outage management systems.
- A Short Course on “Wind Energy Technology, Interconnection and Integration” was developed to provide an introduction to the underlying technology of wind turbine generators and wind power plants, how they are modeled for power system analysis purposes for planning and operating studies, and an introduction to using actual models in simulation programs. This course is targeted towards power systems engineering and management personnel from utilities, RTOs, ISOs, and ITCs as well as consultants, manufacturers and developers involved with the evaluation and planning of the interconnection and operation of new wind plants. The students and professors who are working in the field of wind energy and technology will also benefit from this study course.

1. Introduction

The Illinois Institute of Technology (IIT) was awarded by the U.S. Department of Energy to develop a very efficient decision tool called Wind INtegration Simulator (WINS) and apply WINS to facilitate wind energy integration studies. The project started in November 2009 and ended in August 2012. The Principle Investigator of this project is Dr. Mohammad Shahidehpour, Director of the Robert W. Galvin Center for Electricity Innovation at IIT. The Project Team Members (in Alphabetical Order) include Acciona Wind Energy USA, McCoy Energy, National Renewable Energy Laboratory, Wiedman Power System Consulting.

Project Objectives. The overall objective of the proposed work is to develop a decision tool for facilitating wind energy integration. The proposed decision tool is referred to as the Wind INtegration Simulator (WINS) that can facilitate the analyses for the integration of 20% or more wind energy. WINS explores innovative solutions for offering a reliable operation of existing grid with the most economic integration of additional wind energy. WINS offers the dynamic scheduling of wind power across interties and utilizes new transmission lines for wind integration. WINS represents advanced features for the modeling and simulation of energy storage, DC transmission lines, hourly wind availability and system reserves, transmission utilization and congestion studies, optimal production costing and nodal price calculations, advanced visualization techniques for representing the hourly results, and facilitates operator training for wind integration. WINS will represent a major expansion of a very efficient decision tool called POver Market Simulator (POMS), developed by the Recipient, which has been used extensively for power system studies for decades. WINS will focus on augmenting the existing power utility capabilities to support collaborative planning analyses in the implementation of wind integration. The proposed work will be completed in three phases within two years.

Project Scope. This project is to develop a decision tool for facilitating the wind energy integration. Integrating 20% or more wind energy into the system and transmitting large sums of wind energy over long distances would require an advanced decision making capability for incorporating emerging wind energy integration techniques in large-scale power systems. The project team, consisting of power utility companies, ISOs, transmission developers, wind developers, independent consultants, national laboratories, and academic researchers, will develop a wind integration simulator and apply the tool to wind energy integration studies. The project team will engage in a three-phase research, development and demonstration project: Phase I – Develop WINS for wind integration analyses by a major expansion of the existing features of POMS and the implementation of new modeling features including wind-storage coordination, DC transmission modeling, hourly-load and wind forecast correlation, and the development of a visualization module. Phase II – Apply WINS to test a variety of industry-fed wind integration scenarios for deliverability study, nodal price study, and transmission usage and congestion study. Phase III – Disseminate the results of the proposed work via industry seminars, new course offerings, and technical paper publications.

Summary of Project Activities. During the two-year project period since November 1, 2009, the project team has engaged in the development of WINS and applied it to several congestion and wind integration

studies. In summary, researches in this project on wind integration include (1) Development of WINS; (2) Transmission Congestion Analysis in the Eastern Interconnection; (3) Analysis of 2030 Large-Scale Wind Energy Integration in the Eastern Interconnection; (4) Large-scale Analysis of 2018 Wind Energy Integration in the Eastern U.S. Interconnection; (5) Integration of Non-dispatchable Resources in Electricity Markets. The education activities in this project on wind energy include (1) Wind Energy Training Facility Development; (2) Wind Energy Course Development.

2. Background

Integrating 20% or more wind energy into the system and transmitting large sums of wind energy over long distances will require a decision making capability that can handle very large scale power systems with tens of thousands of buses and lines. There is a need to explore innovative analytical and implementation solutions for continuing reliable operations with the most economical integration of additional wind energy in power systems. A number of wind integration solution paths involve the adoption of new operating policies, dynamic scheduling of wind power across interties, pooling integration services, and adopting new transmission scheduling practices. Such practices can be examined by the proposed decision tool.

Objectives: This proposal aims at developing a very efficient decision tool called Wind INtegration Simulator (WINS) and applying WINS to facilitate wind energy integration studies. WINS will focus on augmenting the existing power utility capabilities to support collaborative planning, analysis, and wind integration project implementations. WINS will also have the capability of simulating energy storage facilities so that feasibility studies of integrated wind energy system applications can be performed for systems with high wind energy penetrations.

Methods: The development and the implementation of WINS will rely on the project team's extensive experience with wind integration studies. WINS will signify a major expansion of an existing decision tool called POver Market Simulator (POMS), which is developed and utilized continuously by the PI and his colleagues. The expanded features include the hourly power system scheduling based on security-constrained unit commitment, transmission loading and congestion, nodal pricing based on wind integration, wind-storage coordination, modeling of DC transmission, modeling of correlations between hourly load and wind forecasts, and a powerful visualization tool for demonstrating the wind integration results. WINS will be able to handle hourly unit commitment solutions for the entire Eastern Interconnection with over 50,000 buses and 70,000 branches. WINS will include an extensive user interface capability and a visualization tool for transmission analyses, planning, and assessment, which will be of great interest to power market participants, system planners and operators, and regulatory entities.

Project Team: The proposed project is a coordinated effort by an expert team of university and industry personnel including university participants from Illinois Institute of Technology (IIT), industry participants from McCoy Energy Consulting, Wiedman Power System Consulting, Acciona Energy, and the National Renewable Energy Laboratory (NREL). The project team will be supported by industry consultants from Exelon/ComEd, the ISO New England, Southern California Edison, and British Columbia Transmission Corporation. The university participants will develop the proposed WINS with a strong support of industry participants and NREL scientists. The industry consultants will further contribute to this project by ensuring the technology relevance, verifying the proposed model and the results, and enhancing the proposed solutions based on their extensive experience with ongoing wind energy developments.

Outcomes and Benefits: Upon the successful completion of the proposed project, WINS will assist power market participants including transmission companies, independent system operators, power system operators in vertically integrated utilities, wind energy developers, and regulatory agencies to analyze economics, security, and reliability of various options for wind integration including transmission upgrades and the planning of new transmission facilities. WINS can also be used by industry for the offline training of reliability and operation personnel when analyzing wind integration uncertainties, identifying critical spots in power system operation, analyzing power system vulnerabilities, and providing credible decisions for examining operation and planning options for wind integration. Upon the completion of the proposed study, a prototype version of WINS including a publicly available set of data, the proposed WINS features, and supporting documents will be made available to DOE.

3. Results and Discussions

3.1 Wind Integration Research and Development

3.1.1 Development of WINS

Wind INtegration Simulator (WINS) is a decision tool that can facilitate the analyses for the integration of 20% or more wind energy. WINS explores innovative solutions for continuing reliable operation of existing grid with the most economic integration of additional wind energy. WINS offers the scheduling of wind power across interties and adopting new transmission for wind integration. WINS represents advanced features for the modeling and simulation of energy storage, DC transmission lines, hourly wind availability and system reserves, transmission utilization and congestion studies, optimal production costing and nodal price calculations, and advanced visualization techniques for representing the hourly results and facilitates operator training for wind integration. WINS represents a major expansion of a very efficient decision tool called POver Market Simulator (POMS), which was developed by IIT and has been used extensively for power system studies for decades. POMS offers outstanding features for power market simulation which will be embedded into WINS. WINS focuses on augmenting the existing power utility capabilities to support collaborative planning, analysis, and implementation of wind integration. In particular, WINS provides the following superiorities:

- An integrated framework is included in WINS for the comprehensive modeling of DC transmission configurations, including mono-pole, bi-pole, tri-pole, back-to-back, and multi-terminal connection, as well as AC/DC converter models including current source converters (CSC) and voltage source converters (VSC).
- An existing shortcoming of traditional decision tools for wind integration is the limited availability of user interface, i.e., decision results are often text-based demonstrations. WINS includes a powerful visualization tool and user interface capability for transmission analyses, planning, and assessment, which will be of great interest to power market participants, power system planners and operators, and state and federal regulatory entities.
- WINS can handle extended transmission models for wind integration studies. WINS models include limitations on transmission flow as well as bus voltage for analyzing power system states. The existing decision tools often consider transmission flow constraints (dc power flow) alone which could result in the over-utilization of existing resources when analyzing wind integration.

The input WINS data include (1) generation data (unit type, capacity, availability; cost information; unit operating constraints such as max/min capacities, ramping up/down rates, min on/off times, maximum number of start-ups); (2) wind data (8760 hourly profile); (3) transmission data (network topology, line parameters, control transformers, normal/contingency limits for line flows and bus voltages); and (4) load data (hourly load and distribution, demand bids and load shedding cost and data).

WINS simulates the actual market operations which is based on the security-constrained unit commitment (SCUC) with full AC transmission and voltage constraints considered. The computational

engine of WINS is written in Microsoft Visual C++, and the Graphical User Interface (GUI) is written in Microsoft Visual C# and ASP.NET. The database is based on ORACLE and can be extended to include other database formats as well. Microsoft Excel is used for the downloading reports.

Figure 1 shows the overall architecture for the design and the implementation of WINS. Figure 2 to Figure 5 shows the sample tabular/graphical input/output screenshots of the web-based WINS.

Figure 1: Architecture for the Design and the Implementation of WINS

Home > SCUC > Inputs > GENCOs input > Fossil Units

Download Data Add New Unit

	Unit Name	Area Name	Zone Name	Owner Name	Unit Id	Bus No	Min Capacity (MW)	Max Capacity (MW)	Min Capacity (MW)	Max Capacity (MW)	Min Up Time (Hours)	Min Down Time (Hours)	Ramp Up (MW/Hour)	Ramp Down (MW/Hour)	Quick Start Capability (MW)
Edit Delete	TG1	Area1	Zone1	GENCO3	1	4	5.00	30.00	-300.00	300.00	1	1	15.00	15.00	30.00
Edit Delete	TG2	Area1	Zone1	GENCO3	1	6	5.00	30.00	-13.00	50.00	1	1	15.00	15.00	30.00
Edit Delete	TG3	Area1	Zone1	GENCO3	1	8	5.00	30.00	-300.00	300.00	1	1	15.00	15.00	30.00
Edit Delete	TG4	Area1	Zone1	GENCO3	1	10	150.00	300.00	-147.00	200.00	8	8	150.00	150.00	0.00
Edit Delete	TG5	Area1	Zone1	GENCO3	1	12	100.00	300.00	-35.00	120.00	8	8	150.00	150.00	0.00
Edit Delete	TG6	Area1	Zone1	GENCO3	1	15	10.00	30.00	-10.00	30.00	1	1	15.00	15.00	30.00
Edit Delete	TG7	Area1	Zone1	GENCO3	1	18	25.00	100.00	-16.00	50.00	5	5	50.00	50.00	0.00
Edit Delete	TG8	Area1	Zone1	GENCO3	1	19	5.00	30.00	-8.00	24.00	1	1	15.00	15.00	30.00
Edit Delete	TG9	Area1	Zone1	GENCO3	1	24	5.00	30.00	-300.00	300.00	1	1	15.00	15.00	30.00
Edit Delete	TG10	Area1	Zone1	GENCO2	1	25	100.00	300.00	-47.00	140.00	8	8	150.00	150.00	0.00
Edit Delete	TG11	Area1	Zone1	GENCO2	1	26	100.00	350.00	-1,000.00	1,000.00	8	8	175.00	175.00	0.00
Edit Delete	TG12	Area1	Zone1	GENCO2	1	27	8.00	30.00	-300.00	300.00	1	1	15.00	15.00	30.00
Edit Delete	TG13	Area1	Zone1	GENCO2	1	31	8.00	30.00	-300.00	300.00	1	1	15.00	15.00	30.00
Edit Delete	TG14	Area1	Zone1	GENCO2	1	32	25.00	100.00	-14.00	42.00	5	5	50.00	50.00	0.00
Edit Delete	TG15	Area2	Zone2	GENCO2	1	34	8.00	30.00	-8.00	24.00	1	1	15.00	15.00	30.00
Edit Delete	TG16	Area2	Zone2	GENCO2	1	36	25.00	100.00	-8.00	24.00	5	5	50.00	50.00	0.00
Edit Delete	TG17	Area2	Zone2	GENCO2	1	40	8.00	30.00	-300.00	300.00	1	1	15.00	15.00	30.00
Edit Delete	TG18	Area2	Zone2	GENCO2	1	42	8.00	30.00	-300.00	300.00	1	1	15.00	15.00	30.00
Edit Delete	TG19	Area2	Zone2	GENCO3	1	46	25.00	100.00	-100.00	100.00	5	5	50.00	50.00	0.00
Edit Delete	TG20	Area2	Zone2	GENCO3	1	49	30.00	250.00	-85.00	210.00	8	8	125.00	125.00	0.00
Edit Delete	TG21	Area2	Zone2	GENCO3	1	54	50.00	250.00	-300.00	300.00	8	8	125.00	125.00	0.00

Figure 2: Web-based WINS – Sample Tabular Input Screenshot

Home > SCUC > Outputs > TRANSCOs output > Bus Voltage Magnitude

All TransCos Download Data

BUSNO	NAME	LOWERLIMIT	UPPERLIMIT	H1	H2	H3	H4	H5	H6	H7	H8	H9	H10	H11	H12	H13	H14
1	BUS1	0.94	1.05	1.0080	0.9948	0.9703	0.9784	0.9686	0.9680	0.9724	0.9816	0.9854	0.9843	0.9857	0.9687	0.9671	0.9785
2	BUS2	0.95	1.06	1.0205	1.0072	0.9817	0.9854	0.9773	0.9801	0.9865	0.9962	1.0038	1.0035	1.0042	0.9860	0.9833	0.9926
3	BUS3	0.95	1.06	1.0167	1.0028	0.9775	0.9832	0.9752	0.9811	0.9916	0.9952	0.9946	0.9964	0.9792	0.9772	0.9884	
4	BUS4	0.99	1.05	1.0458	1.0293	1.0005	0.9981	0.9964	0.9985	1.0096	1.0259	1.0277	1.0289	1.0327	1.0145	1.0117	1.0222
5	BUS5	0.98	1.05	1.0483	1.0324	1.0032	0.9995	0.9991	1.0012	1.0128	1.0297	1.0312	1.0326	1.0367	1.0187	1.0154	1.0260
6	BUS6	0.97	1.09	1.0307	1.0160	0.9890	0.99	0.9948	0.9871	0.9957	1.0085	1.0127	1.0137	1.0159	0.9979	0.9950	1.0049
7	BUS7	0.97	1.05	1.0334	1.0190	0.9919	0.9919	0.9866	0.9905	0.9994	1.0116	1.0174	1.0192	1.0208	1.0022	0.9988	1.0077
8	BUS8	0.98	1.05	1.0540	1.0346	1.0032	1.0044	1.0023	1.0013	1.0168	1.0392	1.0358	1.0371	1.0444	1.0275	1.0237	1.0360
9	BUS9	0.98	1.09	1.0802	1.0601	1.0140	1.0112	1.0114	1.0115	1.0384	1.0659	1.0573	1.0607	1.0734	1.0522	1.0441	1.0608
10	BUS10	0.98	1.09	1.0783	1.0576	0.9971	0.9832	0.9870	0.9961	1.0337	1.0640	1.0525	1.0578	1.0728	1.0495	1.0374	1.0523
11	BUS11	0.97	1.08	1.0315	1.0167	0.9905	0.9912	0.9858	0.9892	0.9978	1.0104	1.0187	1.0171	1.0188	1.0089	0.9978	1.0068
12	BUS12	0.98	1.05	1.0409	1.0289	0.9994	0.9967	0.9917	0.9988	1.0085	1.0202	1.0249	1.0322	1.0528	1.0132	1.0089	1.0159
13	BUS13	0.95	1.05	1.0078	0.9911	0.9715	0.9795	0.9707	0.9710	0.9720	0.9884	0.9913	0.99	0.9917	0.9775	0.9768	0.9860
14	BUS14	0.98	1.07	1.0311	1.0141	0.9924	0.9933	0.9875	0.9932	0.9994	1.0153	1.0218	1.0232	1.0242	1.0083	1.0056	1.0120
15	BUS15	0.98	1.05	1.0144	0.9884	0.9819	0.9867	0.9817	0.9856	0.9848	1.0133	1.0135	1.0108	1.0132	1.0071	1.0087	1.0115
16	BUS16	0.98	1.07	1.0273	1.0110	0.9902	0.9944	0.9861	0.9911	0.9969	1.0171	1.0229	1.0235	1.0243	1.01	1.0080	1.0137
17	BUS17	0.98	1.09	1.0343	1.0112	1.0012	1.0064	0.9998	1.0060	1.0095	1.0518	1.0535	1.0519	1.0538	1.0488	1.0482	1.0482
18	BUS18	0.98	1.07	1.0297	0.9851	0.9804	0.9844	0.9812	0.9941	0.9970	1.0314	1.0312	1.0294	1.0334	1.0274	1.0286	1.0294
19	BUS19	0.98	1.06	1.0205	0.9934	0.9898	0.9813	0.9887	0.9935	0.9943	1.0210	1.0202	1.0184	1.0218	1.0160	1.0171	1.0189
20	BUS20	0.98	1.04	1.0074	0.9880	0.9851	0.9752	0.9767	0.9904	0.9788	0.9974	0.9945	0.9956	0.9984	0.9921	0.9920	0.9917
21	BUS21	0.98	1.03	1.0046	0.9907	0.9870	0.9778	0.9728	0.9938	0.9743	0.9880	0.9842	0.9888	0.9908	0.9843	0.9821	0.9801
22	BUS22	0.97	1.04	1.0183	1.0084	1.0013	0.9802	0.9788	1.0094	0.9851	0.9947	0.9900	1.0026	1.0030	0.9864	0.9894	0.9853
23	BUS23	0.98	1.09	1.0534	1.0356	1.0386	0.9987	1.0021	1.0484	1.0223	1.0260	1.0262	1.0558	1.0510	1.0462	1.0265	1.0154

Figure 3: Web-based WINS – Sample Tabular Output Screenshot

Figure 4: Web-based WINS – Sample Graphical Input Screenshot

Figure 5: Web-based WINS – Sample Graphical Output Screenshot

3.1.2 Wind Integration Studies

A. Wind Energy Integration in the Eastern Interconnection

Wind energy has become increasingly popular across the globe and shown a prosperous future of large-scale development and integration. Wind energy would produce great benefits with reductions in emissions and the supply of zero cost energy. However, the intermittent and the volatile nature of wind power generation would impact power system operations such as voltages, frequency and generation adequacy, which can potentially increase the vulnerability of power systems. The large-scale integration of wind energy would bring inevitable challenges to current transmission system and power system operations. The electricity market would require a detail simulation of the adequacy of generation portfolio and transmission capacity before integrating the large-scale wind energy into existing power systems. The uncertain factors such as fuel price, wind speed, load, and carbon cost, which could also have major impacts on the system operation of current power system. Comprehensive simulation and study of the impacts of these uncertain factors is necessary and could provide valuable information for operator or analyst.

There are three major alternating current (AC) power grids in the United States, the eastern interconnection, the western interconnection, and the Texas Interconnection, as shown in Figure 6. Figure 7 illustrates the transmission grid in the United States in which various colors represent voltage levels (e.g., red lines represent 345KV transmission branches). All the interconnections can be tied to each other via high-voltage direct current power transmission lines (DC ties) or variable frequency

transformers (VFTs), which permit a controlled flow of energy between each other while also functionally isolating the independent frequencies inside of each interconnection.

The eastern interconnection is the largest interconnection which include about 70,000 branches and 30,000 load buses and above 5,000 units. All of the electric utilities in the Eastern Interconnection are electrically tied together during normal system conditions and operate at a synchronized frequency at an average of 60Hz. The Eastern Interconnection is tied to the Western Interconnection with six DC ties, to the Texas Interconnection with two DC ties, and to the Québec Interconnection with four DC ties and a VFT.

The mass of transmission and generating components introduce major challenges to related simulation and analysis. The NETCS Report, issued in August 2006 and December 2009 successively, identified transmission congestions and constraints in the Eastern and the Western Interconnections [1], [2], [3] proposed a definition of a power transmission corridor and measured their importance in the Eastern Interconnection. An ongoing project is to analysis transmission requirements under a broad range of alternative futures and develops long-term interconnection-wide transmission expansion plans in the Eastern Interconnection [4].

Figure 6: Interconnections in North America [5]

Figure 7: Power Transmission Network in the United States

This section focuses on large-scale power system simulation and analysis, congestion identification, large-scale wind energy integration.

Section B applies a SCUC based methodology for the congestion analysis in the Eastern Interconnection of United States for 2008 and 2018. The simulation results are compared with those in the NETCS report. The simulation results are integrated with GIS data to offer a comprehensive and intuitive understanding of transmission constraints and LMPs.

In Section C, a comprehensive large-scale wind energy integration analysis is implemented based on the 2030 load forecast in the Eastern Interconnection of the United States. Transmission congestions are assumed be eliminated completely as a result of continuous transmission expansion planning, so the hourly unit commitment is applied to simulate the hourly operation with large-scale wind energy integration. Different levels of wind energy integration are studied in detail based on the capacity factors of potential wind sites. Wind energy, non-wind energy, wind energy contribution percentage and production cost are studied based on the annual simulation results, and also they are studied for peak/off-peak load hours respectively. The sensitivity of fuel cost, wind energy output, hourly load, carbon cost and load management are analyzed in order to study the impact of wind integration in possible scenarios.

Section D presents the hourly simulation results for the year 2018 with the large-scale wind energy integration in the Eastern Interconnection of the United States. A simulator referred to as WINS (Wind

INtegration Simulator) is developed for this annual study. The wind energy integrations in the year 2018 are simulated using the hourly security-constrained unit commitment (SCUC) in WINS. The generation portfolio for supplying the hourly load in 2018 is developed with/without transmission network constraints. The sensitivities to the 2018 wind energy integration are carried out for fuel price, wind energy availability, load growth, carbon cost, and hourly load management strategies. The hourly production cost, generation credit, load payment, levelized congestion cost, LMPs, and wind energy contribution, are calculated and analyzed.

B. Transmission Congestion Analysis in the Eastern Interconnection using POMS

A methodology based on the security-constrained unit commitment (SCUC) is applied to analyze the transmission congestion in the Eastern Interconnection of the United States for 2008 and 2018. The proposed SCUC tool for this study is referred to as the POver Market Simulator (POMS). The identified congestions are visualized along with the Geographical Information System (GIS) data and compared with the results published by the U.S. Department of Energy's National Electric Transmission Congestion Study (NETCS) in 2006. The POMS study also provides the locational marginal price (LMP) information in the Eastern Interconnection, which is not available in the NETCS report. The POMS simulation results for representing congested branches and LMPs could be applied to the future transmission expansion planning studies.

The identification of possible congestion sites is the first step in any grid expansion and reinforcement studies. The Federal Power Act (FPA) 216(a) resulted in a study of the electric transmission congestion in the United States [Dep05]. The first congestion study report, known as the NETCS report and issued in August 2006, identified congestions and constraints in the Eastern and the Western Interconnections [1]. The NETCS report included the review of the available information on historical congestions, the simulation of future congestions, and the comparison of simulation results with the historical information. Another published report analyzes the available 2007 data for assessing the transmission congestions in the Eastern Interconnection [2]. For the purpose of comparison, this chapter will focus on the NETCS report published in 2006.

This chapter focuses on the congestion studies in the Eastern Interconnection by applying SCUC. In addition, the congestion and LMP results are visualized along with the GIS data. The rest of this chapter is organized as follows. Section 2.2 describes the proposed methodology for indentifying congestions and Section 2.3 presents the congestion study results for the Eastern Interconnection in 2008 and 2018. The study results of 2008 are also compared with the results in the NETCS report. Section 2.4 concludes the study in this chapter.

B1. Methodology for Identifying Congestion

The tool used for this study is called POver Market Simulator (POMS), which has been used extensively for power system studies for decades. The methodology in POMS simulates the hourly electricity market operation based on SCUC for identifying possible congestions. The congestion in this chapter is defined as a state in which the flow on a branch has reached the branch capacity. The POMS simulation results

have several advantages over those of the optimal power flow (OPF). A POMS simulation study considering the commitment and the redispatch of generating units will provide a more realistic picture of possible scenarios. In essence, it may be necessary to consider potential changes in the hourly unit commitment to satisfy certain constraints.

Figure 8: SCUC Solution for the Eastern Interconnection

The POMS applications to the Eastern Interconnection simulation consider a decomposition and coordination strategy shown in Figure 8. A similar procedure is followed for considering contingencies [6], [7], [8], [9].

In NETCS, five metrics were defined to assess the magnitude of transmission congestion, including binding hours, U90, all-hour shadow prices, binding hour shadow prices, and congestion rents. The metrics used in this chapter include binding hours, U90 hours, constrained transmission capacity, LMPs, cost of served load, and congestion cost.

Binding Hours and U90 Hours

Those branches on which the flows have reached their limits are identified as congested branches. In addition, branches with flows above 90% of the flow limits are identified as U90 branches. In this chapter, two congestion metrics including the binding hours and the U90 hours [1], [3] are defined as follows which are based on a long term (e.g., 8,760 hours) POMS simulation.

$$\text{Binding hours of branch } l = \sum_{t=1}^{NT} x_{l,t} \quad (1)$$

$$x_{l,t} = \begin{cases} 1 & \text{if branch } l \text{ is congested at period } t \\ 0 & \text{otherwise} \end{cases}$$

$$\text{U90 hours of branch } l = \sum_{t=1}^{NT} y_{l,t} \quad (2)$$

$$y_{l,t} = \begin{cases} 1 & \text{if branch } l \text{ is loaded above 90\% of its capacity at period } t \\ 0 & \text{otherwise} \end{cases}$$

where NT represents the number of time periods (e.g., 8,760). These two definitions are similar to those in the NETCS report.

Similar to U90 hours, other metrics such as U75 hours or U60 hours can also be defined in order to assess the degree of congestion. These metrics can be used to classify and rank the identified congestions.

Constrained Transmission Capacity

The constrained transmission capacity of a system is the sum of the transmission capacity of all branches that are constrained at least in one hour during the study horizon. The constrained transmission capacity could be different when different congestion metrics are used, e.g., binding hours and U90 hours. If binding hours is applied to identify congestions, the constrained transmission capacity is formulated as follows.

$$\begin{aligned} \text{Constrained transmission capacity} &= \sum_{l=1}^{NB} z_{l,1} * PL_{l,\max} \\ z_{l,1} &= \begin{cases} 1 & \text{if binding hours of branch } l > 0 \\ 0 & \text{if binding hours of branch } l = 0 \end{cases} \end{aligned} \quad (3)$$

where NB represents the number of branches and $PL_{l,\max}$ is the capacity of branch l . Similarly, if U90 hours is applied to identify congestions, the constrained transmission capacity is formulated as follows.

$$\begin{aligned} \text{Constrained transmission capacity} &= \sum_{l=1}^{NB} z_{l,2} * PL_{l,\max} \\ z_{l,2} &= \begin{cases} 1 & \text{if U90 hours of branch } l > 0 \\ 0 & \text{if U90 hours of branch } l = 0 \end{cases} \end{aligned} \quad (4)$$

LMPs

LMP is the cost of supplying the next MW of load at a specific location after considering costs associated with generation, transmission, and losses. LMPs at individual buses are calculated as part of the outputs from the SCUC based simulation. Since LMP differences in a system are caused by congestions, an LMP

map would provide an intuitive way of visualizing congestions across the system. LMP information is not discussed in the NETCS report.

Cost of Served Load

The cost of served load is the total payment made by all loads in the system, which is calculated as

$$\text{Cost of served load} = \sum_{t=1}^{NT} \sum_{j=1}^{ND} LMP_{j,t} * D_{j,t} \quad (5)$$

where ND represents the number of load buses; $LMP_{j,t}$ represents the LMP of load bus j at period t ;

$D_{j,t}$ represents the load at bus j at period t .

Congestion Cost

The congestion cost was calculated as the increase in the production cost due to the re-scheduling of units to alleviate congestions [10]. In this chapter, the congestion cost is defined as the difference between the load payment and the generation credit based on LMPs

$$\begin{aligned} \text{Congestion cost} = & \sum_{t=1}^{NT} \sum_{j=1}^{ND} LMP_{j,t} * D_{j,t} \\ & - \sum_{t=1}^{NT} \sum_{i=1}^{NG} LMP_{i,t} * P_{i,t} \end{aligned} \quad (6)$$

where NG represents the number of generator buses; $LMP_{i,t}$ represents the LMP at generator bus i at period t ; $P_{i,t}$ represents the generation at bus i at period t .

The congestion cost metric defined as (6) is similar to the congestion rent defined in the NETCS report [1]. Congestion cost as a percentage of the cost of served load could indicate the magnitude of congestion of the entire system.

B2. Numerical results

In this section, we utilize POMS to simulate the congestions in the Eastern Interconnection based on the 2008 and 2018 data. We compare the POMS simulation results with those in the NETCS report, referred to as NETCS results thereafter, and analyze the variations in the POMS simulation results from 2008 to 2018. Note that there are about 70,000 branches at all voltage levels in the Eastern Interconnection. We consider in the POMS simulation only those branches that are above 200kV along with 1,000 flowgates.

POMS Simulation Results for 2008

In this case, POMS is applied to simulate the 8,760 hours of generation dispatch and transmission flows in the Eastern Interconnection in 2008.

1) Transmission Congestions based on the Binding Hours Metric

The POMS simulation results show that in 2008 there are 1,325 congested branches, 270 of which are congested in all hours. A congested branch is a branch with a non-zero binding hour. The most congested branches are in the New York and the Chicago regions. There are also several congested branches in the boundary between Georgia and Florida. Figure 9 shows the zoomed-out version of the congested branches based on the binding hours metric.

Figure 9: Binding Hours Information in 2008

2) Constrained Branches based on the U90 Hours Metric

As expected, more transmission branches are constrained based on the U90 hours metric. There are 2,497 U90 branches, 483 of which are continuously loaded above 90% of their capacities. A U90 branch is branch with a non-zero U90 hour. The U90 branches are again concentrated in the New York region, the Chicago region, and the boundary between Georgia and Florida. Figure 10 shows the zoomed-out version of constrained branches based on the U90 hours metric.

Figure 10: U90 Hours Information in 2008

3) Number of Constrained Branches

Figure 11: Constrained Branches as a Function of Time in 2008

Figure 11 shows the number of constrained branches as a percentage of time. There are 1,325 congested branches and 439 (i.e. 33%) of these branches are congested in more than 80% of the annual hours and 600 (i.e. 45%) are congested in less than 20% of the annual hours. The U90 curve in Figure 11 has a similar pattern except that more branches are constrained based on the U90 metric. It is expected that more branches would be constrained if U75 was used as the metric.

4) Locational Marginal Prices

Figure 12: Annual Average of LMPs in 2008

Figure 12 shows the 2008 annual average LMPs based on the POMS simulation results. The New York region shows the highest LMPs in the Eastern Interconnection because of its limited generation capacity. Due to the existing transmission congestions, much of the low cost power from neighboring regions cannot be transmitted to the New York region. So, the LMPs in the New York region are high due to its dependence on local expensive units such as gas units and oil units for supplying the local load. The LMPs in New England and Florida are relatively high for similar reasons. Even though the Chicago region

also exhibits transmission congestion, the LMPs are not as high which is partly due to the cheap coal-fired and nuclear power generation close to the load centers. Large wind developments in the Midwest could provide large sums of low cost energy to the Midwest energy markets. So, LMPs in the northwest region of the Midwest are relatively low.

5) Cost of Served Load and Congestion Cost

Based on the 2008 POMS simulation, the total cost of served load is about \$172.3 billion. The total congestion cost is about \$13 billion which is about 7.5% of the total cost of served load. The total production cost is about \$75.3 billion. Figure 13 shows that the production cost as a function of the hourly load. A higher production cost would appear in hours 5000-5500 (July and August), which are consistent with higher loads experienced during this time.

Figure 13: Production Cost in 2008

POMS Simulation Results for 2018

The Eastern Interconnection is simulated in 2018 using POMS. The input data are based on the forecasts in the MISO MTEP 2008 (MISO Transmission Expansion Planning) study [11]. The loads are assumed to increase at an annual rate of 1.28% based on the 2008 loads. The fuel prices are assumed to increase at an annual escalation rate of 4% for oil and gas, 2% for coal, and 3% for nuclear fuels. The transmission and generation projects that are under construction or are planned by 2018 in the Eastern Interconnection are incorporated in the 2018 simulation. New England and Florida, which were not included in the MISO MTEP 2008 study, are excluded from the POMS simulation.

1) Transmission Congestion based on the Binding Hours Metric

The simulated 2018 congestion is shown in Figure 14. There are 2,665 branches that are congested for at least one hour and 314 of those branches are always congested in 2018. Most of the congested branches are in the New York and the PJM interconnections. Certain branches in the west side of the SERC region are also congested.

Figure 14: Binding Hours Information in 2018

2) Constrained Branches based on the U90 Hours Metric

Figure 15 shows constrained branches based on the U90 metric. There are 4,239 constrained branches based on U90 and 472 of those branches are continuously loaded in excess of 90% of their capacities. Such branches are mainly located in New York and in certain parts of the PJM system (including Chicago). A few branches are also constrained in the west side of the SERC region.

Figure 15: U90 Hours Information in 2018

3) Number of Constrained Branches

Figure 16 shows the number of constrained branches as a percentage of time. Out of 2,665 branches that are congested in at least one hour, 524 (i.e. 20%) remain congested in at least 80% of the annual hours and 1,599 (i.e., 60%) are congested in less than 20% of the annual hours. Based on the U90 metric, there are 4,239 branches that are constrained, 710 (i.e., 15%) of such branches remain constrained in at

least 80% of annual hours, and 2,715 (i.e., 65%) are constrained in less than 20% of the annual hours. The two curves have similar patterns except that more branches are constrained based on the U90 metric.

Figure 16: Constrained Branches as a Function of Time in 2018

4) LMPs

The annual average LMPs based on the 2018 simulation are shown in Figure 17. New York has the highest LMPs in the Eastern Interconnection. The LMPs in the East Coast are generally higher than those in other regions. High LMPs are also encountered in Louisiana and Mississippi indicating transmission congestions. LMPs in Illinois and Indiana are lower than those in the East Coast because there are cheap coal-fired and nuclear power plants close to load centers. LMPs in the Northwestern region of the Midwest are significantly lower than those in other regions due to expected high penetration of wind power.

Figure 17: Annual Average LMPs in 2018

Figure 18: Production Cost in 2018

5) Cost of Served Load and Congestion Cost

The total cost of served load in 2018 is about \$230.9 billion and the total congestion cost is about 10% of the total cost of served load. The total production cost in 2018 is \$83.6 billion with the hourly costs shown in Figure 18, where higher hourly production costs appear in July and August.

Comparison of POMS and NETCS Results in 2008

In this section, we compare the 2008 POMS simulation results with the NETCS results. The NETCS report reviewed the historical congestions and analyzed the 2008 congestion in the Eastern Interconnection using the optimal power flow (OPF) model [1].

1) Regional Congestion

The POMS and the NETCS simulation results show that congestions are concentrated in the New York and the PJM regions (including Chicago). In addition, congestions are identified at the border between Georgia and Florida. With high LMPs in Florida, the cheaper energy is imported to the state which leads to congestions at the border. These congestions were not presented in the review of historical information in the NETCS report because the actual power transactions between Florida and Georgia are based on long term contracts which would limit the power flow across the Georgia-Florida border.

2) Number of Congested Paths/Branches

In NETCS, 58 historically congested paths were identified with the detailed geographical information given in [1]. In the simulation results presented in NETCS, 171 congested transmission paths were identified in 2008. In comparison, the POMS simulation results for 2008 identified 270 congested branches that always constrained based on the binding hours metric. The difference is due to the fact that one transmission path in the NETCS report may represent several branches although the details are not given in the NETCS report.

One notable point is that both the NETCS and the POMS simulation results identify more congestions than what is reported by the historical data. This is due to the assumption in both simulations that economic transactions occur whenever is possible. A two-bus example presented in the Appendix A

illustrates how economic transactions could cause additional congestions. It should be pointed out that almost all historical congestions have also been identified in the NETCS simulation results and the POMS simulation results.

3) Constrained Transmission Capacities

Figure 19: Constrained Transmission Capacity (%) as a function of Time in 2008

Figure 19 shows the percentage of constrained transmission capacity as a function of time and Figure 20 shows the constrained capacity (GW) as a function time in 2008. In particular, it is shown in Figure 19 that about 23% of the constrained transmission capacity is congested more than 80% of the annual hours based on the Binding Hours curve, and about 30% of the constrained transmission capacity is congested more than 80% of annual hours based on the U90 Hours curve. Note that the U90 branches will always include the congested branches and that is why the U90 Hours curve is above the Binding Hours curve in Figure 19 and Figure 20.

In NETCS, heavy congestion occurs in only a few hours per year. For instance, 80% of the congestion occurs for less than 20% of the annual hours [1]. In comparison, the POMS simulation results in Figure 19 show more congestion. In the latter case, 50% of the congestion occurs in less than 20% of the annual hours.

Figure 20: Constrained Transmission Capacity (GW) as a function of Time in 2008

This difference can be attributed to the differences in the input data and the modeling details. For instance, both branch flowgate limits are taken into account in the POMS simulation, while only branch limits are monitored in the NETCS. In addition, the NETCS was completed in 2006. Thus, some transmission projects that were completed since then might not be included in the NETCS simulation. It is also possible that certain transmission projects that were assumed in the NETCS are not built and thus not included in the simulation in this chapter.

In Figure 19, the two curves coincide beyond the 60% constrained transmission capacity point, i.e., about 40% of constrained transmission capacity is constrained less than 10% of the time. The difference between the two curves is more obvious in Figure 20. 228 GW of transmission capacity is congested based on Binding Hour metric and 588 GW is congested based on the U90 Hour metric.

Figure 21 also shows the constrained transmission capacity as a function of time. However, only the congested transmission branches are considered in calculating the constrained transmission capacity in both cases. In contrast to Figure 19, the two curves in Figure 21 are more distinguishable. For instance, 40% of the congested transmission capacity is congested as least 40% of the binding time. The same transmission capacity will be loaded to 90% or more at 70% of the time.

Figure 21: Constrained Transmission Capacity as a function of Time in 2008 (congested capacity is used as base)

4) Congestion Costs

In the POMS simulation results for 2008, the total cost of served load is \$172.3 billion and the congestion cost is about 7.5% of the total cost. In comparison, in the NETCS report, the total cost of served load is about \$171 billion and the congestion cost is about 4.7% of the total cost. That is, the total costs in two cases are almost the same but the POMS simulation results show more congestion. Figure 2.15 shows the relationship between the congestion cost and the constrained transmission capacity for the POMS simulation in 2008 and 2018. For the 2008 case, 20% of the constrained transmission capacity accounts for about 73% of the total congestion cost and 50% of the constrained transmission capacities account for 97% of the total congestion cost. For the 2008 case in the NETCS report, 20% of the constrained transmission capacity accounts for 60% of the total congestion cost and 50% of the

constrained transmission capacity accounts for 95% of the total congestion cost [1]. The POMS simulation results are similar to those of the NETCS in this case.

Figure 22: Congestion Cost and the Constrained Transmission Capacity

The POMS simulation results in Figure 22 also show that the congestion cost is caused by a small number of constrained branches. The POMS results are similar to the NETCS results. Since the congestion cost is ultimately passed through to consumers, this also means that the planning of a relatively small number of transmission projects along constrained transmission paths could lead to a significant reduction in congestion costs and introduce a major economic benefit to consumers.

Comparison of POMS Results in 2008 and 2018

In this section, we compare the POMS simulation results for 2008 and 2018.

1) LMPs

Figure 12 and Figure 17 show that LMPs in 2018 are higher than those in 2008. In fact, the average load-weighted LMP in the Eastern Interconnection increases from \$48.85/MWh in 2008 to \$65.93/MWh in 2018. The higher LMPs could be attributed to increased loads and fuel prices.

2) Production and Congestion Costs

The total production cost in 2008 is about \$75.3 billion as compared to \$83.6 billion in 2018. The hourly production costs in 2018 (Figure 18) and 2008 (Figure 13) are similar. In both cases, higher production costs appear in the summer months (July and August). As expected, the hourly production costs in 2018 are higher than those in 2008 due to the load growth and fuel price escalations. Even though the New England and the Florida are not considered in the 2018 simulation, the total cost of served load increases from \$172.3 billion in 2008 to \$230.9 billion in 2018. It is interesting to note that the total cost of served load increases by 34% while the total production cost increases by 11%. This phenomenon can be explained using a two-bus example below.

The one-line diagram of a two-bus system with two generators and two loads is shown in Figure 23. G1 and L1 are located at Bus 1 and G2 and L2 are located at Bus 2. The capacities for both generators are 800MW and the incremental cost is 10\$/MWh for G1 and 20\$/MWh for G2. L1 is 400MW and L2 is 600MW. Bus 1 and Bus 2 are connected through one transmission line with a capacity of 300MW. In the ideal case, G1 and G2 will be dispatched to 700MW and 300MW, respectively. The economic transaction between Bus 1 and Bus 2 will be 300MW. Accordingly, the flow on the line will be 300MW, which makes the line congested. However, if we intentionally limit the power transaction between Bus 1 and Bus 2 to 100MW, there will be no congestion on the line. This shows that economic transactions could cause congestions that are not present without the economic transactions

Figure 23: Two-Bus System

We assume the L1 is 250MW and L2 is 250MW at first. So the system will have no congestion. All the loads will be supplied by G1 and the production cost is \$5,000 and the cost of served load is \$5,000. If L1 and L2 are both increased by 50MW, the power flow on the transmission line will reach its limit 300MW. G2 will be the marginal generator at Bus 2 and the LMP at Bus 2 will be \$20/MWh. The production cost is \$6,000, and the cost of served load is \$9,000. That is, the production cost increases by about 20% and the cost of served load increases by about 80% owing to the growth of loads.

The congestion cost as a percentage of the cost of supplying the load increases from 7.5% in 2008 to 10% in 2018, which shows that the system is more congested in 2018 due to the load growth and higher fuel prices. The results would also point out that sufficient generation and transmission projects investments may not have been planned within the 10-year period.

Figure 22 shows that the 2018 curve is a little higher than the 2008 curve, 20% of the congested transmission capacity accounts for about 73% of the total congestion cost in 2008 while 20% of the congested transmission capacity accounts for 83% of the total congestion cost in 2018. This means that congestion costs are more concentrated on a small percentage of constrained transmission capacity in 2018 than in 2008. Figure 22 also shows that 50% of the congested transmission capacity accounts for 97% of the total congestion cost in 2008 and that 50% of the congested transmission capacity accounts for 98% of the total congestion cost in 2018. This means that the congestion cost is attributed to half of the congested capacity. In Figure 22, the two curves almost coincide above the 50% of congested transmission capacity, which shows that the other 50% of the congested transmission capacity has very small impact on the congestion cost in both 2008 and 2018.

3) Constrained Transmission Capacity as a Function of Time

Figure 24 shows the percentage of constrained transmission capacity as a function of time. Figure 25 shows the MW constrained transmission capacity as a function of time in 2018. In 2018, about 549GW of transmission capacity is congested, 4.9% of which is continuously congested and 66% is congested less than 20% of the time in one year. Based on the U90 metric, about 944GW of the transmission capacity is constrained, about 5.4% of which is constrained continuously in one year. In 2008, 228GW of transmission capacity is congested, about 11% of which is congested continuously for the entire year and 50% is congested less than 20% of the time in one year. Based on the U90 metric, about 588GW transmission capacity is constrained in 2008, about 15% of which is constrained continuously for the entire year.

In Figure 24, the two curves are closer in comparison to Figure 19. This means that the transmission capacities that are identified as constrained by the U90 metric would be more often constrained in 2018 than in 2008. In Figure 24, the two curves coincide beyond the 40% constrained transmission capacity which account for about 15% of the time, so about 60% of constrained transmission capacity is constrained only in a few hours for the one year. Again we see that the congestion would be more confined to a small percentage of constrained transmission capacities in 2018 as compared with those in 2008.

Figure 24: Constrained Transmission Capacity as a Function of Time in 2018

Figure 25: Percent of Time and Constrained Transmission Capacity in 2018

B3. Conclusions

In this section, a SCUC based methodology is proposed in POMS for the congestion analysis in the Eastern Interconnection for 2008 and 2018. The POMS simulation results are compared with those in the NETCS report. The simulation results are integrated with GIS data to offer a comprehensive and intuitive understanding of transmission constraints and LMPs. The proposed methodology and the simulation result can provide valuable information for transmission expansion studies.

C. Analysis of 2030 Large-Scale Wind Energy Integration in the U.S. Eastern Interconnection

A simulation of the 2030 load forecast in the Eastern Interconnection suggests that large-scale wind energy integration will have a major impact on the hourly commitment and dispatch of gas and coal units, especially at off-peak load hours. While fuel price alterations will have major impacts on the system production cost, load variation will have a larger impact and potential carbon costs will have the greatest impact.

Wind energy is an important component of the future energy portfolio throughout the world. In the United States, wind energy is expected to provide 20% of the electricity by 2030 [12], [13], [14]. However, the electricity market would require a detail simulation of the adequacy of energy portfolio before integrating the large-scale wind energy into the existing power systems.

The Eastern Interconnection is the largest interconnection in the world with more than 5,000 generating units and about 70,000 branches. The National Renewable Energy Laboratory initiated a study in 2008 to examine the impact of 20-30% wind energy penetration in the Eastern Interconnection [15]. The western wind and solar integration study in 2007 examined the operational impact of 35% renewable energy penetration in the Western Interconnection [16]. The impact of wind integration on power system operations is analyzed further in [17], [18].

An hourly unit commitment and economic dispatch model for analyzing large-scale power system operations was represented in [9]. A follow-up optimization-based SCUC model [6], [8], [19] was presented in [20] which took into account the intermittency and volatility of wind power generation and transmission network constraints.

In this section, we focus on studying the large-scale security-constrained wind energy integration in the Eastern Interconnection in 2030. The wind energy sites are analyzed and the impact of large-scale wind integration on existing generation resources and production costs are studied. Fuel price sensitivity, wind energy production sensitivity, load growth sensitivity, carbon cost sensitivity, and load management strategies are considered and analyzed in this chapter for the large-scale wind energy integration.

The rest of this section is organized as follows. Section C1 describes the proposed methodology, assumption and relevant evaluation metrics. Section C2 presents the wind energy integration study results for the Eastern Interconnections. The conclusions drawn from the study is provided in Section C3.

C1. Methodology for Wind Energy Integration

At Illinois Institute of Technology (IIT), we had developed over the years an efficient decision tool called POMS [21] for the day-ahead scheduling of large scale power systems. The expansion of POMS, which is referred to as WINS (Wind INtegration Simulator), is considered in this study to support the collaborative planning, analysis, and implementation of the large-scale wind energy integrations in the United States. The WINS architecture is depicted in Figure 26.

WINS applies unit commitment to simulate large-scale wind energy integrations in the hourly power system operation. The application of WINS in this chapter analyzes the impact of large-scale wind energy integration in the year 2030 on production costs, unit commitment, and dispatch of generation resources in the Eastern Interconnection. For the purpose of this energy adequacy study, we do not consider transmission constraints in this chapter. We use wind data given in [15]. A brief description of the wind data is given in [22]. The wind uncertainty is simulated by sensitivity analyses applied to the wind energy integration Scenarios.

Figure 26: Framework of WINS

Input Data

It is estimated that approximately 225GW of wind power generation is required to supply the 20%, and 330GW is required to supply the 30% of the total energy by 2024 in the Eastern Interconnection [15]. In this chapter, we utilize the land-based time series wind simulation results [15]. The potential land-based wind sites in the Eastern Interconnection are shown in Figure 27 for about 580GW of wind power generation capacity. The figure shows that there are potential wind sites with rich wind resources in the central parts of the United States.

In this study, we consider a 1.28% annual load growth rate which is based on the MTEP 2008 data. The hourly load distribution shown in Figure 28 is based on the MISO's hourly load profile in 2007 [11]. In Figure 28, peak load hours appear in July and August. The power flow solution is used for calculating the hourly load distribution at each bus.

Fuel prices are assumed to increase at an annual rate of 4% for oil and gas, 2% for coal, and 3% for nuclear fuel based on the fuel price given in 2008 [11].

Figure 27: Potential Wind Sites in the Eastern Interconnection

Figure 28: Annual Hourly Load Profile

Evaluation Metrics

The evaluation criteria and metrics used in the simulations are defined as follows.

Wind Energy Availability

The available wind energy is treated as dispatchable in WINS simulations. Here,

$$P_A = \sum_{t=1}^T \sum_{i=1}^{NG} P_i^{\max} w_{it} \quad (7)$$

where T represents the number of hours in a period (e.g., one year), NG represents the number of wind generators/farms, $P_i^{\max}$ is the nominal capacity of wind generator/farm i , w_{it} represents the wind power profile i at time t , P_A represents the system wind availability in the given study period.

We assume the available wind energy is much less than the total system load in the Eastern Interconnection. Therefore, the total available wind energy is to be dispatched without any curtailment.

Percentage of Wind Energy Contribution

This metric is to evaluate the percentage of wind energy contribution to the total energy utilized for supplying the load in the power system.

$$= \frac{\text{Wind Ener}_{gy}}{\text{Total Ene}_{rgy}} * 100 \% \quad (8)$$

C2. Numerical Results

In this section, we utilize WINS to simulate the wind integration in the Eastern Interconnection of the United States based on the methodology presented in Section C1.

Level of Wind Integration

We simulate the hourly power system operation using WINS for a given wind power capacity factor (CF). Four scenarios are studied as follows.

- Scenario 1: No wind integration
- Scenario 2: Wind energy integration with a minimum 40% CF
- Scenario 3: Wind energy integration with a minimum 30% CF
- Scenario 4: Integration of all potential wind energy sites

Scenario 1: No Wind Integration. This is the base case in which the hourly loads will be served by fossil fuel and hydro units. Figure 29 shows the hourly production cost which is \$217.5 billion per year with an average production cost of \$45.64/MWh. The production cost will not change linearly with the hourly load fluctuations. Hydro units will have zero costs and be scheduled first to serve hourly loads or reserves; then cheaper units such as nuclear, coal, and large oil will be committed as loads pick up, and finally expensive units such as gas and oil will be committed to supply hourly loads. A higher production cost will occur at annual peak hours of 5000-5500 (i.e., July and August.) The production cost at peak hours (6AM-10PM) will be \$177.8 billion and the production cost at off-peak hours (11PM-5AM) will be \$39.7 billion. The average production costs at peak/off-peak hours are \$50.2/MWh and \$32.5/MWh. The average production cost at peak load hours is higher when expensive generators are committed and dispatched.

Figure 29: Hourly Production Cost without Wind Integration

Scenario 2: Integration of Wind Energy Sites with a minimum 40% CF. There are 399 of such potential wind energy sites with a total wind generation capacity of 230.5GW. The largest annual CF is 49%. Figure 30 shows the 399 potential wind energy sites in the Eastern Interconnection in which wind energy resources are mainly located remotely in the central region of the United States. The total available wind energy with a minimum 40% CF in that region is 845.2TWh.

The 2030 energy forecast in the Eastern Interconnection is 4,783.2TWh which indicates that the potential wind energy is about 17.67% of the total energy portfolio. We assume the wind energy has zero fuel cost and transmission congestion is not considered. So the entire available wind energy will be dispatched to satisfy the hourly load.

Figure 30: Potential Wind Sites with $CF \geq 40\%$

Figure 31 shows the monthly wind energy in 2030. The wind energy resources are mostly available in spring or winter; however, peak loads occur in summer. January has the highest level of available wind energy of 86.4TWh which amounts to 21.11% of the total energy. March has the highest percentage for wind energy contribution (21.53%) because the load is lower than that of January. The available wind

energy is scarce in August while the highest level of load occurs in this month. So August represents the month with the least available wind energy and the percentage of wind energy contribution (i.e., 57.5TWh and 12.2%) to the total energy portfolio.

Figure 32 shows the wind energy contribution at peak and off-peak hours. The figure shows that the wind is usually rich at night as compared with that in the day time especially in the summer. The hourly average wind energy at peak/off-peak hours are 2.27TWh and 2.69TWh in August, and the percentages of wind energy contribution are 10.88% and 16.22% respectively.

Figure 31: Monthly Wind Energy and its Contribution to Total Energy in Scenario 2

Figure 32: Wind Energy Contribution at Peak/Off-Peak Hours in Scenario 2

Figure 33 shows the hourly production cost. Compared to Figure 29, the production cost is lower when the large-scale wind energy is integrated. The annual production cost is \$130.4 billion, which is about \$87.1 billion less than that in Scenario 1. The annual average production cost decreases from \$45.64/MWh to \$27.25/MWh when the wind energy is integrated. Here, the production costs at peak/off-peak hours are \$107.1 billion and \$23.2 billion, and the average production cost at peak/off-

peak hours are 30.1\$/MWh and 18.9\$/MWh respectively. The average production cost is lower in this Scenario at peak/off-peak hours.

Figure 33: Hourly Production Cost in Scenario 2

Scenario 3: Integration of Wind Sites with a Minimum 30% CF. In this case, 972 wind sites are introduced in Figure 34 with a total capacity of 481.5GW. Compared to Figure 30, additional wind energy sites located in Wisconsin, Illinois, Indiana, and other sites are considered in this Scenario.

Figure 34: Potential Wind Sites with CF $\geq$ 30%

Figure 35 shows the annual wind energy contribution is 1,596TW which amounts to 33.37% percentage of the energy portfolio. Figure 36 shows the monthly wind energy contribution at peak/off-peak hours. Compared to the simulation results in Scenario 2, 573 additional potential wind energy sites with a 251GW of capacity are added here with a lower CF between 30% and 40%. In this case, the added wind capacity is 108.9% (i.e., 481.5GW VS 230.5GW) while the wind energy contribution increases about 88.85% (i.e., 33.37% VS 17.67%).

Figure 35: Monthly Wind Energy and its Contribution to Total Energy in Scenario 3

Figure 36: Wind Contribution at Peak/Off-Peak Hours in Scenario 3

The production cost in Figure 37 is \$86.8 billion with an average hourly production cost of 18.14\$/MWh. The average production costs at peak/off-peak hours are 20.33\$/MWh and 11.33\$/MWh, respectively.

Figure 37: Hourly Production Cost in Scenario 3

Scenario 4: Integration of All Potential Wind Sites. There are 1,326 wind energy sites in the Eastern Interconnection with a total capacity of 580 GW. Figure 38 shows the monthly wind energy production and wind energy contribution. The annual wind energy production is about 1,816TWh and the annual percentage of wind energy contribution is about 38%. In this case, the minimum wind energy contribution will be more than 20% of the system load. Figure 39 shows the percentage of wind energy contribution at peak/off-peak hours. Here, the wind energy contribution to the total energy at peak hours in August is 21.33%, which is also the lowest period for the wind energy production. The wind energy in this period is 75.83TWh as compared to 38.67TWh in Scenario 2 and 68.52TWh in Scenario 3. The annual production cost is \$77 billion.

Figure 38: Monthly Wind Energy and its Contribution to Total Energy in Scenario 4

Figure 39: Wind Energy Contribution at Peak/Off-Peak Hours in Scenario 4

Figure 40 shows the hourly production cost with an average production cost of \$16.1/MWh, and peak/off-peak average production costs of \$18.19/MWh and \$10.04/MWh respectively. Compared to the simulation results in Scenarios 1-3, the production costs has dropped here as more wind energy sites are added. Figure 41 shows the wind energy contribution in all four Scenarios. Here, the gas unit

production has decreased as more wind energy is considered. Also, the energy supplied by coal units is lower which is replaced by the integrated wind energy units.

Figure 40: Hourly Production Cost in Scenario 4

Figure 41: Energy Portfolio in Wind Integration Scenarios

Figure 42-Figure 44 show the energy supplied by gas, coal and wind units in four Scenarios. These figures show that wind energy will replace some of the fossil energy especially at off-peak hours in the Eastern Interconnection. Figure 45 show the annual commitment results of existing power plants in four Scenarios, in which red dots represents the power plants in which at least one unit is committed for a minimum of one hour per year. Also, blue dots show the plants which will be off throughout the year as more wind energy is integrated in the Eastern Interconnection.

Figure 42: Hourly Energy Provided by Gas Units in Wind Integration Scenarios

Figure 43: Hourly Energy Provided by Coal Units in Wind Integration Scenarios

Figure 44: Hourly Wind Energy in Wind Integration Scenarios

Figure 45: Unit Commitment Result in Wind Integration Scenarios

Sensitivity Analysis

There are several uncertain factors in the Eastern Interconnection, including fuel price, hourly wind speed, hourly loads, and carbon costs, which could have major impacts on the large-scale wind energy integration and the energy portfolio. It is perceived that the accurate forecast for some of these factors might not be readily available. In this section, we apply sensitivity analyses, based on the simulation results for Scenario 2 to study the impact of fluctuations in such factors on the wind energy integration and the annual energy portfolio in the Eastern Interconnection. The simulation results for Scenario 2 are considered as the base case in this Section.

Fuel Price Sensitivity

We apply the sensitivity analysis to the WINS simulation results for 2030, given for Scenario 2, in which the potential wind energy sites with a minimum CF of 40% and a total energy contribution of 17.67% (which is close to the expected 20% wind contribution in 2030) were considered. The following four scenarios would consider the impact of fuel price forecast.

- Scenario 5: Actual fuel price would be 20% lower than the forecast
- Scenario 6: Actual fuel price would be 10% lower than the forecast
- Scenario 7: Actual fuel price would be 10% higher than the forecast
- Scenario 8: Actual fuel price would be 20% higher than the forecast

As expected, the fuel price escalation has no impact on the wind energy dispatch since the wind energy has a zero price and will always be dispatched. The production cost in Figure 46 will increase as fuel price increases. The increase in fuel price at peak hours will have a more pronounced impact on the production cost as more expensive units are committed.

Figure 46: Production Cost in Fuel Cost Scenarios

Wind Energy Output Sensitivity Analysis

We apply the sensitivity analysis to the 2030 simulation results for Scenario 2. Four scenarios are studied as follows.

- Scenario 9: Actual wind energy production is 20% lower than the forecast
- Scenario 10: Actual wind energy production is 10% lower than the forecast
- Scenario 11: Actual wind energy production is 10% higher than the forecast
- Scenario 12: Actual wind energy production is 20% higher than the forecast

Figure 47 shows that the wind energy contribution to the total energy production is about 20% when the actual wind energy is 10% percent higher than that in the base case.

Figure 48 shows that the total production cost decreases with the added wind energy production. Again, the production cost is more sensitive to the wind energy production at peak hours.

Figure 49 shows the energy portfolios in all four Scenarios. The energy produced by gas and coal units will decrease as the wind energy production is higher. Similar to that in Figure 47, the wind energy contribution is increased from 14% to 22%. The unit commitment and hourly generation dispatch show a similar pattern as that for Scenario 2.

Figure 47: Wind/Non-Wind Energy for Wind Energy Scenarios

Figure 48: Production Cost for Wind Energy Scenarios

Load Sensitivity Analysis

In this section, we study the impact of load forecast errors on the WINS base case simulation results for Scenario 2. We do the sensitivity analysis based the load forecast in 2030. Four scenarios are studied as follows.

- Scenario 13: Actual load is 20% lower than the forecast
- Scenario 14: Actual load is 10% lower than the forecast
- Scenario 15: Actual load is 10% higher than the forecast
- Scenario 16: Actual load is 20% higher than the forecast

The wind energy contribution, depicted in Figure 50, shows a 19.62% contribution to the total energy production in Scenario 14 when the actual load is 10% lower than the forecast. The wind energy contribution will decline as the actual load escalates because the additional load will be served by other types of units. The production costs in Figure 51, as compared to those in previous sections, show that the system load will have the largest impact on production costs. Here, the production cost increases a lot between Scenarios 13 and 16. The production cost at peak hours is more sensitive to load variations.

Figure 52 shows the energy contribution in the given four Scenarios. The nuclear, hydro, and wind unit with their inexpensive fuel will supply much of the hourly load. However, their contributions will decline as the system load increases. Compared with the base case for Scenario 2, the energy contributions by gas and coal units, especially those supplied by gas units, will decrease as we reduce the system load.

Figure 49: Energy Portfolio in Wind Energy Scenarios

Figure 50: Wind/Non-Wind Energy in Load Scenarios

Figure 51: Production Cost in Load Scenarios

Figure 52: Energy Portfolio in Load Scenarios

Furthermore, the contribution of gas units to the energy portfolio will increase from 7% in the base case (Scenario 2) to 11% in Scenario 15 and 17% in Scenario 16 as we increase the system load, which means that the additional load is mainly supplied by gas units.

Figure 53 and Figure 54 show the hourly energy supplied by gas and coal units. In Figure 53, the energy supplied by gas units has increased as compared to that in Scenarios 13-14 especially at peak hours. In Scenario 13, gas units are mainly committed and dispatched at peak hours.

Figure 55 shows that the load variation would have the largest impact on the commitment and the dispatch of generating units as compared to the fluctuation in fuel price or wind energy production. The commitment based on Scenarios 13-14 shows that many of the existing units will never be committed as hourly loads are lowered. On the other hand, almost all existing units will be committed when the hourly loads are higher than the forecast in Scenarios 15-16. The results indicate that the load

management could introduce large incentives for improving the system operation bottlenecks and decreasing the operation costs.

Carbon Cost Sensitivity Analysis

Higher carbon cost can be used as an incentive for promoting the development of clean, efficient or environmentally friendly power generation portfolios [23]. The carbon cost data given in [23] is considered here as the low carbon cost scenario. The high carbon cost scenario would consider a carbon cost that is doubled. In this section, we consider wind energy sites with $CF \geq 40\%$ and $CF \geq 30\%$ for analyzing the following four scenarios.

Figure 53: Hourly Energy Provided by Gas Units in Load Scenarios

Figure 54: Hourly Energy Provided by Coal Units in Load Scenarios

Figure 55: Unit Commitment Result in Load Scenarios

- Scenario 17: Low carbon cost with a minimum 40% CF for wind energy sites
- Scenario 18: High carbon cost with a minimum 40% CF wind energy sites
- Scenario 19: Low carbon cost with a minimum 30% CF wind energy sites
- Scenario 20: High carbon cost with a minimum 30% CF wind energy sites

The variations in carbon cost will not change the wind energy contribution to the energy portfolio. The production costs for all four Scenarios are \$406.8 billion, \$638 billion, \$285.7 billion, and \$448 billion. Therefore, the total production costs with higher carbon cost would be much higher. For example, the average production cost at peak/off-peak load hours are \$89.5/MWh and \$71.7/MWh in Scenario 17, and \$140/MWh and \$113.5/MWh in Scenario 18. Figure 56 shows the energy portfolios in carbon cost Scenarios in which the high carbon cost will have a major impact on the energy supplied by gas and coal units. Since coal prices are lower than gas prices, the energy supplied by coal units does not change much in the low carbon cost Scenarios. The energy supplied by gas units increases from 9% in low carbon cost scenario (Scenario 17) to 29% in high carbon cost scenario (Scenario 18) while that of coal decreases from 45% to 25%. Similar results are obtained when we consider wind units with a minimum 30% CF. Figure 57 and Figure 58 show the hourly energy supplied by gas and coal units, which is consistent with that of Figure 56. Here, gas units would be committed and dispatched in most hours with high carbon costs.

Figure 56: Hourly Energy Portfolio in Carbon Cost Scenarios

Figure 57: Hourly Energy Provided by Gas Units in Carbon Cost Scenarios

Figure 58: Hourly Energy Provided by Coal Units in Carbon Cost Scenarios

Load Management by Introducing Load Shedding

As presented for Load Sensitivity Analysis, the hourly load variations would have a major impact on the WINS simulation results. In this section, we consider load shedding as an option to manage the system operation more efficiently at peak hours. For instance, if the hourly load is higher than 80% of annual peak load, we would set it at 80%. Three scenarios are considered as follows.

- Scenario 21: No wind energy is considered when the load shedding is applied
- Scenario 22: Wind energy with a minimum CF of 40% is considered when the load shedding is applied
- Scenario 23: Wind energy with a minimum CF of 30% is considered when the load shedding is applied

Figure 59 shows the energy production portfolios for the three load shedding Scenarios. Figure 60- Figure 62 show that the load shedding will alter the unit commitment as compared to those in Figure 45. Here, more gas units are turned off at peak hours when load shedding is applied. Here, there are about 1,200 gas units which would never be committed again when load shedding is considered as compared to those of the Scenarios 1, 2, and 3. These results are similar to those for load variation analysis given in Scenarios 13 and 14.

Figure 63 shows the hourly energy supplied by gas units in which the gas unit dispatch is lower because of the load shedding at peak hours. Load shedding has almost no impact on the hourly dispatch of coal units, as coal units are committed to serve the base load.

Figure 59: Energy Portfolio in Load Shedding Scenarios

Figure 60: Unit Commitment Result in Scenario 21

Figure 61: Unit Commitment Result in Scenario 22

Figure 62: Unit Commitment Result in Scenario 23

Figure 63: Hourly Energy Provided by Gas Units in Load Shedding Scenarios

C3. Conclusions

In this section, a comprehensive large-scale wind energy integration analysis is considered which is based on the 2030 load forecast in the Eastern Interconnection of the United States. Here, transmission constraints are not considered when studying the wind energy portfolios. The wind energy integration is studied based on the capacity factors of potential wind sites. Wind energy contributions to peak/off-peak annual production costs are studied based on the WINS simulation results. The sensitivity of fuel costs, wind energy production, hourly loads, carbon costs, and load management are analyzed in the wind energy integration Scenarios. The wind energy integration simulation results and their sensitivities are summarized in Table 1. Here, the contribution of wind energy to the 5 Scenarios is about 20% or higher.

Table 1: Summary of Simulation Results in All Scenarios

Scenario	Wind Capacity (GW)	Wind Generation (TWh)	Wind Contribution Percentage (%)	Production Cost (\$ Billion)	Average Production Cost (\$/MWh)
1	0	0	0	217.5	45.64
2	230.5	845.2	17.67	130.4	27.25
3	481.5	1,596	33.37	86.8	18.14
4	580	1,816	38	77	16.10
5	230.5	845.2	17.67	118.9	24.87
6	230.5	845.2	17.67	124.7	26.06
7	230.5	845.2	17.67	135.7	28.36
8	230.5	845.2	17.67	141.7	29.63
9	230.5	676.1	14.14	143.7	30.03
10	230.5	760.6	15.9	136.8	28.59
11	230.5	929.7	19.44	130.4	25.99
12	230.5	1014	21.20	124.3	24.80
13	230.5	845.2	22.07	64	16.73
14	230.5	845.2	19.62	91.6	21.27
15	230.5	845.2	16.29	178.5	34.65
16	230.5	845.2	15.12	245.9	44.54
17	230.5	845.2	17.67	406.8	84.97
18	230.5	845.2	17.67	638	133.3
19	481.5	1,596	17.67	285.7	69.68
20	481.5	1,596	17.67	448	93.59
21	0	0	0	208.7	44
22	230.5	845.2	17.81	123	25.9
23	481.5	1,596	33.53	80.6	16.97

D. Large-scale Analysis of 2018 Wind Energy Integration in the Eastern U.S. Interconnection

This section presents the hourly simulation results for the year 2018 with the large-scale wind energy integration in the Eastern Interconnection of the United States. A simulator referred to as WINS (Wind INtegration Simulator) is developed for this annual study. The wind energy integrations in the year 2018 are simulated using the hourly security-constrained unit commitment (SCUC) in WINS. The generation portfolio for supplying the hourly load in 2018 is developed with/without transmission network constraints. The sensitivities to the 2018 wind energy integration are carried out for fuel price, wind energy availability, load growth, carbon cost, and hourly load management strategies. The hourly production cost, generation credit, load payment, levelized congestion cost, LMPs, and wind energy contribution, are calculated and analyzed.

The U.S. Eastern Interconnection is the largest interconnection in the world with more than 5,000 generating units and about 45,000 transmission lines. The National Renewable Energy Laboratory (NREL) performed a study in 2008 to examine the impact of 20-30% wind energy integration in the Eastern Interconnection [15]. The western wind and solar integration study in 2007 examined the operational impact of 35% renewable energy penetration [16]. The impact of wind energy integration on power system operations is analyzed further in [17], [18]. An hourly unit commitment and economic dispatch model for analyzing large-scale power system operations was represented in [9]. A follow-up optimization-based security-constrained unit commitment (SCUC) model [6], [19] was presented in [20] which took into account the intermittency of wind power generation and transmission network constraints. A comprehensive adequacy analysis of energy production portfolio for 2030 was presented in [24]. The adequacy study in [24] did not consider transmission constraints as locations for the 2030 wind generation unit installations were not provided.

In this section, we focus on studying the 2018 large-scale wind energy integration in the Eastern Interconnection. The impact of large-scale wind energy integration on existing generation resources, production costs, LMPs, generation credits, load payments, transmission utilization, and wind energy deliverability are studied. The sensitivity of wind integration to fuel price, wind energy availability, load growth, carbon cost, and load management strategies is analyzed in this paper.

The rest of the section is organized as follows. Section II describes the proposed methodology, assumption and relevant evaluation metrics. Section III presents the wind energy integration study results for the Eastern Interconnections. The conclusions drawn from the study are provided in Section IV.

D1. Methodology for Wind Energy Integration

POMS (POWER Market Simulator) is an efficient decision tool for the day-ahead scheduling of large-scale power systems which has been utilized in transmission congestion analysis for the Eastern Interconnection in [21]. WINS (Wind INtegration Simulator) is the expansion of POMS in order to support the collaborative planning and implementation of the large-scale wind energy integration in the United States [24]. WINS applies SCUC to simulate the large-scale wind energy integration in the hourly power system operation. The application of WINS in this paper will analyze the impact of 2018 large-scale wind energy integration in the Eastern Interconnection.

Input Data

The generation and transmission data used in this study are based on the 2018 planning data in MTEP 08 (MISO Transmission Expansion Planning) [11]. We consider a 1.28% annual load growth which is based on the MTEP 08 assumptions. The hourly load distribution shown in Figure 64 is based on the MISO's hourly load profile in 2007.

Figure 64: Annual Hourly Load Profile

In Figure 64, peak loads appear in July and August. The power flow solution is used for calculating the hourly bus load distribution. The wind unit data for the 2018 WINS simulation are based on MTEP assumptions for 2018 and the hourly wind profiles are provided by the land-based time series wind simulation results [15]. The hourly wind profiles based on geographical locations are considered for wind generation units. Fuel prices are assumed to increase at an annual rate of 4% for oil and gas, 2% for coal, and 3% for nuclear fuel based on the fuel price given in 2008 [11].

Evaluation Metrics

The evaluation criteria and metrics used in this study are defined as follows.

Wind Energy Availability

The available wind energy is treated as dispatchable in WINS simulations. Here,

$$P_A = \sum_{t=1}^T \sum_{i=1}^{NW} p_i^{\max} w_{it} \quad (9)$$

where T represents the number of hours in a period (e.g., one year), NW represents the number of wind generators/farms, $p_i^{\max}$ is the nominal capacity of wind generator/farm i , w_{it} represents the wind power generation profile for generator/ farm i at time t , P_A represents the available wind energy for dispatch that is subject to transmission constraints.

Percentage of Wind Energy Contribution

This metric will evaluate the percentage of the wind energy contribution to the total energy for supplying the load in the power system.

$$= \frac{\text{Wind Energy}}{\text{Total Energy}} * 100 \% \quad (10)$$

Production Cost

$$\text{Production Cost} = \sum_{t=1}^T \sum_{i=1}^{NG} F_i(P_{i,t}) \quad (11)$$

where NG is the number of generators, $P_{i,t}$ is the dispatch of generator i at period t , $F_i(\cdot)$ is the production cost function of generator i .

Generation Credit

$$\text{Generation Credit} = \sum_{t=1}^T \sum_{i=1}^{NG} LMP_{i,t} * P_{i,t} \quad (12)$$

where $LMP_{i,t}$ is the LMP at generator bus i at period t .

Load Payment

$$\text{Load Payment} = \sum_{t=1}^T \sum_{j=1}^{ND} LMP_{j,t} * D_{j,t} \quad (13)$$

where ND is the number of load buses; $LMP_{j,t}$ represents the LMP of load bus j at period t ; $D_{j,t}$ represents the load at bus j at period t .

Transmission Utilization

$$= \frac{\sum_{t=1}^T |flow_{i,t}|}{T * Cap_i} * 100 \% \quad (14)$$

where $flow_{i,t}$ is the power flow on line i at period t ; Cap_i is the capacity of line i . The transmission utilization could also be calculated based on voltage level of transmission line.

Levelized Congestion Cost

This metric represents the levelized congestion cost.

$$= \frac{(\text{Load Payment} - \text{Generation Credit})}{\text{Load Payment}} * 100 \% \quad (15)$$

Transmitted Energy

$$= \sum_{i=1}^{NL} \sum_{t=1}^T |flow_{i,t}| \quad (16)$$

where NL represents the number of transmission lines. The transmitted energy is calculated for transmission lines grouped by voltage level (i.e., 230kV, 345kV, 500kV, and 765kV).

Levelized Energy Flow

$$\frac{\sum_{i=1}^{NL} \sum_{t=1}^T |flow_{i,t}|}{T * NL} \quad (17)$$

It is the averaged value of transmitted energy at a given voltage level.

D2. Numerical Results

In this section, we utilize WINS to simulate the 2018 wind integration in the Eastern Interconnection of the United States based on the methodology presented in section II.

Wind Integration Reference Cases

We simulate the hourly power system operation using WINS. Four scenarios are studied as follows.

- Scenario 1: All wind unit generation and transmission constraints are excluded in 2018
- Scenario 2: All wind unit generation is excluded in 2018 while transmission constraints are considered
- Scenario 3: The 2018 wind unit integration is considered while all transmission constraints are excluded
- Scenario 4: The 2018 wind unit integration and transmission constraints are considered

These four scenarios are discussed here.

Scenario 1: All wind unit generation and transmission constraints are excluded in 2018. This is the reference case in which the hourly loads will be served by fossil fuel and hydro units without considering any wind energy or transmission constraint in 2018. Figure 65 shows the hourly production cost which is \$92.25 billion per year with an average production cost of \$22.4/MWh. The production cost will not change linearly with hourly load fluctuations. Hydro units will have zero costs and be scheduled first to serve hourly loads or reserves; then cheaper units such as nuclear, coal, and large oil will be committed, and finally expensive units such as gas and oil will be committed to supply hourly loads. A higher production cost will occur at annual peak hours of 5,000–5,500 (i.e., July and August of 2018). The total production cost at peak hours (6 AM–10 PM) is \$74.04 billion and that at off-peak hours (11 PM–5 AM) is \$18.21 billion. The average production costs at peak/off-peak hours are \$24.2/MWh and \$17.3/MWh. The average production cost at peak load hours is higher when expensive generators are committed and dispatched.

Scenario 2: All wind unit generation is excluded in 2018 while transmission constraints are considered. Figure 66 shows the hourly production cost. Compared to Figure 65, the production cost is higher when transmission constraints are taken into account. The annual production cost is \$106.1 billion with an

average production cost of \$25.93/MWh. The production costs at peak and off-peak hours are \$84.1 billion and \$24.04 billion respectively. The average production costs at peak and off-peak hours are \$27.49/MWh and \$20.98/MWh respectively. Compared with Scenario 1, the production cost will increase by 15.06% when considering transmission constraints. The annual average LMPs based on the 2018 WINS simulation are shown in Figure 67. The annual average LMP in this scenario is \$61.77/MWh. Without any wind energy integration, LMPs are lower in the northwest and a small area in New England, and are higher in the New York region.

Figure 65: The 2018 Hourly Production Cost in Scenario 1

Figure 66: The 2018 Hourly Production Cost in Scenario 2

Figure 68 shows the monthly generation credit, load payment and production cost in Scenario 2. All three curves show a pattern similar to that of load profile in Figure 64. The incremental difference between the two curves shows the congestion cost. The annual generation credit, load payment and levelized congestion cost in 2018 are \$254.2 billion, \$270.7 billion, and 6.1% respectively.

Scenario 3: The 2018 wind unit integration is considered while all transmission constraints are excluded. Figure 69 shows the hourly production cost in Scenario 3. The annual production cost is \$77.95 billion with an average production cost of \$18.96/MWh. The production cost at peak and off-peak hours are \$62.67 and \$15.27 billion, respectively.

Figure 67: The 2018 Annual Average LMPs in Scenario 2

Figure 68: Monthly Generation Credit, Load Payment and Production Cost in Scenario 2

Figure 69, the average production costs at peak and off-peak hours are \$20.48/MWh and \$14.54/MWh. Compared to Scenario 1, the production cost is 15.5% lower after taking into account the wind energy integration because wind energy is treated as zero fuel cost generation resource.

Figure 70 shows the monthly wind energy in 2018 without considering transmission constraints. The wind energy resources are mostly available in spring and winter; however, peak loads occur in summer. January has the highest level of available wind energy of 27.8 TWh, which amounts to 7.9%, of the total energy. The wind energy is scarce in August when the highest level of annual load occurs. The available wind energy in August and the wind energy contribution (dispatch) to the total energy production

portfolio are 16.8 TWh and 4.1% respectively. The annual wind energy contribution to the energy production portfolio is 6.5%.

Figure 69: The 2018 Hourly Production Cost in Scenario 3

Figure 70: Monthly Available Wind Energy and its Contribution in Scenario 3

Scenario 4: The 2018 wind unit integration and transmission constraints are considered. Figure 71 shows the hourly production cost in which the annual production cost amounts to \$99.39 billion with an average production cost of \$24.18/MWh. The production costs at peak and off-peak hours are \$78.76 billion and \$20.63 billion respectively. The average production costs at peak and off-peak hours are \$25.74/MWh and \$19.63/MWh. Compared to Scenario 3, the production cost is 27.5% higher with the consideration of transmission constraints because transmission constraints would limit the flow from cheap and largely concentrated generation resources to load centers. Compared with the results in Scenario 2, the production cost is 6.8% lower when the wind energy is included. The production cost shows a higher sensitivity to the additional transmission constraints than to higher levels of wind energy integration.

Figure 72 shows the monthly wind energy in 2018 considering transmission constraints. December has the highest level of dispatched wind energy of 20.4 TWh, which amounts to 5.8% of the total energy supply. August represents the month with the least dispatched wind energy again (i.e., 13TWh and 3.2%). The annual wind energy contribution is 4.8%. Hence, about 26.1% of the available wind energy is curtailed due to transmission constraints.

Figure 73 represents the monthly available and dispatched wind energy in Scenario 4. Transmission constraints would limit the wind energy delivery to 73.88%. Here, 69.8TWh of wind energy is curtailed due to transmission congestion. The highest wind energy curtailment which is 7.46TWh occurs in January 2018.

Figure 71: The 2018 Hourly Production Cost in Scenario 4

Figure 72: Monthly Wind Energy and its Contribution in Scenario 4

Figure 73: The 2018 Monthly Available and Dispatched Wind Energy

Figure 74 shows the monthly generation credit, load payment and production cost in Scenario 4. The annual generation credit, load payment and levelized congestion cost are \$232.9 billion, \$253.1 billion, and 7.97% respectively. All three indicators in Figure 74 exhibit a pattern similar to that in Figure 68.

Figure 74: Monthly Generation Credit, Load Payment and Production Cost in Scenario 4

Compared to Scenario 2, generation credit and load payment quantities are reduced in this scenario when the wind energy is integrated; however, the levelized congestion cost increases from 6.1% to 7.97% which indicates that the wind integration will cause more congestion if there is no transmission expansion planning considered at the same time.

The annual average LMPs in Scenario 4 are shown in Figure 75. With the wind energy integration, LMPs in the northwest region drop which is due to rich wind energy resources in that region. The LMPs in New York, New England, and Florida are higher which demonstrate transmission congestion in those regions. The annual average LMP is \$54.49/MWh which is lower than that in Scenario 2. Figure 75 shows a higher

regional price increment than that in Figure 67 which is consistent with the higher levelized congestion cost in Scenario 4.

Figure 76 shows the energy production portfolio in all four Scenarios. Here, the gas unit production would increase as transmission constraints are considered. The energy supplied by coal units is decreased, when transmission constraints are taken into account, which is replaced by the energy supplied by gas or wind generation units.

Figure 75: Annual Average LMPs in Scenario 4

Figure 76: Energy Production Portfolios in Scenarios 1-4

Figure 77-Figure 79 show the energy supplied by gas, coal and wind units in four scenarios. With transmission constraints in place, more gas units are committed and dispatched, less coal units are dispatched, and wind energy is partly curtailed. These figures show that wind energy will partly replace the fossil energy production especially at off-peak hours when the wind energy is mostly available in the Eastern Interconnection.

Figure 80 depicts the transmission utilization (see (6)) in 2018 at various voltage levels with and without the wind energy integration. The 500kV transmission system shows the highest utilization level at both scenarios. The transmission utilization at 765kV level is lower than those at other voltage levels (i.e., 230kV, 345kV and 500kV). In Figure 80, the 765 kV transmission utilization with the wind energy integration is lower than that of other voltages which indicates that the wind energy is transmitted mostly at 500kV, 345kV, and 230kV transmission levels.

Figure 77: Hourly Energy Provided by Gas Units in Scenarios 1-4

Figure 78: Hourly Energy Provided by Coal Units in Scenarios 1-4

Figure 79: Hourly Wind Energy in Scenarios 2 and 4

Figure 80: Transmission Utilization with/without Wind Energy Integration

Figure 81 shows the sum of hourly transmitted energy in 2018. The 230kV transmission lines will transmit the most energy in the Eastern Interconnection. As shown in Figure 81, the 765kV transmission lines will only transmit a small portion of the total energy because there are fewer of such lines in the Eastern Interconnection. Figure 82 shows the levelized energy flow over a year in 2018. The largest levelized energy flow would be on 765kV transmission lines which is due to the higher capacity offered by such lines. In Figure 82, the levelized energy flow at the 500kV level is close to that in 765kV and higher than that in lower voltage levels (230kV, 345kV).

Figure 83 shows the annual commitment of existing power plants in 2018 in which red dots represent power plants in which at least one unit is committed for a minimum of one hour per year. Also, blue dots show the plants which will be off throughout the year as more wind energy is integrated in the Eastern Interconnection.

Sensitivity Analysis

There are several uncertain parameters in large-scale power systems including fuel price, wind speed, hourly load, and carbon tax, which could have major impacts on the large-scale wind energy integration.

These parameters may not be accurately forecasted for 2018. So, we apply sensitivity analyses to the WINS simulation results for Scenario 4 to study the impact of variations in such parameters on the wind energy integration. The WINS simulation results for Scenario 4 are treated as the base case.

Figure 81: Transmitted Energy in 2018 with/without Wind Integration

Figure 82: Levelized Energy Flow in 2018 with/without Wind Integration

Fuel Price Sensitivity

We apply the sensitivity analysis based on the WINS simulation results for Scenario 4. The wind energy integration was considered in transmission-constrained Eastern Interconnection. Generally, oil and gas prices are more volatile, while nuclear and coal prices are more settled. The following four scenarios are considered for analyzing the sensitivity of the WINS results to the fuel price volatility:

- Scenario 5: Oil and gas prices are 20% lower than the forecast
- Scenario 6: Oil and gas prices are 10% lower than the forecast
- Scenario 7: Oil and gas prices are 10% higher than the forecast
- Scenario 8: Oil and gas prices are 20% higher than the forecast

Figure 84 shows the production cost, generation credit, load payments and annual average LMP of four fuel price scenarios which are compared with the base case scenario results. The difference between load payments and generation credits represents the congestion cost in the Eastern Interconnection.

The production cost, generation credit, load payments, and LMPs in all scenarios will increase as fuel price goes up. Figure 85 shows the levelized congestion cost and wind energy contribution in the four scenarios.

Figure 83: Annual Unit Commitment in Scenarios 1-4

Figure 84: Economic Metrics in Fuel Price Scenarios

Figure 85: Levelized Congestion Cost and Wind Energy Contribution in Fuel Price Scenarios

In Figure 85, higher oil and gas prices would cause more transmission congestion which would limit the flow from cheaper and concentrated generation resources to load centers. In this case, the wind energy contribution will be slightly lower when fuel prices are higher. The reason is that more of large coal units will be used in such cases which could cause additional congestion for utilizing wind energy units. The fuel price volatility would have no impact on wind energy dispatch if transmission constraints are not taken into account [24].

Wind Energy Contribution Sensitivity Analysis

We implement the sensitivity analysis based the 2018 WINS simulation results given in section 0. Four scenarios are considered as follows.

- Scenario 9: Available wind energy is 20% lower
- Scenario 10: Available wind energy is 10% lower
- Scenario 11: Available wind energy is 10% higher
- Scenario 12: Available wind energy is 20% higher

Figure 86 shows the 2018 production cost, generation credit, load payments, and annual average LMP in the four wind production scenarios. As expected, the economic metrics will be more favorable as more wind energy is dispatched. Figure 87 shows the levelized congestion cost and wind energy contribution in the four wind energy production scenarios. Wind energy is assumed as a zero fuel cost resource, so the transmission system will try to deliver all the available wind energy to load centers. Hence, higher wind energy production scenarios could cause additional transmission congestion. Figure 87 shows a higher wind energy contribution to the energy production portfolio and higher congestion in the Eastern Interconnection as more wind energy is made available.

Figure 88 shows the energy production portfolio in four wind energy production scenarios. The energy produced by gas and coal units will decrease as additional wind energy is made available.

Figure 86: Economic Metrics for Available Wind Energy Scenarios

Load Variations Sensitivity Analysis

In this section, we carry out the load forecast sensitivity analysis based the 2018 load forecast. The WINS simulation results in section A4 are treated as base case. Four load sensitivity scenarios are studied as follows.

- Scenario 13: Total load is 5% lower than the forecast
- Scenario 14: Total load is 3% lower than the forecast
- Scenario 15: Total load is 3% higher than the forecast
- Scenario 16: Total load is 5% higher than the forecast

Figure 89 shows the production cost, generation credit, load payment, and annual average LMP in the four load sensitivity scenarios which are compared with the base case scenario.

Figure 87: Levelized Congestion Cost and Wind Contribution in Wind Energy Scenarios

Figure 88: Energy Production Portfolios in Wind Energy Production Scenarios

Figure 89: Economic Metrics in Load Scenarios

In Figure 89, as compared with Figure 84 and Figure 86, the system load variations will have a larger impact on production costs, generation credit, load payment, and LMPs. Also, generation credit and load payment demonstrate a higher sensitivity than the production cost to load variations.

Similar to the results in [24], Figure 90 shows that the system load variations will have the highest impact among the listed parameters on the commitment and dispatch of generating units. The unit commitment results based on Scenarios 13-14 shows that many generation units may never be committed again in 2018 as hourly loads drop. On the other hand, additional units are committed when the system load is higher. The results indicate that the hourly load management and demand response could introduce major alternatives for improving the system operation bottlenecks and enhancing the economic metrics of power systems in the Eastern Interconnection.

Figure 90: Annual Unit Commitment in Load Variation Scenarios

Figure 91 shows the levelized congestion cost and wind energy contribution in four load scenarios. The wind energy contribution will decrease as the system load increases because the additional load is served mainly by fossil generation units. The congestion cost for the four load scenarios are \$17.47 billion, \$18.05 billion, \$24.20 billion and \$28.03 billion respectively, which will increase with higher system loads. However, the levelized congestion cost in Figure 91 demonstrates a mixed result which is not increasing monotonically with the bus load level. The reason is that both generation credits and load payments are used to calculate the levelized congestion cost (7). However, generation credits and load payments which are determined by bus LMPs do not change uniformly with the bus load increments.

Figure 92 shows the energy contribution portfolio in the four load sensitivity scenarios. The cheaper nuclear, hydro, and wind generation units will supply much of the hourly load. However, their contributions will decline as load increases. Compared with the base case for Scenario 4, the energy

contribution portfolio by gas and coal units, especially those supplied by gas units, will decrease as we lower the system load.

Furthermore, the contribution of gas units to the energy production portfolio will increase from 10% in the base case (section A4) to 11.1% in Scenario 15 and 11.8% in Scenario 16 as we increase the system load. This observation shows that the additional load is mainly supplied by gas units.

Figure 91: Levelized Congestion Cost and Wind Contribution in Load Scenarios

Figure 92: Energy Production Portfolios in Load Scenarios

Carbon Cost Sensitivity Analysis

Additional carbon cost can be used as an incentive for promoting the development of clean, efficient, and environmentally-friendly generation resource [25]. Two Scenarios are studied in this section as follows.

- Scenario 17: Low Carbon cost at \$30/ton
- Scenario 18: High Carbon cost at \$60/ton

Figure 93 shows the production cost, generation credit and load payment in carbon cost scenarios. All three economic parameters will be much higher than those in the base case when carbon costs are applied. Figure 94 shows the levelized congestion cost, wind energy contribution and annual average LMP for the base scenario and two carbon cost scenarios. It is observed that the higher carbon cost will reduce the levelized congestion cost because higher carbon costs could reduce fuel price increments between cheap generation resources (coal) and expensive generation resources (gas). The annual average LMP could increase a lot when the carbon cost is higher.

Figure 93: Economic Factors in Carbon Cost Scenarios

Figure 94: Levelized Congestion Cost, Wind Contribution, and LMP in Carbon Cost Scenarios

Figure 95 shows the energy production portfolios in carbon cost scenarios in which the high carbon cost will have a major impact on the energy supplied by gas and coal units. Since coal prices are lower than gas prices, the energy supplied by coal units does not change much in the low carbon cost scenarios. The energy supplied by gas units increases from 10.5% in Scenario 17 to 12.2% in Scenario 18 while that of coal decreases from 50.3% to 48.6%. Additional wind energy will be dispatched when the high carbon

cost mitigates the transmission congestion. The wind energy contribution will be higher when the carbon cost increases. In this case, the wind energy contribution will increase from 4.8% in the base case (Scenario 4), to 4.9% in the low carbon cost scenario (Scenario 17) and 5.0% in the high carbon cost scenario (Scenario 18).

Figure 95: Energy Production Portfolios in Carbon Cost Scenarios

Load Management in 2018

As presented for load sensitivity analysis, the hourly load variations will have a major impact on the WINS simulation results. In this section, we consider load shedding at peak hours, i.e., if the hourly load at peak hour is higher than 80% of the annual peak load. In essence, the hourly load will be subject to demand response and set at 80% of annual peak load. One scenario is studied as follows.

- Scenario 19: Wind energy integration with possible load shedding

Figure 96 shows the production cost, generation credit and load payment for the base case and the load shedding scenario. All three economic factors will be lower with the load shedding implementation. Load shedding will almost have no impact on the hourly dispatch of coal units as coal units are committed to serve the base load. Figure 97 shows the energy production portfolios for the load shedding scenario. Figure 98 shows the hourly energy supplied by gas units in which the gas unit dispatch is lower due to load shedding at peak load hours.

Figure 96: Economic Factors in Load Shedding Scenario

Figure 97: Energy Production Portfolios in Load Shedding Scenario

Figure 98: Energy Provided by Load Shedding Scenario

Figure 99 shows that the load shedding will alter the unit commitment as compared to that of Scenario 4 shown in Figure 83. Here, additional gas units (1,700) are turned off at peak hours when the load shedding is applied.

Figure 99: Annual Unit Commitment in Scenario 19

D3. Conclusions

In this section, a comprehensive large-scale wind energy integration analysis is implemented based on the 2018 load forecast in the Eastern Interconnection of the United States. The wind energy integration with/without transmission constraints are studied and analyzed. The sensitivity of fuel price, wind energy production, load, carbon cost, and load shedding are implemented to study the impact of volatility of major parameters on the WINS simulation results. 19 Scenarios are studied and analyzed. The main observations based on the simulations are listed as follows:

- Production cost is more sensitive to transmission constraints than to wind energy integration.
- The location of wind energy integration could have an impact on the wind energy dispatch in the hourly generation portfolio.
- The addition of wind generation units at certain locations in the Eastern Interconnection may cause additional transmission congestion.
- In 2018, the replacement of coal units by wind energy at certain locations could mitigate transmission congestion.
- Wind energy is often available and can replace fossil energy at off-peak load hours. During certain seasons when wind is unavailable, wind energy supply could be replaced by fossil energy.
- In 2018, wind energy is transmitted mostly at 500kV, 345kV, and 230kV transmission levels while the 765kV transmission is utilized less by wind generation units.
- Higher costs for gas and oil will result in additional transmission congestion as power systems try to use cheaper coal units located centrally in fewer geographical spots. Such limited utilizations of centrally located resources may also limit the available dispatch of wind generating units.
- Higher levels of wind energy integration could result in higher levelized congestion costs when wind generation units, located at few geographical spots, try to supply a significant level of load.
- Carbon cost demonstrates the highest impact on the 2018 simulation results. Higher carbon costs will be instrumental in mitigating the regional transmission congestion in the Eastern Interconnection.
- Load forecast uncertainty will have a larger impact on the 2018 simulation results as compared to fluctuations in fuel prices or possible levels of wind energy integration.
- The levelized congestion cost may not increase monotonically with higher levels of bus loads.
- Peak load shaving will have a major impact on the commitment and dispatch of gas units because peak loads are mostly supplied by such units

The WINS simulation results shows that lowering the hourly volatility of load profile by introducing smart grid, additional distribution automation for the utilization of demand response, and the large-scale integration of wind energy and storage could lower the transmission congestion and improve the economics and the optimal operation of power systems in the Eastern Interconnection of the United States.

3.2 Wind Energy Education and Outreach

3.2.1 Wind Energy Training Facility Development

To fulfill our project tasks on workforce training and education, the project team erected a permanent facility at IIT for Workforce Training and Education on Sustainable Energy and Smart Grid. IIT secured funds from the State of Illinois to renovate the 16,000 sqft of space for establishing the proposed facility. The proposed facility will provide training on sustainable energy to various sectors including power industry employees, union workers, high school teachers, the public, and students through instructor-led and internet-based training courses. The floor plan of the training facility is shown in Figure 100.

Figure 100: Floor plan of the training facility

A. Robert W. Galvin Center for Electricity Innovation

In 2010, Illinois Institute of Technology launched the Robert W. Galvin Center for Electricity Innovation, whose mission is to pursue groundbreaking work in the generation, transmission, distribution, management and consumption of electricity. The Galvin Center brings together faculty, students, researchers, industry, government, innovators, and entrepreneurs to collaborate to improve the reliability, security and efficiency of the electric grid and overcome obstacles to the national adoption

and implementation of the Smart Grid. The center brings together researchers, industry, government, and innovators to “plug-in” to IIT’s smart microgrid, research laboratories and technology park, creating a hub – or sandbox – for new innovations in advanced grid technology. IIT and the Galvin Center have become leaders of the Smart Grid technological revolution by building the first ever fully-functional Perfect Power system, a smart grid demonstration project, on IIT’s Main Campus in Chicago.

- **Pioneering Perfect Power** – IIT and the Galvin Center have become leaders of the Smart Grid technological revolution by building the first ever fully-functional Perfect Power system, a smart grid demonstration project, on IIT’s Main Campus in Chicago. The project eliminates blackouts, allows for “islanding” of the campus from the broader grid, integration of renewable energy and battery storage, and introduction of advanced smart buildings technology for energy efficiency. The Galvin Center leadership is working with entities across the world to replicate and scale the microgrid model for communities, military bases, corporate parks, sports facilities, and other universities.
- **IIT “Living Laboratory” for clean tech** – IIT and the Galvin Center have transformed the IIT campus into a “Living Laboratory” for energy projects. This approach integrates advanced new technology demonstrations in visible locations with hands-on research and education opportunities for students and faculty. The technologies demonstrated as part of this approach include: building automation and control, master controller systems, rooftop solar, a wind turbine, electric vehicle charging stations, and large-scale battery storage.
- **Smart Grid Workforce Training** – The Galvin Center recently completed construction of a state-of-the-art facility to house its Smart Grid Education and Workforce Training Center. The 16,000-square-foot center contains offices, exhibition rooms, classrooms and student workrooms, acting as a living lab for Smart Grid and microgrid technology and education. The Center is engaging thousands of workers and students to accelerating the adoption of energy efficiency, renewable energy, and smart grid technologies across the world.
- **IIT Wind Consortium** – In 2009, the Galvin Center leadership was awarded a \$9 million grant from the U.S. Department of Energy to establish a University-Industry Consortium for wind energy research and education. The Galvin Center leadership was also awarded \$750,000 from DOE to study wind integration into the U.S. grid. The Consortium has engaged 50 companies and 8 universities in the U.S. and around the world in technological advances related to the next generation of wind energy manufacturing.
- **Illinois Smart Grid Regional Innovation Cluster** – IIT is leading the development of an innovation platform for Smart Grid technology that was awarded \$1.5 million from the Small Business Administration. The Center is providing technical and business support to speed new Smart Grid technologies on the path to commercialization in Illinois.
- **Global Smart Grid Technology Partnership** – In 2011, the Galvin Center launched the Illinois-Korea Smart Grid R&D Collaboration, a joint international collaboration to accelerate the technological

development of smart grid in Chicago. The Korea industries have awarded the Galvin Center a \$2.5 million project for the installation of phasor measurement units (PMUs) at the IIT's microgrid. This partnership is intended to stimulate new interactions among stakeholders in Chicago and Korea and bring additional manufacturing jobs to Illinois.

The Galvin Center has led more than \$40 million in projects with funding from the government and private sectors for research and development in microgrids, smart grid technology, and sustainable energy. All of these projects have been completed on-time and within budget. IIT has designated the campus as a "Living Laboratory" for smart grid, microgrid, and other energy technologies, training facility staff and other personnel on the operation, maintenance and repair of these and new technologies. This innovative partnership between facility managers and a research unit is one of the first of its kind in the U.S.

State-of-the-Art Facility. In January 2012, the Galvin Center completed and moved into a new, state-of-the-art facility designed to house its Smart Grid, microgrid and energy research, demonstration and education activities. Located on the 16th floor of the IIT Tower, the 16,000-square-foot center contains offices, exhibition rooms, classrooms and student workrooms, acting as a hands-on experience center for Smart Grid, microgrid and energy technology and education. The \$3 million project was funded by the State of Illinois, U.S. Department of Energy and IIT.

Figure 101: State-of-the-art facility at the Galvin Center

Perfect Power System. In 2011, the Galvin Center completed the world's first Perfect Power System on its main campus in Chicago. Inspired by the leadership of Bob Galvin, the center's premier project is the development of the nation's first Perfect Power microgrid at IIT. When fully completed in the next year, the \$14 million project has equipped IIT's microgrid with a new high-reliability distribution system for enhancing reliability, the ability to integrate new sustainable energy sources (roof-top solar panels, wind generation units, flow batteries and charging stations for electric vehicles), and smart building automation technology (building controllers, Zigbee sensors, controllable loads) for energy efficiency and demand response. The high-reliability distribution system was completed in 2011, allowing IIT to eliminate blackouts.

Figure 102: IIT Perfect Power System overview

Electric Vehicle Charging Stations. In 2012, the Galvin Center completed the installation of 7 Electric Vehicle charging stations on its main campus in Chicago. The installation includes 6 “Level 2” charging stations for 5-hour EV charging, and one of the first DC Quick Charge EV charging stations in the country, which can charge a vehicle in 20-30 minutes. The \$120,000 project was funded by the U.S. Department of Energy and private partners.

Figure 103: IIT Electric Vehicle Charging Stations

Rooftop Solar. In 2012, the Galvin Center completed the installation of a 60 kW of rooftop solar on two campus buildings: Siegel Hall and Stuart Building. The \$440,000 project was funded by the U.S. Department of Energy, the State of Illinois and private partners.

Figure 104: IIT Rooftop Solar Installation

Large-Scale Battery Storage. In 2012, the Galvin Center completed the installation of a next-generation smart grid-capable large-scale battery project on IIT's microgrid testbed for demonstration and evaluation. Produced by the ZBB Corporation, the 500 kWh zinc-bromide flow battery will be the first-of-its-kind in the U.S., demonstrating the ability of microgrid systems to island, coordinate peak load management and peak shaving, and provide backup power. The \$1,000,000 project was funded by the U.S. Department of Energy, with cost-share provided by ZBB Corporation.

Figure 105: IIT Large-scale Battery Storage

B. Situation Awareness at Control Center: e-terravision

e-terravision is a system that was jointly developed by Alstom Grid with major utilities, a situation awareness expert, and in partnership with Microsoft for the use of the latest graphics technology. This system addresses the need for enhanced situation awareness in control centers.

e-terravision is a relatively new product suite whose main purpose is to supplement control rooms with higher-level decision support capability using visualizations for improving situation awareness. e-

terravision complements Energy Management System (EMS) and Market Management System (MMS) user interfaces. The goals for e-terravision are to implement a control center “situation awareness” framework and tools to:

- Mitigate operational risks
- Present wide-area and “big picture” views of the system
- Assist in ensuring system reliability
- Increase the productivity of control center resources

With e-terravision, control room, operators can:

- Monitor the transmission network with large overviews,
- Assess the grid’s reliability using advanced visualization,
- Perform predictive analysis, and
- Prioritize corrective actions.

Figure 106: Enhanced Situation Awareness in Control Centers

3.2.2 Wind Energy Course Development

A. Elements of Sustainable Energy at Illinois Institute of Technology

This course covers cross-disciplinary subjects on sustainable energy that relate to energy generation, transmission, distribution, and delivery as well as theories, technologies, design, policies, and integration

of sustainable energy. Topics include wind energy, solar energy, biomass, hydro, nuclear energy, and ocean energy. Focus will be on the integration of sustainable energy into the electric power grid, the impact of sustainable energy on electricity market operation, and the environmental impact of sustainable energy. The syllabus of this course is as follows.

B. Elements of Smart Grid at Illinois Institute of Technology

This course covers cross-disciplinary subjects on smart grid that relates to energy generation, transmission, distribution, and delivery as well as theories, technologies, design, policies, and implementation of smart grid. Topics include: smart sensing, communication, and control in energy systems; advanced metering infrastructure; energy management in buildings and home automation; smart grid applications to plug-in vehicles and low-carbon transportation alternatives; cyber and physical security systems; microgrids and distributed energy resources; demand response and real-time pricing; and intelligent and outage management systems. The syllabus of this course is as follows.

ECE 580 – Elements of Sustainable Energy, Fall 2010**Class Meetings:** 6:25-9:05 PM, Tuesday; Location: Wishnick Hall 115**Instructor:** Zuyi Li, PHD; Office: Room 223, Siegel Hall; Phone: (312) 567-5259; E-mail: lizu@iit.edu**Office hours:** 3-5PM, Tuesday, or by appointment.**Textbook:** No textbook is required**References**

- Gilbert Masters, Renewable and Efficient Electric Power Systems, Wiley, 2004.
- Leon Freris and David Infield, Renewable Energy in Power Systems, Wiley, 2008.
- U.S. Department of Energy, 20% Wind Energy by 2030, 2008.
- Selected papers from the IEEE and other journal publications and conference proceedings.

Grading

Homework: 50%

Exam: 20%

Research Paper: 30%

The exam is open-book and open-notes.

A: [85, 100]

B: [70, 85)

C: [60, 70)

E: [0, 60)

Course Schedules (subject to change)

Week 1	August 24	Introduction to Sustainable Energy
Week 2	August 31	Renewable Energy Technologies
Week 3	September 7	Variability of Renewable Energy
Week 4	September 14	Operational Issues of Renewable Energy (1)
Week 5	September 21	Operational Issues of Renewable Energy (2)
Week 6	September 28	Operational Issues of Renewable Energy (3)
Week 7	October 5	Planning Issues of Renewable Energy (1)
Week 8	October 12	Planning Issues of Renewable Energy (2)
Week 9	October 19	Planning Issues of Renewable Energy (3)
Week 10	October 26	Exam
Week 11	November 2	Other Issues Related to Sustainable Energy (1)
Week 12	November 9	Other Issues Related to Sustainable Energy (2)
Week 13	November 16	Other Issues Related to Sustainable Energy (3) Presentation of Research Paper (1)
Week 14	November 23	Presentation of Research Paper (2)
Week 15	November 30	Presentation of Research Paper (3)
Week 16	Final Exam Week	Research Paper Due

ECE 581 – Elements of Smart Grid, Fall 2010

Class: W-F 10:00- 11:15 am; Location: PH 131

Instructor: Professor Mohammad Shahidehpour, 222 SH, (312) 567-5737, ms@iit.edu

Office Hours: W and F 2-3 pm (or by appointment)

Grading: HW: 30%, Class participation: 10%, Midterm exam: 25%, Final: 35%

Homework Assignments: Students must review the power point slides before attending the lecture. I will distribute eight technical papers throughout the semester. Students are required to summarize each paper and write a review on the paper within two weeks. Midterm and final exams will include questions on class presentations and the technical papers. Exams will be open book.

Course Schedules

August 25 Mohammad Shahidehpour Professor, IIT

August 27 Steve Blume President, Applied Professional Training

September 1 Mohammad Shahidehpour Professor, IIT

September 3 Christian Herzog President, Software Technologies Group

September 8 John Kelly President, IPS Corporation

September 10 Al Stevens Director, S&C Electric Company

September 15 Ken Zdunek Professor, IIT

September 17 Tony Metke Distinguished Member of Technical Staff, Motorola

September 22 Kui Ren Professor, IIT

September 24 Jim Gagnard President, Smart Signal

September 29 Terry Schuster Director, Energy Connect

September 30 Mohammad Shahidehpour Wind Energy Conference

October 1 Mohammad Shahidehpour Perfect Power Presentation

October 6 Robert Holz Director, Smart Lab

October 8 Tom Hulsebosch West Monroe Partners

October 13 Alireza Khaligh Professor, IIT

October 15 Joshua Milberg Deputy Commissioner, City of Chicago

October 20 Ali Emadi Professor, IIT

October 22 Midterm Exam Midterm Exam

October 27 Paul McCoy President, TransElect

October 29 Tim Stojka CEO, Fast Heat

November 3 Yang Xu Professor, IIT

November 5 Terence Donnelly Senior VP, ComEd

November 10 Mohammad Shahidehpour Professor, IIT

November 12 Mark Pruitt Director, Illinois Power Agency

November 17 Kevin Dennis VP, ZBB Energy

November 19 Tom Overbye Professor, University of Illinois

December 1 Farrokh Rahimi VP, Open Access Technology International

December 3 Mohammad Shahidehpour Professor, IIT

Final Exam

4. Accomplishments

4.1 Award

- 1) Dr. Mohammad Shahidehpour received the IEEE Power and Energy Society Outstanding Power Engineering Educator Award (For leadership in the power engineering field and contributions to the engineering profession and engineering education) in 2012.
- 2) Dr. Mohammad Shahidehpour Technologist of the Year Award from the Illinois Technology Association (Presented to the individual whose talent has championed true technology innovation, either through new application of existing technology or the development of technology to achieve a truly unique product or service) in 2011
- 3) Dr. Mohammad Shahidehpour received the Outstanding Engineer Award, IEEE Power and Energy Society Chicago Chapter (for significant leadership and contributions towards IIT's Prefect power microgrid, the IIT's wind consortium, and the IIT's Smart Grid Education and Workforce Development) in 2011
- 4) In the 27th Annual Conference of the ECEDHA (Electrical and Computer Engineering Department Heads Association) on March 14, 2011, IIT's Center for Electricity Innovation, the principal unit performing this DOE project, won the Innovation Award from ECEDHA (single award) for establishing the Illinois Institute of Technology as a global leader in microgrids, smart grid technology, and sustainable energy. Below is a copy of the citation.
- 5) Dr. Mohammad Shahidehpour received IIT's First Research Leadership Award (in Recognition of Outstanding Accomplishments in Developing Strong Research Collaborations and Large Scale Research Projects) in 2010
- 6) Dr. Mohammad Shahidehpour received the Distinguished Service Award, IEEE Power &Energy Society (For serving as General Chair of the 2012 IEEE Innovative Smart Grid Conference)
- 7) Dr. Mohammad Shahidehpour received the Distinguished Service Award, IEEE Power & Energy Society (For serving as VP of Publications) in 2011

ECEDHA

Electrical and Computer Engineering Department Heads Association

2010 Innovative Program Award

presented to

Mohammad Shahidehpour
Illinois Institute of Technology

for the Center for Electricity Innovation
Establishing the Illinois Institute of Technology as a global leader in microgrids,
smart grid technology, and sustainable energy

Presented at the 27th Annual Conference of the ECEDHA

Ed Schlosinger
ECEDHA President
2010-2011

Phoenix, Arizona
March 14, 2011

4.2 List of Presentations

- 1) Acciona and Its Support for Consortium, Frank Bristol, Acciona, September 30, 2010, Illinois Institute of Technology
- 2) Wind Energy Class Offering at the Illinois Institute of Technology, Zuyi Li, Illinois Institute of Technology, September 30, 2010, Illinois Institute of Technology
- 3) Smart Transmission Making a Smart Grid Smarter, Paul McCoy, Trans-Elect Development Company, September 30, 2010, Illinois Institute of Technology
- 4) A Big Step Toward Energy Independence, Paul McCoy, Atlantic Wind Connection, July 20, 2011, Illinois Institute of Technology
- 5) Integrating Midwest Wind Energy into Southeast Electricity Markets, Aidan Tuohy, Electric Power Research Institute

- 6) Advanced Wind Integration Study, Zuyi Li, Illinois Institute of Technology, July 20, 2011, Illinois Institute of Technology
- 7) Market Clearing under Uncertainty, Antonio J. Conejo, University of Castilla – La Mancha, Spain, January 2011, at Illinois Institute of Technology
- 8) Integrating Non-dispatchable Producers (Wind) in Electricity Markets, Antonio J. Conejo, University of Castilla – La Mancha, Spain, January 2011, at Illinois Institute of Technology
- 9) Large-Scale Simulation of Electric Power Systems for Wind Integration, PhD Final Defense, Wei Tian, Illinois Institute of Technology, August 2011

4.3 List of Theses

- 1) Mohammad Khodayar, Coordination of Storage with Renewable Energy Resources in Power Systems, Illinois Institute of Technology, July 2012

Abstract: The ever-increasing penetration of variable wind energy in power systems affects the hourly dispatch of thermal power generation in electricity markets. The coordination of wind power generation units with pumped-storage hydro (PS) generation could relieve the variability of wind energy and increase its hourly dispatchability. Chapter 2 proposes a coordination methodology for wind and pumped-storage hydro (PS) units in the day-ahead operation planning of power systems. With coordination, the PS unit can offset intrahour wind energy imbalances (i.e., deviations from hourly schedules) and minimize wind energy curtailments. The variability of wind energy, which makes it non-dispatchable and difficult to control, could bring significant challenges to power system operators. In Chapter 3, the wind-PS coordination is based on the application of stochastic security-constrained unit commitment (Stochastic SCUC). In this study, the hourly bus-level coordinated scheduling of wind energy and PS is compared with the system-level coordinated operation strategies in the day-ahead scheduling of power systems.

From GENCO point of view volatility of wind generation can reduce the profit in day-ahead market by imposing potential imbalance charges. In Chapter 4 day-ahead price-based scheduling strategy for the coordination of wind and storage units in a generating company (GENCO) is proposed. The proposed strategy is based on the stochastic price-based unit commitment (PBUC) which considers volatilities in day-ahead intra-hour market prices and wind power generation when scheduling wind and storage units. The proposed approach firms up the hourly sum of wind and storage unit generation, and mitigate potential wind energy imbalance charges for GENCOs in electricity markets. Although the proposed approach applies to any kind of storage, we consider the pumped-storage hydro (PS) unit in this study.

The increased utilization of PEVs, which consume electricity rather than fossil fuel for driving, offers unique economic and environmental opportunities, and brings out new challenges to electric power

system operation and planning. The storage capability of PEVs could help power systems mitigate the variability of renewable energy sources and reduce grid operation costs. Vehicle-to-grid (V2G) enables PEVs to have bi-directional power flows once they are connected to the grid, i.e., they can either inject power to, and draw power from, the grid which adds further complexity to power system operations. PEVs signify customers' random behavior when considering their driving patterns, locational energy requirements, topological grid interconnections, and other constraints imposed by the consumers. The proposed approach in Chapter 5 evaluates the effect of integrating a large number of electric vehicles (EVs) on power grid operation and control. The EV fleets could serve as electricity load when drawing energy from the grid and as energy storage (vehicle-to-grid) when delivering energy to the grid. Two operating modes for EV fleets were considered which are consumer-controlled and grid-controlled. The power grid generation mix represents a multitude of units including thermal, hydro, and wind. In this chapter, the impact of EV battery utilization on offsetting the hourly intermittency of wind generation units in transmission-constrained power grids is evaluated. Moreover, the effect of charging/discharging schedule of EV batteries and consumer driving requirements on the optimal hourly transmission-constrained commitment and dispatch of generation units in the day-ahead scheduling is investigated. The hourly solution of the proposed method will minimize the cost of supplying the hourly load while satisfying the temporal constraints of individual components in power grids.

In Chapter 6 the coordinated integration of aggregated plug-in electric vehicle (PEV) fleets and renewable energy sources (wind energy) in power systems is studied by stochastic security-constrained unit commitment (Stochastic SCUC) model, which minimizes the expected grid operation cost while considering the random behavior of the many PEVs. PEVs are mobile and distributed devices with deferrable options for the supply/utilization of energy at various times and locations. Numerical tests demonstrate the effectiveness of the proposed approach for analyzing the impact of PEVs on the grid operation cost and hourly wind energy dispatch.

Microgrid is composed of distributed energy resources (DER) including distributed generation (DG), controllable loads, and storage. Microgrids could satisfy hourly demands economically according to power quality and reliability (PQR) requirements. Other objectives in a microgrid could include the reduction in distribution system losses and increase in the efficiency of the combined heat and power (CHP) supply. In Chapter 7, the role of high reliability distribution system (HRDS) in microgrid operations is evaluated. HRDS, which offers a higher operation reliability and fewer outages in microgrids, is applied to looped networks in distribution systems. The storage system would enhance the microgrid reliability while offering hourly ancillary services and demand response for reducing operation costs. The HRDS implemented at Illinois Institute of Technology (IIT) is used as a case study along with the local DER to increase the load point reliability and decrease the operation cost of the microgrid. The outage frequency and duration indices are measured at the microgrid level and the customer level, and the potential system enhancements are discussed at the IIT microgrid.

2) Kaveh Aflaki, Large Scale Integration of Sustainable Energy and Congestion Management in the Western Interconnection, Illinois Institute of Technology, July 2012

Abstract: Sustainable energy is the maintainable type of energy that meets the needs of the present for generating electricity without compromising the ability of future generations to meet their needs. In electricity generation, implementing sustainable energy sources for generating electricity is one of the critical and the most inevitable challenging topics. Sustainable energy resources for generating electricity which in some cases called renewable energy are wind, solar, hydro, and geothermal energy. Furthermore, sustainable energy is a term which is used for techniques to improve energy efficiency as well in some of the researches. Wind and solar energy are the fastest growing sustainable energy sources that can be used as alternatives to the pollution generated from other electricity production in the United States. When the Department of Energy, (DOE), announced its vision for a 20% wind and a 5% solar energy contribution to electricity generation by the year 2030 in the United States, most of the research centers, national laboratories, and universities shifted their priorities to do research on different aspects of wind and solar energy. Furthermore, greenhouse gas reduction led to Carbon Tax policies for pollution generating units, which boosted the combined efforts at wind and solar energy research as well as their implementation. The DOE, as well as different recovery acts enacted at the state level, emphasize the expectation of an increased level of wind, solar, and other renewable energy sources so that together they will provide 30% of the total U.S. electricity consumed nationwide by 2030. The utilization of sustainable energy sources like wind and solar energy will offer great socioeconomic benefits reductions in power plant emissions and the supply of zero cost electricity.

Large scale wind and solar energy integration to the bulk grid could introduce inevitable challenges to regional transmission and generation systems. The most important challenges for transmission system are the congestion analysis of the grid and planning for transmission expansion to transfer the zero cost generated electricity to different electricity markets. The other big challenge is competition of current generation units in the electricity market. Current generators in the grid based on where they are located want to compete and participate in the electricity markets. However, generators like coal units are generating tons of carbon dioxide. Coming policies regarding carbon tax and adding high level of sustainable sources to the bulk grid force them to retire. This thesis addresses the congestion identification and management, optimization, simulation and analysis of large scale electric power systems in different scenarios for high level of wind and solar energy integration and related transmission expansion issues.

This thesis brings a new method used to study transmission congestions in Western Interconnection of the United States. The process involved Security-Constrained Unit Commitment (SCUC) formulation applying its results for analysis of transmission congestion. The proposed SCUC tool for these analyses is referred to as Power Market Simulator, POMS, which is being developed in the Electrical and Computer Engineering Department of Illinois Institute of Technology. With the help of POMS, all congested branches are shown on a Geographical Information System, GIS, synchronized map. In next step all congested branches are compared with two results; the National Electric Transmission Congestion Study, NETCS published by the U.S. Department of Energy in December 2009; and the annual 2009 report of

Transmission Expansion Planning Policy committee, TEPPC, of Western Electricity Coordinating Council, WECC. Moreover, POMS allowed calculation of LMP for the entire WECC which was not considered in the report of NETCS.

This thesis presents results and findings in simulation of the system operation in the Western Interconnection of the United States with the inclusion of large-scale wind and solar power penetration into the grid for year 2030. For this study, a simulator is developed and implemented as a Wind Integration Simulator, WINS, in the Galvin Center for Electricity Innovation at the Illinois Institute of Technology (IIT). In WINS high level wind and solar energy with the forecasted wind and solar time series profiles were added to the bulk grid of WECC. Their impact on different existing types of generation plants is studied. WINS utilize Security-Constrained Unit Commitment (SCUC) to simulate the wind and solar energy penetration. The bulk system of western interconnection which is coordinated and promoted by WECC and is the second largest bulk grid in the three interconnections of the North America primarily used as a case study for this thesis. High transmission capacities assumed accessible to all generation resources that mean the transmission constraints are relaxed. Moreover, none of the current bilateral contracts for WECC are considered. WINS uses hourly forecasted profiles of the wind and solar energy for an economic dispatch of the units. The production costs, wind and solar power contributions in peak load hours and off-peak load hours are also calculated and studied for this thesis. The sensitivity of the fuel prices, wind turbine power output, load volatility and demand side management as well as carbon tax are analyzed in different possible scenarios.

In order to incorporate large scale of wind and solar energy into a bulk electricity grid footprint, planned transmission expansion showed need to take place. Transmission expansion reduces grid congestion and balances Locational Marginal Prices (LMP). This thesis explores the advancements in high-performance computing and visual analytics of economic-based transmission expansion in the Western Electricity Coordinating Council (WECC). This expansion is based on 2018 and 2029 forecasted data. An advanced congestion analysis is proposed using WINS for optimization, simulation and visualization of the results. It identifies transmission congestions and different area average bus LMP, and expands the transmission system while accommodating large scale wind and solar energy to achieve the Department of Energy's (DOE) renewable energy vision for year 2030. In wind and solar integration studies, WINS applies annual wind energy forecast data as individual generation profile curves for each defined wind and solar farm units in the Security-Constrained Unit Commitment (SCUC) problem. WINS applies the SCUC engine to solve optimization issues caused by network constraints. Results are visualized on the Geographical Information System (GIS) format map. An iterative transmission expansion analysis, based on the average marginal prices for each area, is used to identify the minimum WECC transmission lines required. By using WINS, the transmission congestion and transmission expansion analysis results are visualized on a map of North America.

- 3) Jie Li, Optimal Behavior Modeling and Analysis of Electricity Market Participants, Illinois Institute of Technology, May 2012

Abstract: In restructured electricity power markets, competition among market participants is a key issue of concern for both the ISO (Independent System Operator) and the market participants themselves. This dissertation analyzes the market behavior of both the generation side and demand side participants, and provides solution guidelines for devising effective competition strategies for market players' profit maximization objectives.

Generation side is the most competitive part in the electricity market with the unbundling of generation, transmission and distribution. Acting as self-interested entities, GENCOs (Generation Companies) are seeking effective and computationally efficient methodology for generation resource scheduling, while keeping its financial risks at acceptable levels when constituting bidding strategies. To help GENCOs achieve such goal, this dissertation propose a game theory based supply function like bidding model to construct the optimal bidding strategies in both energy and ancillary service markets.

On the demand side, demand participation in the electricity market has already been advocated for a long time for its benefit to the entire market and the society as a whole. This dissertation focuses on a specific large electricity consumer type – Internet Data Center (IDC). By analyzing the unique energy consumption pattern for different IDC applications, this dissertation devises effective electric demand management solution, and quantifies the demand response effect of IDC on the electricity market.

- 4) Yanling Yuan, Load Redistribution Attacks and Protection Strategy in Electric Power Systems, Illinois Institute of Technology, May 2012

Abstract: Electric power systems have evolved over the past century to the largest and the most complex cyber-physical systems. With the development of Smart Grid, cyber security has becoming an area of growing concern. The well functioning of state estimation, which provides faithful estimation of the real-time physical system information based on a large number of distributed meter measurements, is of paramount importance for maintain stable and secure system operation. False data injection attack, which is against state estimation through SCADA network, has recently attracted wide research interest. This paper further develops the concept of load redistribution attack, a special type of false data injection attack. The physical and market impact of load redistribution (LR) attacks are quantitatively analyzed in this thesis.

Since LR attacks can successfully bypass bad data detection and manipulate the state estimation outcome, Security constrained economic dispatch (SCED) based on the false estimated state would lead the system into a false secure and optimal operating state. The physical damaging effects of LR attacks are analyzed thoroughly in this thesis. Based on the damaging effect analysis, two different attacking goals are differentiated from the adversary's perspective, i.e., immediate attacking goal and delayed attacking goal. For the immediate attacking goal, a max-min attacker-defender model is proposed to identify the most damaging immediate LR attack. Different algorithms are used to solve this bi-level optimization problem. For the delayed attacking goal, a tri-level model is proposed and solved to

identity the most damaging delayed LR attack. This paper is a first attempt to formalize the physic impact of false data injection attacks on the system operation and control.

Recent research examined the possible economic impact of false data injection attacks against state estimation in electric power market operations. False data injection attacks, by manipulating the state estimation, can manipulate the nodal price of ex-post real-time market. In conjunction with virtual bidding, these integrity attacks can lead to consistent financial profit for the attacker. This thesis further this study by quantifying the economic impact of LR attacks to the market operation of power systems. A convex model is developed under the mechanism of virtual bidding to compute the optimal injection of LR attack and the optimal selection of nodal pairs for virtual power, which gains the most profit from the attackers' perspective.

This thesis investigates the construction of LR attacks against AC state estimation. A practical procedure is proposed to construct an effective LR attack that can bypass the bad data detection (BDD) in AC state estimation, while having great damaging effect to the physical and market operation of power systems.

The quantitative impact analysis of LR attacks provides an in-depth insight on effective attack prevention with limited protection resource budget. This thesis also proposes the theory and criterion of protecting the system from the damage of a specific LR attack, considering the existence of stochastic measurement error. Effective protection strategies can then be designed to defeat the attacker's attempt.

- 5) Wei Tian, Large-scale Simulation of Electric Power Systems for Wind Integration, Illinois Institute of Technology, July 2011

Abstract: The utilization of wind energy will pose great socioeconomic benefits with reductions in power plant emissions and the supply of zero cost energy; however, large-scale wind energy integration could introduce inevitable challenges to regional transmission systems and hourly system operations. This thesis addresses the congestion identification, simulation and analysis of large-scale electric power systems in different scenarios, large-scale wind energy integration and related transmission expansion issues.

A methodology based on the security-constrained unit commitment (SCUC) is applied to analyze the transmission congestions in the Eastern Interconnection of the United States. The identified congestions are visualized along with the Geographical Information System (GIS) data and compared with the results in National Electric Transmission Congestion Study (NETCS) published by the Department of Energy of the United States in 2006. The study also provides the locational marginal price (LMP) information in the Eastern Interconnection, which is not available in the NETCS report.

This thesis implements a comprehensive simulation and scenario analysis of the Illinois electric power system for the year 2011. Possible scenarios representing electrical load sensitivities to economic growth, fuel price variations, and the impact of carbon cost, are studied.

This thesis presents the hourly simulation results for the large-scale wind energy integration in the Eastern Interconnection of the United States. An hourly unit commitment is applied for the simulation of the economics of wind energy integration in the year 2030. The energy portfolio for supplying the hourly load in 2030 is developed based on wind integration levels. The sensitivities of fuel price, wind energy quantity, load forecast, carbon cost, and load management to the proposed 2030 wind integration are studied.

This thesis identifies transmission congestions and expands the existing transmission system in the Eastern Interconnection of the United States for accommodating a large-scale integration of wind energy. Violated transmission flows which would cause the infeasibility of hourly SCUC are identified. An iterative transmission expansion analysis is implemented to identify the minimum required additions to the Eastern Interconnection for mitigating hourly transmission congestions.

- 6) Amin Khodaei, Optimal Transmission Switching in Power System Operation and Planning, Illinois Institute of Technology, December 2010

Abstract: Transmission networks are traditionally considered as fixed assets where market-based changes in transmission states are not considered by power system operators. However, system operators consider changes in transmission states by adjusting the network topology for security purposes. The adjustment in transmission state, known as transmission switching (TS), could mitigate transmission flow violations, manage congestion, enhance power system security and adjust bus voltage levels. TS, as a market tool, could potentially affect power generation dispatch and commitment and improve power system economics.

This dissertation presents the formulations and the methodologies for combining the security as well as the economic features of TS. The TS applications are incorporated into the DC model of security-constrained unit commitment (SCUC) for the day-ahead power system scheduling. The dissertation will also consider the AC solution of SCUC for TS applications. The TS application to the AC network solution will enhance the reactive power flow for mitigating any bus voltage violations. The power system operation results are compared based on the AC and the DC power network solutions and the results are discussed. TS applications are also considered in the security-constrained power system planning in which various network planning options are considered for improving the short-term TS solutions. The TS solutions will improve the real power flow and provide security and the economic feedbacks to the planning module on how the long-term planning alternatives can be improved. The results are discussed and additional recommendations are made for future TS studies in power systems.

- 7) Shaghayegh Bahramirad, Design and Implementation of Hydrokinetic Run-of-River Turbines, Illinois Institute of Technology, December 2010

The restructured electric power system considers load as a constant value and that the forecasted load value should be satisfied under any circumstances. Therefore, the competition was among generators that submit strategic bids to the ISO (independent system operator) to supply the forecasted load. The market clearing price is set by the marginal price of the last accepted generator to satisfy the fixed load.

Thus the demand-side has no role in the market clearing and price setting process. Furthermore, price spikes might occur when the demand-side has no role in setting electricity prices, so generators have no incentive to bid close to their marginal cost which would lead to bids that are much higher than actual generation costs. This behavior would lead to volatile market prices that are far from the perfectly competitive prices. The demand-side participation may reduce the system load during peak periods, which is a more economical way to respond to generation capacity shortages. Using demand-side also mitigates the potential to exercise market power, which is caused by price manipulations of generation companies. The price manipulations mainly occur when the generation schedule is obtained through the minimization of total operating cost, i.e. no load-side participation is considered. An increase in demand-side participation would have benefits for individual consumers and the entire electricity market. Demand-side participation would include distributed generation, on-site storage, and demand response. This dissertation discusses two aspects of demand side participation; distributed generation and demand response. Hydrokinetic energy as an example of distributed generation has been studied. A hydrokinetic turbine has been designed and a sensitivity analysis has been performed with an optimal placement of turbines in a hydrokinetic farm. In addition, demand response in a day ahead market clearing process has been investigated.

- 8) Cong Liu, Interdependency of Gas and Electricity in Restructured Power Systems, Illinois Institute of Technology, July 2010

Abstract: The electric power generation relies increasingly on the natural gas supply system as additional natural gas-fired power plants are installed in restructured power systems. In this context, the economics and the reliability of electric power and natural gas systems will impact one another. This dissertation addresses the interdependency of electricity and natural gas systems and proposes an integrated approach for the operation and the scheduling of the coupled energy systems.

The dissertation considers combined-cycle gas turbine units (CCGTs) as key elements for linking electric power and natural gas systems and proposes mode and component models for representing CCGTs. The component and mode models are used in scheduling of CCGTs by mixed-integer programming (MIP).

The dissertation proposes two integrated short-term scheduling models. The first one is from the viewpoint of the ISO (Independent System Operator) which proposes a security-based methodology for the unit commitment solution when considering the natural gas transmission system and contracts. The proposed solution applies a Benders decomposition method to incorporate the natural gas transmission feasibility check subproblem in the security-constrained unit commitment (SCUC) solution. The second integrated model considers a joint-operator for the coordinated scheduling of the interdependent electric power and natural gas systems. The integrated operator utilizes an augmented Lagrangian relaxation (LR) based model for the coordinated least-cost allocation of natural gas resources to individual gas loads and generating power plants.

The natural gas flow exhibits remarkable differences with the electric power flow because of the slow response of the former system and storage nature of pipelines. The dissertation also proposes an

integrated short-term scheduling model with the transient state natural gas flow formulations which is represented by a group of partial differential equations and nonlinear algebraic equations. In this dissertation, the implicit finite difference method is adopted to approximate partial differential equations into algebraic difference equations.

- 9) Saeed Kamalini, Security Constrained Expansion Planning of Fast-Response Units for Wind Integration, Illinois Institute of Technology, July 2010

Abstract: The increasing socio-environmental concerns have persuaded decision makers to support large integrations of WG (Wind Generation) in power systems. Renewable generation is fuel-free and clean which would reduce the cost of electricity production and delivery. On the other hand, WG is volatile and intermittent. WG uncertainties could decrease the expected payoff of a GENCO (Generation Company) and possibly reduce the investors' interest in the WG capacity planning. Chapters 2 and 3 in this study have developed sophisticated mechanisms for proper WG expansions. Chapter 4 discusses that proper long-term and mid-term operations planning which would include the simulation of power system uncertainties could provide a wider range of global options for managing the reliability and economics in power systems operations. From a power system's viewpoint, WG fluctuations could lead to additional system reserve requirements and the adoption of fast-response units for reliability purposes which would result in higher operation costs. Indeed, such conflicts between reliability and economics are inevitable in competitive environments. The optimal capacity expansion of renewable generation and fast-response capacity is the main theme of this dissertation. Chapter 5 discusses that the large integration of WG would also affect other generation resources including fossil fuel based and hydro units. A proper long-term or mid-term operation planning study is required to investigate the coordination of various generation resources.

This dissertation offers algorithms for managing tradeoffs between profitability and reliability. The dissertation discusses assumptions, functions, and methodologies for the large integration of WG that would maximize profits of self-interested GENCOs and enhance the power system operation reliability at the presence of uncertainties.

- 10) Yanan Cui, Investigation Into Use of Gearless Pmsg-Based Wind Farm for Grid Support, Illinois Institute of Technology, Master Thesis, December 2011

Abstract: Wind energy has become the world's fastest growing energy source, as environmental concerns have focused attention on the generation of electricity from clean and renewable sources. New capacity from wind turbines has been growing fast since 2004. Installed capacity reached 196630 Megawatt in 2010 worldwide. 2011 will also see good growth. Reliability and quality of the electrical power supply is of great importance for all grids. A well designed wind-turbine power source can help balancing the unpredictable power changes caused by the Load-side of the grid (Due to the meteorological nature of long-lasting wind at the sea, the offshore wind turbines are more stable in their power production aspect). Along more and more R&D efforts, PMSG-based direct drive wind turbine generator has become a trend in the industry, its full scale back-to-back converters can achieve

fast response of power factor tuning, which directly offers an option of generating a certain amount of reactive supporting power in solving short-term voltage stability problem in the local grid and a desired quantity of active power for mitigating the frequency oscillation in the system. Topics in this thesis includes: (1) analysis of the wind turbine generator model equipped with full scale back-to-back converters and their control schemes are proposed; (2) the low voltage ride-through test of a wind farm with the modeled wind turbine generator integrated into a finite 3-bus system is provided for further short term voltage stability studies; (3) the comparison is rendered between an offshore wind farm with no support on reactive power and the one with automatically reactive power support on voltage drop response in an 8-bus system connected with HVAC submarine cable; (4) study on dynamic active power compensation from wind farm for improving the frequency stability when large disturbance introduced..

11) Fan He, Investigation of Possible Dynamic Interaction of DFIGs of Different Capacity Existing in the Same Wind Farm, Illinois Institute of Technology, Master Thesis, December 2011

Abstract: This thesis explores the possibility of dynamic interaction between DFIGs of different capacity in a grid connected and islanding mode wind farm. The modeling of DFIG is presented in the paper. The case of adding 5 MW DFIGs to a wind farm with existing 1.5 MW DFIGs is considered. Grid-connected scenario is considered regarding the connection of the units. Moreover, step-up wind speed, noisy wind speed and fault at infinite bus will be introduced as disturbances to examine the possible dynamic interaction. Simulation using MATLAB and Simulink has been used to investigate all cases. To further justify the simulation results, a series of modal small perturbation analysis is also conducted.

12) Joan Camprubi, Sustainable Stadium: Qatar 2022, Illinois Institute of Technology, July 2011

Abstract: This thesis tries to evaluate in general terms which are the energy needs and concerns for a sustainable soccer field planned to be built for the next 2022 Qatar World Cup. To face the issue about the high temperatures and to reduce the electricity waste and greenhouse effect, several renewable energies such as solar, wind, heat pumps or piezoelectric energies would be taken into account. Some economic concerns and other approximations have been done in order to achieve a general overview of the impact of solar and wind energy to feed the stadiums grid and also make some profits at the same time that geothermal heat pumps can help to decrease air conditioning costs and piezoelectric energy can be tested and included as a future prospective to look after. Moreover is an opportunity to show to the entire world that a sustainable stadium with 8.6MW of solar and 1.6MW of wind power is feasible and Qatar could decrease their oil dependence.

13) Erik Ela, "Advanced Interaction between Day-Ahead Markets and Unit Commitment Methods with High Wind Power Penetrations," ECE Department, Illinois Institute of Technology, May 2010.

Abstract: Recent trends in the power and electrical energy industry have seen tremendous growth in the amount of installed wind power plants for use in power generation. Concerns of climate change and the availability of fossil fuels have stimulated interest in providing increasing amounts of renewable energy. Many countries see wind power as a major contributor to the total renewable energy mix. Wind power

plants have a collection of wind turbine generators that convert the power of the wind into electrical energy. The plants can cover vast areas and can have wind speeds that are variable both geographically and temporally. This variability in wind speed that leads to variability in wind power production makes wind power generation a unique source of power generation.

The power system is very complex in nature. When restructuring of the industry began, innovative ways of administering a market had to be thought of so that the laws of economics do not clash with the laws of physics. When the first energy markets were being designed, wind power held a very small fraction of the participants in the market and its unique characteristics were not anticipated. Since wind power has grown in recent years, wind power forecasting has become an essential tool to assist in its integration. This research attempts to step back to see if the current process of integrating wind power and wind power forecasts into the unit commitment and day-ahead markets is efficient. It then evaluates novel ideas from prior research to improve this process and how these new methods could be integrated into the current market structures.

4.4 List of Papers

- 1) Wei Tian, Mohammad Shahidehpour, Zuyi Li, Analysis of 2030 Large-Scale Wind Energy Integration in the Eastern Interconnection Using WINS, The Electricity Journal, Volume 24, Issue 8, October 2011, Pages 71-87

Abstract: A simulation of the 2030 load forecast in the Eastern Interconnection suggests that large-scale wind energy integration will have a major impact on the hourly commitment and dispatch of gas and coal units, especially at off-peak load hours. While fuel price alterations will have major impacts on the system production cost, load variation will have a larger impact and potential carbon costs will have the greatest impact.

- 2) S. Kamalinia, M. Shahidehpour, and A. Khodaei, "Security-constrained expansion planning of fast-response units for wind integration," Electric Power Systems Research, vol.81, no.1, pp.107-116, January 2011

Abstract: This paper proposes a stochastic expansion planning of fast-response thermal units for the large-scale integration of wind generation (WG). The paper assumes that the wind integration level is given and considers the short-term thermal constraints and the volatility of wind units in the planning of fast-response thermal units. Random outages of generating units and transmission lines as well as hourly load and wind speed forecast errors are modeled in Monte Carlo scenarios. The Monte Carlo simplification methods are introduced to handle large-scale stochastic expansion planning as a tradeoff between the solution accuracy and the calculation time. The proposed security-constrained approach can be used by an ISO or a regulatory body to secure the optimal planning of power systems while the WG integration is increasing. The effectiveness of the proposed approach is demonstrated through numerical simulations.

- 3) S. Kamalinia and M. Shahidehpour, "Generation expansion planning in wind-thermal power systems," IET Generation, Transmission & Distribution, vol.4, no.8, pp.940-951, August 2010

Abstract: The intermittency and volatility of wind generation (WG) would require additional upward and downward reserves, as well as enhanced ramping capabilities in power systems. This paper investigates the optimal expansion planning of fast-response generating capacity (e.g., gas-fired units) to accommodate the uncertainty of WG. The study utilizes a MIP-based security-constrained unit commitment (SCUC) for analyzing operational and reliability issues related to the proposed optimization problem. Numerical experiments signify the effectiveness of the proposed method.

- 4) M. Khodayar, M. Barati, and M. Shahidehpour, "Integration of High Reliability Distribution System in Microgrid Operation," IEEE Transactions on Smart Grid, Vol. 3, 2012

Abstract: In this paper, the application of high reliability distribution system (HRDS) in the economic operation of a microgrid is studied. HRDS, which offers higher operation reliability and fewer outages in microgrids, is applied to looped networks in distribution systems. The microgrid model in this study is composed of distributed energy resources (DER) including distributed generation (DG), controllable loads, and storage. The microgrid would utilize the local DER as well as the main grid for supplying its hourly load economically which is subject to power quality and reliability requirements. The HRDS implemented at Illinois Institute of Technology (IIT) is used as a case study along with the local DER to increase the load point reliability and decrease the operation cost of the IIT microgrid. The availability of distribution lines, main grid supply, and microgrid generation is considered using the Markov chain Monte Carlo simulation in the microgrid scenarios. The reliability indices based on frequency and duration of outages are measured at the microgrid level and the load point level, and the potential system enhancements are discussed for improving the economic operation of the IIT microgrid.

- 5) A. Khodaei, M. Shahidehpour, "Microgrid-based Co-optimization of Generation and Transmission Planning in Power Systems," IEEE Transactions on Power Systems, Vol. 27, 2012

Abstract: This paper presents an algorithm for the microgrid planning as an alternative to the co-optimization of generation and transmission expansion planning in electric power systems. The integration of microgrids in distribution systems will offer a decentralized control of local resources for satisfying the network reliability and the power quality required by local loads. The objective in this paper is to minimize the total system planning cost comprising investment and operation costs of local microgrids, the co-optimized planning of large generating units and transmission lines, and the expected cost of unserved energy. The cost of unserved energy reflects the cost of load shedding which is added to the objective function for reliability considerations. The microgrid-based co-optimization planning problem is decomposed into a planning problem and annual reliability subproblem. The optimal integer planning decisions calculated in the planning problem will be examined against the system reliability limits in the subproblem and the planning decisions will be revised using proper feasibility cuts if the annual reliability limits are violated. Numerical simulations demonstrate the effectiveness of the

proposed microgrid-based co-optimization planning in power systems and explore the economic and reliability merits of microgrid planning as compared to grid-based generation and transmission upgrades.

- 6) M. Khodayar and M. Shahidehpour, "Stochastic Price-based Coordination of Intra-hour Wind Energy and Storage in a Generation Company," IEEE Transactions on Sustainable Energy, 2012

Abstract: This paper develops a day-ahead price-based scheduling strategy for the coordination of wind and storage units in a generating company (GENCO). The proposed strategy is based on the stochastic price-based unit commitment (PBUC) which considers volatilities in day-ahead intra-hour market prices and wind power generation when scheduling wind and storage units. The proposed approach firms up the hourly sum of wind and storage unit generation, and mitigate potential wind energy imbalance charges for GENCOs in electricity markets. Although the proposed approach applies to any kind of storage, we consider the pumped-storage hydro (PS) unit in this study. Numerical examples illustrate a GENCO's day-ahead coordinated scheduling results for wind and PS units.

- 7) H. Wu, M. Shahidehpour, and A. Al-Abdulwahab, "Hourly Demand Response in Day-ahead Scheduling for Managing the Variability of Renewable Energy," IET Journal on Generation, Transmission & Distribution, 2012

Abstract: This paper proposes a stochastic optimization model for the day-ahead scheduling in power systems, which incorporates the hourly demand response (DR) for managing the variability of renewable energy sources (RES). DR considers physical and operating constraints of the hourly demand for economic and reliability responses. The proposed stochastic day-ahead scheduling algorithm considers random outages of system components and forecast errors for hourly loads and RES. The Monte Carlo simulation (MCS) is applied to create stochastic security-constrained unit commitment (SCUC) scenarios for the day-ahead scheduling. A general purpose MILP software is employed to solve the stochastic SCUC problem. Numerical results in the paper demonstrate the benefits of applying DR to the proposed day-ahead scheduling with variable renewable energy sources.

- 8) A. Khodaei, M. Shahidehpour, L. Wu, and Z. Li, "Coordination of Short-Term Operation Constraints in Multi-Area Expansion Planning," IEEE Transactions on Power Systems, Vol. 27, 2012

Abstract: This paper presents a comprehensive expansion planning algorithm of generation and transmission components in multi-area power systems. The objective is to minimize the total system cost in the planning horizon, comprising investment and operation costs and salvage values subject to long-term system reliability and short-term operation constraints. The multi-area expansion planning problem is decomposed into a planning problem and annual reliability subproblems. The planning decisions calculated in the planning problem would also satisfy the short-term operation constraints. A detailed model of thermal and hydro units is considered using the mixed-integer programming (MIP) formulation. In addition, a multi-state representation for the expansion planning of renewable energy units is explored. The proposed approach considers customers' demand response as an option for reducing the short-term operation costs. The planning problem solution is applied to the annual

reliability indices subproblems which examine system reliability indices as a post-processor. If the reliability limit is not satisfied, additional reliability constraints will be introduced which are based on the sensitivity of system reliability index to investment decisions. The new reliability constraints are added to the next iterations of the planning problem to govern the revised plan for the optimal expansion. Numerical simulations indicate the effectiveness of the proposed approach for solving the operation-constrained multi-area expansion planning problem of practical power systems.

- 9) C. Sahin, M. Shahidehpour, I. Erkmén, "Allocation of Hourly Reserve versus Demand Response for Security-Constrained Scheduling of Stochastic Wind Energy," IEEE Transactions on Sustainable Energy, 2012

Abstract: This paper presents a stochastic method for the hourly scheduling of optimal reserves when the hourly forecast errors of wind energy and load are considered. The approach utilizes the stochastic security-constrained unit commitment (SCUC) model and a two-stage stochastic programming for the day-ahead scheduling of wind energy and conventional units with N-1 contingencies. The effect of aggregated hourly demand (DR) response is considered as a means of mitigating transmission violations when uncertainties are considered. The proposed mixed-integer programming (MIP) model applies the Monte Carlo method for representing the hourly wind energy and system load forecast errors. A 6-bus, 118-bus, and the Northwest region of Turkish electric power network are considered to demonstrate the effectiveness of the proposed day-ahead stochastic scheduling method in power systems.

- 10) M. Khodayar, L. Wu, and M. Shahidehpour, "Hourly Coordination of Electric Vehicle Operation and Volatile Wind Power Generation in SCUC," IEEE Transactions on Smart Grid, Vol. 3, No. 3, pp. 1271-1279, Sept. 2012

Abstract: In this paper, the coordinated integration of aggregated plug-in electric vehicle (PEV) fleets and renewable energy sources (wind energy) in power systems is studied by stochastic security-constrained unit commitment (Stochastic SCUC) model, which minimizes the expected grid operation cost while considering the random behavior of the many PEVs. PEVs are mobile and distributed devices with deferrable options for the supply/utilization of energy at various times and locations. The increased utilization of PEVs, which consume electricity rather than fossil fuel for driving, offers unique economic and environmental opportunities, and brings out new challenges to electric power system operation and planning. The storage capability of PEVs could help power systems mitigate the variability of renewable energy sources and reduce grid operation costs. Vehicle-to-grid (V2G) enables PEVs to have bi-directional power flows once they are connected to the grid, i.e., they can either inject power to, and draw power from, the grid which adds further complexity to power system operations. PEVs signify customers' random behavior when considering their driving patterns, locational energy requirements, topological grid interconnections, and other constraints imposed by the consumers. Numerical tests demonstrate the effectiveness of the proposed approach for analyzing the impact of PEVs on the grid operation cost and hourly wind energy dispatch.

- 11) A. Lotfjou, Y. Fu, and M. Shahidehpour, "Hybrid AC/DC Transmission Expansion Planning," IEEE Transactions on Power Delivery, Vol. 27, No. 3, pp. 1620-1628, July 2012

Abstract: This paper proposes a hybrid algorithm for the AC/DC transmission expansion planning (TEP). The stochastic simulation method would consider random outages of generating units and AC/DC transmission lines as well as load forecast errors. The mixed-integer linear programming problem is decomposed into a master planning problem with integer investment decision variables and subproblems which examine the feasibility of master planning solution and calculate the optimal operation schedule over the planning horizon. The independent system operator (ISO) would utilize the proposed method to select the optimal set of AC/DC transmission lines for satisfying TEP criteria: supplying load forecasts, minimizing investment costs, and optimizing market operations. The proposed set of DC transmission system may use either current source converters (CSCs) or voltages source converters (VSCs). Numerical examples illustrate the effectiveness of the proposed TEP model.

- 12) L. Abreu, M. Khodayar, M. Shahidehpour, L. Wu, "Risk-Constrained Coordination of Cascaded Hydro Units with Volatile Wind Power Generation" IEEE Transactions on Sustainable Energy, Vol. 3, No. 3, pp. 359-368, July 2012

Abstract: This paper presents a stochastic hourly coordination strategy for wind units and cascaded hydro generation as storage to firm up the hourly dispatch in a generating company (GENCO). The proposed strategy is based on the stochastic price-based unit commitment (Stochastic PBUC) formulation which includes wind energy imbalance charges. The forecast errors of electricity market price and wind speed are simulated with the Monte Carlo method via a scenario approach. The risk-aversion constraints are considered for limiting a GENCO's financial risks when considering uncertain wind power generation. The proposed optimization model is solved by mixed-integer linear programming (MIP) and illustrative examples examine the effectiveness of the proposed risk-based coordination model for optimizing a GENCO's payoff.

- 13) C. Sahin, M. Shahidehpour, and I. Erkmén, "Generation Risk Assessment in Volatile Conditions with Wind, Hydro, and Natural Gas Units" Applied Energy, Vol. 96, pp. 4-11, Aug. 2012

Abstract: This paper studies a generating company (GENCO)'s midterm (a few months to a year) scheduling payoffs and risks in volatile operating conditions. The proposed algorithm considers the integration of intermittent wind units into a GENCO's generation assets and coordinates the GENCO's hourly wind generation schedule with that of natural gas (NG) units (with volatile gas prices) and hydro units (with water inflow forecast) for maximizing the GENCO's payoff. The proposed midterm GENCO model applies market price forecasts to the risk-constrained stochastic price-based unit commitment (PBUC) for calculating the GENCO's risk in energy and ancillary services markets. The proposed PBUC minimizes the cost of a) NG contracts, storage, startup and shutdown, b) startup and shutdown of cascaded hydro units, and c) penalty for defaulting on the scheduled power delivery. Simulation results show that the diversification of generating assets including bilateral contracts (BCs) could enhance the GENCO's midterm planning by increasing the expected payoff and decreasing the financial risk.

- 14) L. Wu, M. Shahidehpour, and Z. Li, "Comparison of Scenario-Based and Interval Optimization Approaches to Stochastic SCUC," IEEE Transactions on Power Systems, Vol. 27, No. 2, pp. 913-921, May 2012

Abstract: This paper compares applications of scenario-based and interval optimization approaches to stochastic security-constrained unit commitment (Stochastic SCUC). The uncertainty of wind power generation is considered in this study to compare the two approaches, while other types of uncertainty can be addressed similarly. For the simulation of uncertainty, the scenario-based approach considers the Monte Carlo (MC) method, while lower and upper bounds are adopted in the interval optimization. The Stochastic SCUC problem is formulated as a mixed-integer linear programming (MIP) problem and solved using the two approaches. The scenario-based solutions are insensitive to the number of scenarios, but present additional computation burdens. The interval optimization solution requires less computation and automatically generates lower and upper bounds for the operation cost and generation dispatch, but its optimal solution is very sensitive to the uncertainty interval. The numerical results on a 6-bus system and the modified IEEE 118-bus system show the attributes of the two approaches for solving the Stochastic SCUC problem. Several convergence acceleration options are also discussed for overcoming the computation obstacles in the scenario-based approach.

- 15) A. Khodaei and M. Shahidehpour, "Security-Constrained Transmission Switching with Voltage Constraints," International Journal of Electrical Power and Energy Systems, Vol. 35, No. 1, pp. 74-82, Feb. 2012

Abstract: Transmission switching (TS) would play a vital role in the security and economics of electric power systems. The application of TS to the AC model of security-constrained unit commitment (SCUC) for the day-ahead scheduling is presented in this paper. The proposed AC model of SCUC with TS would include real and reactive power flow constraints which increase the controllability of base case and contingency solutions with voltage constraints. A general FACTS model is introduced for the reactive power management in SCUC which is based on the power injection model (PIM). A modified Newton-Raphson power flow model is introduced in the proposed SCUC with TS in which line flows are considered as variables. The proposed AC network model is compared with the DC network model (without voltage constraints) for enhancing the power network controllability and minimizing the operation cost. The case studies exhibit the effectiveness of the TS application to SCUC with AC network constraints.

- 16) A. Khodaei, M. Shahidehpour, and S. Bahramirad, "SCUC With Hourly Demand Response Considering Intertemporal Load Characteristics," IEEE Transactions on Smart Grid, Vol. 2, No. 3, pp. 564-571, Sept. 2011

Abstract: In this paper, the hourly demand response (DR) is incorporated into security-constrained unit commitment (SCUC) for economic and security purposes. SCUC considers fixed and responsive loads. Unlike fixed hourly loads, responsive loads are modeled with their inter-temporal characteristics. The responsive loads linked to hourly market prices can be curtailed or shifted to other operating hours. The

study results show that DR could shave the peak load, reduce the system operating cost, reduce fuel consumptions and carbon footprints, and reduce the transmission congestion by reshaping the hourly load profile. Numerical simulations in this paper exhibit the effectiveness of the proposed approach.

- 17) L. Wu and M. Shahidehpour, "Optimal Coordination of Stochastic Hydro and Natural Gas Supplies in Midterm Operation of Power Systems," IET Journal on Generation, Transmission & Distribution, Vol. 5, No. 5, pp. 577-587, May 2011

Abstract: This paper presents a stochastic security-constrained unit commitment (SCUC) model for the optimization of coordinated midterm water and natural gas supplies. The stochastic model considers random outages of system components, load forecast errors, and water inflow uncertainty, which are modeled as scenarios in the Monte Carlo (MC) simulation. Water resources may be used in winter to cover gas unit outages caused by an insufficient gas supply. However, those hydro units may not then be available for peak load shaving in the following summer if the summer happens to be a dry season. Thus, water reservoirs would have to be utilized efficiently throughout the year to provide substantial cost reductions while maintaining the power system reliability. The proposed model also considers the impact of midterm scheduling of water and gas on the power system reliability. Reliability indices are incorporated in the hourly unit commitment problem. The stochastic problem is formulated as a two-stage optimization where the first stage optimizes the short-term water and gas usages and the second stage considers the midterm schedule. Numerical simulations indicate the effectiveness of the proposed stochastic approach for the optimal scheduling of midterm water and gas usages.

- 18) C. Liu, M. Shahidehpour, J. Wang, "Coordinated Scheduling of Electricity and Natural Gas Infrastructures with a Transient Model for Natural Gas Flow," Chaos (American Institute of Physics), Vol. 21, pp. 025102-1 through 025102-12, May 2011

Abstract: This paper focuses on transient characteristics of natural gas flow in the coordinated scheduling of security-constrained electricity and natural gas infrastructures. The paper takes into account the slow transient process in the natural gas transmission systems. Considering their transient characteristics, natural gas transmission systems are modeled as a set of partial differential equations (PDEs) and algebraic equations. An implicit finite difference method is applied to approximate PDEs by difference equations. The coordinated scheduling of electricity and natural gas systems is described as a bi-level programming formulation from the independent system operator's viewpoint. The objective of the upper-level problem is to minimize the operating cost of electric power systems while the natural gas scheduling optimization problem is nested within the lower-level problem. Numerical examples are presented to verify the effectiveness of the proposed solution and to compare the solutions for steady-state and transient models of natural gas transmission systems.

- 19) C. Sahin, Z. Li, M. Shahidehpour, and I. Erkmén, "Impact of Natural Gas System on Risk-Constrained Midterm Hydrothermal Scheduling," IEEE Transactions on Power Systems, Vol. 26, No. 2, pp. 520-531, May 2011

Abstract: This paper studies the impact of natural gas (NG) contracts and constraints on a GENCO's midterm risk-constrained hydrothermal scheduling problem. The NG contracts and constraints are modeled as a set of linear equations. The proposed model utilizes the stochastic price-based unit commitment (PBUC). The PBUC hourly solution considers uncertainties of market prices for energy and ancillary services, uncertainties of natural water inflows, and random NG infrastructure interruptions in Monte-Carlo scenarios. Illustrative examples analyze the GENCO's risk levels when considering midterm schedules for generating units, target payoffs, and usages of water inflow, NG and other thermal resources. Simulation results show that a GENCO's midterm schedules and financial risks could be impacted significantly with the consideration of NG contracts and constraints.

- 20) A. Lotfjou, M. Shahidehpour, and Y. Fu, "Hourly Scheduling of DC Transmission Lines in SCUC With Voltage Source Converters," IEEE Transactions on Power Delivery, Vol. 26, No. 2, pp. 650-660, April 2011

Abstract: This paper presents the modeling of high voltage direct current (DC) transmission systems with voltage source converters (VSCs) in security-constrained unit commitment (SCUC). The impact of VSC-DC transmission system on the economics and the security of integrated AC/DC transmission systems is discussed. The nonlinear AC/DC equations are linearized and the Newton-Raphson method is utilized to solve the linearized network in the base case and contingencies. The SCUC solution will determine the optimal hourly schedule of controllable VSC-DC transmission systems in electricity markets. Numerical examples show the efficiency of the proposed model.

- 21) C. Liu, M. Shahidehpour, and J. Wang, "Application of Augmented Lagrangian Relaxation to Coordinated Scheduling of Interdependent Hydrothermal Power and Natural Gas Systems," IET Journal on Generation, Transmission & Distribution, Vol. 4, No. 12, pp. 1314–1325 Dec. 2010

Abstract: This paper proposes an optimization model for the coordinated scheduling of interdependent electric power and natural gas transmission systems from a joint operator's viewpoint. The objective is to minimize the coordinated social cost while satisfying network and temporal constraints of the two interdependent systems. The joint operator will coordinate hourly schedules to supply natural gas to loads or generate electric power. We consider the application of LR or augmented LR to relax the coupling constraints of the two systems. The Lagrangian dual is decomposed into the security-constrained unit commitment subproblem with the hydro coordination (SCUC) and the natural gas allocation subproblem. The application of LR for solving the coordinated problem could cause oscillations in the dual solution which is due to the nonconvex characteristics of the coordinated problem represented by integer variables and network constraints. Moreover, with slight changes in multiplier values, the linear cost function of the natural gas well may result in a cycling behavior of the gas well output between its max and min limits. To avoid numerical oscillations and improve the solution quality, the augmented LR with a piecewise linear approximation of quadratic penalty terms and the block descent coordination (BDC) technique are proposed. We consider the 6-bus with 7-node and the 118-bus with 14-node systems to verify that the applicability of the proposed method to the coordinated scheduling of electric power and natural gas transmission systems.

- 22) A. Khodaei and M. Shahidehpour, Y. Fu, "Transmission Switching in Security-Constrained Unit Commitment," IEEE Transactions on Power Systems, Vol. 25, No. 4, pp. 1937-1945, Nov. 2010

Abstract: Transmission switching (TS) is introduced in security-constrained unit commitment (SCUC) for alleviating transmission violations and reducing operating costs. The SCUC problem is decomposed into the unit commitment (UC) master problem and the TS subproblem. The UC master problem finds the optimal hourly schedule of generating units. The TS subproblem uses this solution for transmission switching to find the optimal dispatch of units when considering network constraints. The TS subproblem also examines contingencies and identifies required changes to the UC master problem solution when contingencies cannot be mitigated in the TS subproblem. To propose a practical TS model, the standing phase angle difference limit is considered and relevant constraints are added to the TS subproblem. The case studies exhibit the effectiveness of the proposed approach.

- 23) L. Wu and M. Shahidehpour, Y. Fu, "Security-Constrained Generation and Transmission Outage Scheduling with Uncertainties," IEEE Transactions on Power Systems, Vol. 25, No. 3, pp. 1674-1685, Aug. 2010

Abstract: This study presents a stochastic model for the Independent System Operator's (ISO's) optimal coordinated long-term maintenance scheduling of generation units and transmission lines with short-term security-constrained unit commitment (SCUC). Random disturbances of power systems including forced outages of generation units and transmission lines, load forecast errors, and fuel price fluctuations are modeled as scenario trees using the Monte Carlo simulation. Lagrangian relaxation (LR) is applied to separate the coordinated optimization problem into long-term equipment maintenance (LTEM) and stochastic long-term SCUC (LTSCUC) subproblems. For the stochastic LTSCUC subproblem, scenario bundle constraints are relaxed via LR and the optimization problem is decomposed into deterministic LTSCUC problems. LR is applied to each deterministic LTSCUC to relax long-term fuel and emission limits and decompose the problem into short-term SCUC subproblems. The decomposition is further applied to short-term SCUC subproblems for separating hourly unit commitment and transmission network constraints. The unit commitment is formulated as a mixed-integer programming (MIP) problem and solved by the branch-and-cut method using CPLEX. The outcome of this study includes the hourly scheduling of outages of generation units and transmission lines, which corresponds to the optimal generation unit commitment and dispatch, and transmission flows. The hourly schedules minimize the total cost of operation and maintenance and satisfy long-term and short-term constraints of generation units and transmission network with the inclusion of power system uncertainty. A modified IEEE-118 bus system is used to exhibit the effectiveness of the proposed scheduling approach.

- 24) A. Khodaei and M. Shahidehpour, S. Kamalinia, "Transmission Switching in Expansion Planning," IEEE Transactions on Power Systems, Vol. 25, No. 3, pp. 1722-1733, Aug. 2010

Abstract: Transmission switching (TS) is introduced to add flexibility to the transmission and generation capacity expansion planning problem. TS could improve the performance of the capacity expansion planning model and reduce the total planning cost. The capacity expansion planning problem is

decomposed into a master problem and two subproblems. The master problem utilizes the candidate set for additional generating unit and transmission capacity investments to find the optimal plan throughout the planning horizon. The subproblems use the optimal plan, apply transmission switching to relieve any transmission flow violations, and calculate the optimal dispatch of generating units. The transmission network contingencies are also considered in the subproblems. The case studies exhibit the effectiveness of the proposed expansion planning approach.

- 25) O. Tor, A. Guven, and M. Shahidehpour, "Promoting the Investment on IPPs for Optimal Grid Planning," IEEE Transactions on Power Systems, Vol. 25, No. 3, pp. 1743-1750, Aug. 2010

Abstract: This paper presents a transmission expansion planning (TEP) model which coordinates investment decisions in monopolistic transmission and decentralized generator sectors. The proposed planning approach gauges transmission congestion and security constraints with respect to transmission investments while promoting investments on independent power produces (IPPs) through incentive payments. The paper includes discussions on incentive mechanisms and prioritization among qualified IPPs for several planning scenarios. Such incentives might be necessary to trigger investments on IPPs earlier than those projected by the decentralized generation system, when the power system security is threatened. The proposed planning approach would optimize the sum of transmission investments, incentive payments to IPPs, and congestion costs along the planning horizon. The case studies illustrate how the proposed planning algorithm could be utilized in order to determine incentive payments to candidate generators when necessary, and prioritize such incentives among multiple IPP candidates.

- 26) L. Wu and M. Shahidehpour, "A Hybrid Model for Price Forecasting," IEEE Transactions on Power Systems, Vol. 25, No. 3, pp. 1519-1530, Aug. 2010

Abstract: This paper presents a hybrid time-series and adaptive wavelet neural network (AWNN) model for the day-ahead electricity market clearing price forecast. Instead of using price series, one-period continuously compounded return series is used to achieve more attractive statistical properties. The autoregressive moving average with exogenous variables (ARMAX) model is used to catch the linear relationship between price return series and explanatory variable load series, the generalized autoregressive conditional heteroscedastic (GARCH) model is used to unveil the heteroscedastic character of residuals, and AWNN is used to present the non-linear, non-stationary impact of load series on electricity prices. The Monte Carlo method is adopted to generate more evenly distributed random numbers used for time series and AWNN models to accelerate the convergence. Several criteria such as average mean absolute percentage error (AMAPE) and the variance of forecast errors are used to assess the model and measure the forecasting accuracy. Illustrative price forecasting examples of the PJM market are presented to show the efficiency of the proposed method.

- 27) L. Wu and M. Shahidehpour, Y. Fu, "Accelerating the Benders Decomposition for Network-Constrained Unit Commitment Problems," Energy Systems, Vol. 1, pp. 339-376, July 2010

Abstract: This study presents an optimization method by generating multiple strong Benders cuts for accelerating the convergence of Benders Decomposition (BD) when solving the network-constrained

generation unit commitment (NCUC) problem. In NCUC, dc transmission network evaluation subproblems are highly degenerate, which would lead to many dual optimal solutions. Furthermore, the classical BD cuts are often low-density which involve only a limited number of decision variables in the master problem. Therefore, the dual optimal solutions and the corresponding Benders cuts are of crucial importance for improving the efficiency of the BD algorithm. The proposed method would generate multiple strong Benders cuts, which are pareto optimal, among candidates from multiple dual optimal solutions. Such cuts would be high-density in comparison with low-density cuts produced by the classical BD. The proposed multiple strong Benders cuts are efficient in terms of reducing the total iteration number and the overall computing time. The high-density cuts may restrict the feasible region of the master unit commitment (UC) problem in each iteration as they incorporate more decision variables in each Benders cut. The multiple strong Benders cuts would accordingly reduce the iteration number and overall computing time. Numerical tests demonstrate the efficiency of the proposed multiple strong Benders cuts method in comparison with the classical BD algorithm and the linear sensitivity factors (LSF) method. The proposed method can be extended to other applications of BD for solving the large-scale optimization problems in power systems operation, maintenance, and planning.

28) C. Liu, M. Shahidehpour, and L. Wu, "Extended Benders Decomposition for Two-Stage SCUC, IEEE Transactions on Power Systems, Vol. 25, No. 2, pp. 1192-1194, May 2010

Abstract: This paper presents the solution of a two-stage security-constrained unit commitment (SCUC) problem. The proposed SCUC model could include integer variables at the second stage. A framework of extended Benders decomposition with linear feasibility and optimality cuts is proposed for the solution of mixed-integer programming (MIP) problems at both stages. Test results show the effectiveness of the proposed methodology.

29) S. Kamalinia and M. Shahidehpour, "Capacity Adequacy Calculation by Considering Locational Capacity Prices," IET Journal on Generation, Transmission & Distribution, Vol. 4, No. 3, pp. 376-385, Feb. 2010

Abstract: A proper investment mechanism is required in restructured power systems to secure the adequacy of installed capacity by encouraging investments on generation and transmission expansions. In this paper, we propose a locational capacity price (LCP) model along with multi-level load bidding curves, which reflect the effectiveness of the market-based capacity payment and at the same time, prohibits the capacity withholding and the exercising of market power. The purpose of capacity expansion decision is analyzed and compared with three other market design options, i.e., energy only, capacity payment, and installed capacity. The case studies show that the proposed LCP method provides proper investment signals in capacity-constrained locations. The proposed LCP method also provides signals to system operators to alleviate transmission congestions economically using proper operation strategies in power systems.

- 30) A. Lotfjou and M. Shahidehpour, "Security-Constrained Unit Commitment with AC/DC Transmission Systems," IEEE Transactions on Power Systems, Vol. 25, No. 1, pp. 531-543, Feb. 2010

Abstract: This paper presents the solution of security- constrained unit commitment (SCUC) problem with a detailed representation of high voltage direct current (DC) transmission system with current source converter (CSC). We find an economic operation and control strategy for AC and CSC-DC transmission systems by solving the SCUC problem with AC/DC transmission constrains. The presented model is decomposed into a master problem for the solution of hourly unit commitment (UC) problem and subproblems that examine the security (branch flows and bus voltages) of integrated AC/DC transmission systems. The solution of transmission security check subproblem is based on linear programming (LP) which minimizes AC bus mismatches subjected to AC/DC transmission security constraints. The iterative SCUC solution coordinates the power transfer on the DC transmission system for enhancing the economics and the security of AC transmission system. The numerical tests illustrated the efficiency of the proposed model.

- 31) Wei Tian, Zuyi Li, Mohammad Shahidehpour, "Transmission Congestion Analysis in the Eastern Interconnection using POMS," IEEE Power and Energy Society General Meeting, July 2010, Minneapolis, Minnesota.

Abstract: A methodology based on the security-constrained unit commitment (SCUC) is applied to analyze the transmission congestion in the Eastern Interconnection of the United States for 2008 and 2018. The proposed SCUC tool for this study is referred to as the POver Market Simulator (POMS). The identified congestions are visualized along with the Geographical Information System (GIS) data and compared with the results published by the U.S. Department of Energy's National Electric Transmission Congestion Study (NETCS) in 2006. The POMS study also provides the locational marginal price (LMP) information in the Eastern Interconnection, which is not available in the NETCS report. The POMS simulation results for representing congested branches and LMPs could be applied to the future transmission expansion planning studies.

- 32) Yinan Cui, Hasan Shanechi, Zuyi Li, IEEE, Mohammad Shahidehpour, Investigation into Use of PMSG-based Wind Farm for Grid Support, Submitted to IEEE Energy Tech 2012 Conference.

Abstract: Reliability and quality of the electrical power supply is of great importance for all grids. A well designed wind farm can help balancing the unpredictable power changes caused by the load-side of the grid. This paper offers some simulation tests on using PMSG-based direct drive wind turbine generator with full scale back-to-back converters for grid support. Different cases have been presented to show that wind energy could be an efficient back-up plan for voltage regulation and a brief study has been carried out which concentrates on possible dynamic compensation on improving the frequency stability of the grid.

- 33) Fan He, Hasan Shanechi, Zuyi Li, IEEE, Mohammad Shahidehpour, Investigation of Possible Dynamic Interaction between DFIGs of Different Capacity Operating in the Same Wind Farm, Submitted to IEEE Energy Tech 2012 Conference.

Abstract: This paper explores the possibility of dynamic interaction between DFIGs of different capacity in a grid connected and islanding mode wind farm. The modeling of DFIG is presented in the paper. The case of adding 5 MW DFIGs to a wind farm with existing 1.5 MW DFIGs is considered. Grid connected scenario is considered regarding the connection of the units. Moreover, step-up wind speed and fault at infinite bus will be introduced as disturbances to examine the possible dynamic interaction. Simulation using MATLAB and Simulink has been used to investigate all cases. To further justify the simulation results, a series of modal small perturbation analysis is also conducted.

4.5 List of Courses

- 1) Graduate Course: ECE 580 – Elements of Sustainable Energy, Illinois Institute of Technology, Fall 2010

This course covers cross-disciplinary subjects on sustainable energy that relate to energy generation, transmission, distribution, and delivery as well as theories, technologies, design, policies, and integration of sustainable energy. Topics include wind energy, solar energy, biomass, hydro, nuclear energy, and ocean energy. Focus will be on the integration of sustainable energy into the electric power grid, the impact of sustainable energy on electricity market operation, and the environmental impact of sustainable energy.

- 2) Graduate Course: ECE 581 – Elements of Smart Grid, Illinois Institute of Technology, Fall 2010

This course covers cross-disciplinary subjects on smart grid that relates to energy generation, transmission, distribution, and delivery as well as theories, technologies, design, policies, and implementation of smart grid. Topics include: smart sensing, communication, and control in energy systems; advanced metering infrastructure; energy management in buildings and home automation; smart grid applications to plug-in vehicles and low-carbon transportation alternatives; cyber and physical security systems; microgrids and distributed energy resources; demand response and real-time pricing; and intelligent and outage management systems.

- 3) Professional Course: Wind Energy Technology, Interconnection & Integration, EnerNex

This course is intended to provide the necessary background for engineers and researchers by addressing various aspects of interconnecting wind power plants into electric power systems. The study course is designed to provide knowledge on the state-of-the-art of wind-technology and wind-integration related issues. The study course will mainly discuss insights on dealing with high wind power penetration levels in North America networks. In addition, a brief summary on the European wind

energy performance is also presented. This course is targeted towards power systems engineering and management personnel from utilities, RTOs, ISOs, and ITCs as well as consultants, manufacturers and developers involved with the evaluation and planning of the interconnection and operation of new wind plants. The students and professors who are working in the field of wind energy and technology will also benefit from this study course. This course is divided in 11 sessions which will be covered in 3 days. The sessions will begin at 10.00 AM each day. The duration of each session will be 45 minutes. At the end of each day attendees will be given an opportunity to raise any topics for discussion.

5. Conclusions

Researches in this project on wind integration included (1) Development of WINS; (2) Transmission Congestion Analysis in the Eastern Interconnection; (3) Analysis of 2030 Large-Scale Wind Energy Integration in the Eastern Interconnection; (4) Large-scale Analysis of 2018 Wind Energy Integration in the Eastern U.S. Interconnection. Specifically,

- WINS simulates the actual market operations which is based on the security-constrained unit commitment (SCUC) with full AC transmission and voltage constraints considered. The computational engine of WINS is written in Microsoft Visual C++, and the web-based Graphical User Interface (GUI) is written in Microsoft Visual C# and ASP.NET. The database is based on ORACLE and can be extended to include other database formats as well. Microsoft Excel is used for the downloading reports. The input WINS data include (1) generation data (unit type, capacity, availability; cost information; unit operating constraints such as max/min capacities, ramping up/down rates, min on/off times, maximum number of start-ups); (2) wind data (8760 hourly profile); (3) transmission data (network topology, line parameters, control transformers, normal/contingency limits for line flows and bus voltages); and (4) load data (hourly load and distribution, demand bids and load shedding cost and data).
- A methodology based on the security-constrained unit commitment (SCUC) is applied to analyze the transmission congestion in the Eastern Interconnection of the United States for 2008 and 2018. The proposed SCUC tool for this study is referred to as the POver Market Simulator (POMS). The identified congestions are visualized along with the Geographical Information System (GIS) data and compared with the results published by the U.S. Department of Energy's National Electric Transmission Congestion Study (NETCS) in 2006. The POMS study also provides the locational marginal price (LMP) information in the Eastern Interconnection, which is not available in the NETCS report. The POMS simulation results for representing congested branches and LMPs could be applied to the future transmission expansion planning studies.
- A comprehensive large-scale wind energy integration analysis is considered which is based on the 2030 load forecast in the Eastern Interconnection of the United States. This study is performed using WINS. In this study, transmission constraints are not considered when studying the wind energy portfolios. The wind energy integration is studied based on the capacity factors of potential wind sites. Wind energy contributions to peak/off-peak annual production costs are studied based on the WINS simulation results. The sensitivity of fuel costs, wind energy production, hourly loads, carbon costs, and load management are analyzed in the wind energy integration Scenarios. The results of the study suggest that large-scale wind energy integration will have a major impact on the hourly commitment and dispatch of gas and coal units, especially at off-peak load hours. While fuel price alterations will have major impacts on the system production cost, load variation will have a larger impact and potential carbon costs will have the greatest impact.
- A comprehensive large-scale wind energy integration analysis is implemented based on the 2018 load forecast in the Eastern Interconnection of the United States. This study is performed using WINS. The wind energy integration with/without transmission constraints are studied and

analyzed. The sensitivity of fuel price, wind energy production, load, carbon cost, and load shedding are implemented to study the impact of volatility of major parameters on the WINS simulation results. 19 Scenarios are studied and analyzed. The main observations based on the simulations are listed as follows: (1) Production cost is more sensitive to transmission constraints than to wind energy integration; (2) The location of wind energy integration could have an impact on the wind energy dispatch in the hourly generation portfolio; (3) The addition of wind generation units at certain locations in the Eastern Interconnection may cause additional transmission congestion; (4) In 2018, the replacement of coal units by wind energy at certain locations could mitigate transmission congestion; (5) Wind energy is often available and can replace fossil energy at off-peak load hours. During certain seasons when wind is unavailable, wind energy supply could be replaced by fossil energy; (6) In 2018, wind energy is transmitted mostly at 500kV, 345kV, and 230kV transmission levels while the 765kV transmission is utilized less by wind generation units; (7) Higher costs for gas and oil will result in additional transmission congestion as power systems try to use cheaper coal units located centrally in fewer geographical spots. Such limited utilizations of centrally located resources may also limit the available dispatch of wind generating units; (8) Higher levels of wind energy integration could result in higher levelized congestion costs when wind generation units, located at few geographical spots, try to supply a significant level of load; (9) Carbon cost demonstrates the highest impact on the 2018 simulation results. Higher carbon costs will be instrumental in mitigating the regional transmission congestion in the Eastern Interconnection; (10) Load forecast uncertainty will have a larger impact on the 2018 simulation results as compared to fluctuations in fuel prices or possible levels of wind energy integration; (11) The levelized congestion cost may not increase monotonically with higher levels of bus loads; (12) Peak load shaving will have a major impact on the commitment and dispatch of gas units because peak loads are mostly supplied by such units. The WINS simulation results shows that lowering the hourly volatility of load profile by introducing smart grid, additional distribution automation for the utilization of demand response, and the large-scale integration of wind energy and storage could lower the transmission congestion and improve the economics and the optimal operation of power systems in the Eastern Interconnection of the United States.

The education activities in this project on wind energy included (1) Wind Energy Training Facility Development; (2) Wind Energy Course Development. Specifically,

- To fulfill the mission on workforce training and education, the Consortium erected a permanent facility at IIT for Workforce Training and Education on Sustainable Energy and Smart Grid. IIT secured funds from the State of Illinois to renovate the 16,000 sqft of space for establishing the facility. This project provided funds to furnish the facility with the state-of-the-art equipment to offer a world-class training and education on sustainable energy at IIT. The facility has provided and will continue to provide training on sustainable energy to various sectors including power industry employees, union workers, high school teachers, the public, and students through instructor-led and internet-based training courses.

- Graduate Courses in Wind Energy were developed and offered at IIT. The course “Elements of Sustainable Energy” covers cross-disciplinary subjects on sustainable energy that relate to energy generation, transmission, distribution, and delivery as well as theories, technologies, design, policies, and integration of sustainable energy. Topics include wind energy, solar energy, biomass, hydro, nuclear energy, and ocean energy. Focus was on the integration of sustainable energy into the electric power grid, the impact of sustainable energy on electricity market operation, and the environmental impact of sustainable energy. The course “Elements of Smart Grid” at IIT covers cross-disciplinary subjects on smart grid that relates to energy generation, transmission, distribution, and delivery as well as theories, technologies, design, policies, and implementation of smart grid. Topics include: smart sensing, communication, and control in energy systems; advanced metering infrastructure; energy management in buildings and home automation; smart grid applications to plug-in vehicles and low-carbon transportation alternatives; cyber and physical security systems; microgrids and distributed energy resources; demand response and real-time pricing; and intelligent and outage management systems.
- A Short Course on “Wind Energy Technology, Interconnection and Integration” was developed to provide an introduction to the underlying technology of wind turbine generators and wind power plants, how they are modeled for power system analysis purposes for planning and operating studies, and an introduction to using actual models in simulation programs. This course is targeted towards power systems engineering and management personnel from utilities, RTOs, ISOs, and ITCs as well as consultants, manufacturers and developers involved with the evaluation and planning of the interconnection and operation of new wind plants. The students and professors who are working in the field of wind energy and technology will also benefit from this study course.

6. Recommendations

The project team would like to make the following recommendations based on the research and development performed in this project.

- The WINS software can be applied to perform a comprehensive large-scale wind energy integration analysis with/without transmission constraints. The sensitivity analyses of fuel price, wind energy production, load, carbon cost, and load shedding should be implemented to study the impact of volatility of major parameters on the simulated wind integration results.
- The electricity market structure, involving generally a pool, a futures market and a bilateral trading floor, was designed before the large integration of non-dispatchable sources, particularly wind power. There is a need to address the suitability of the current electricity market structure for producers relying on non-dispatchable energy sources. Considering the intrinsic variability and uncertainty of the production level of non-dispatchable sources, appropriate changes in the current market structure are needed to adapt such structure to an increasingly non-dispatchable generation mix. To efficiently integrate non-dispatchable production, the following questions regarding market design and organization need to be answered: (1) Which is the most appropriate time framework to clear short-term electricity markets? Is it a day-ahead horizon as today, or a shorter one? (2) Should the algorithms to clear such markets be deterministic or stochastic? How should prices be derived? (3) How much reserves should be scheduled to cope with the variable and uncertain nature of renewable non-dispatchable producers? Who should pay for such reserves? (4) How the transmission infrastructure should be expanded and operated to avoid bottlenecks that hinder the integration of renewable non-dispatchable resources?

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Appendices

Appendix A: WINS User Manual

- User Manual, Wind INtegration Simulator (WINS), Illinois Institute of Technology, August 2012.

Appendix B: Journal and Conference Publications

- 1) Wei Tian, Mohammad Shahidehpour, Zuyi Li, Analysis of 2030 Large-Scale Wind Energy Integration in the Eastern Interconnection Using WINS, The Electricity Journal, Volume 24, Issue 8, October 2011, Pages 71-87
- 2) S. Kamalinia, M. Shahidehpour, and A. Khodaei, "Security-constrained expansion planning of fast-response units for wind integration," Electric Power Systems Research, vol.81, no.1, pp.107-116, January 2011
- 3) S. Kamalinia and M. Shahidehpour, "Generation expansion planning in wind-thermal power systems," IET Generation, Transmission & Distribution, vol.4, no.8, pp.940-951, August 2010
- 4) M. Khodayar, M. Barati, and M. Shahidehpour, "Integration of High Reliability Distribution System in Microgrid Operation," IEEE Transactions on Smart Grid, Vol. 3, 2012
- 5) A. Khodaei, M. Shahidehpour, "Microgrid-based Co-optimization of Generation and Transmission Planning in Power Systems," IEEE Transactions on Power Systems, Vol. 27, 2012
- 6) M. Khodayar and M. Shahidehpour, "Stochastic Price-based Coordination of Intra-hour Wind Energy and Storage in a Generation Company," IEEE Transactions on Sustainable Energy, 2012
- 7) H. Wu, M. Shahidehpour, and A. Al-Abdulwahab, "Hourly Demand Response in Day-ahead Scheduling for Managing the Variability of Renewable Energy," IET Journal on Generation, Transmission & Distribution, 2012
- 8) A. Khodaei, M. Shahidehpour, L. Wu, and Z. Li, "Coordination of Short-Term Operation Constraints in Multi-Area Expansion Planning," IEEE Transactions on Power Systems, Vol. 27, 2012
- 9) C. Sahin, M. Shahidehpour, I. Erkmén, "Allocation of Hourly Reserve versus Demand Response for Security-Constrained Scheduling of Stochastic Wind Energy," IEEE Transactions on Sustainable Energy, 2012
- 10) M. Khodayar, L. Wu, and M. Shahidehpour, "Hourly Coordination of Electric Vehicle Operation and Volatile Wind Power Generation in SCUC," IEEE Transactions on Smart Grid, Vol. 3, No. 3, pp. 1271-1279, Sept. 2012
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- 13) C. Sahin, M. Shahidehpour, and I. Erkmén "Generation Risk Assessment in Volatile Conditions with Wind, Hydro, and Natural Gas Units" Applied Energy, Vol. 96, pp. 4-11, Aug. 2012
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- 15) A. Khodaei and M. Shahidehpour, "Security-Constrained Transmission Switching with Voltage Constraints," International Journal of Electrical Power and Energy Systems, Vol. 35, No. 1, pp. 74-82, Feb. 2012
- 16) A. Khodaei, M. Shahidehpour, and S. Bahramirad, "SCUC With Hourly Demand Response Considering Intertemporal Load Characteristics," IEEE Transactions on Smart Grid, Vol. 2, No. 3, pp. 564-571, Sept. 2011
- 17) L. Wu and M. Shahidehpour, "Optimal Coordination of Stochastic Hydro and Natural Gas Supplies in Midterm Operation of Power Systems," IET Journal on Generation, Transmission & Distribution, Vol. 5, No. 5, pp. 577-587, May 2011
- 18) C. Liu, M. Shahidehpour, J. Wang, "Coordinated Scheduling of Electricity and Natural Gas Infrastructures with a Transient Model for Natural Gas Flow," Chaos (American Institute of Physics), Vol. 21, pp. 025102-1 through 025102-12, May 2011
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Wind INtegration Simulator (WINSTM)

User Manual

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1 Introduction

This manual is to introduce the web-based Graphical User Interface (GUI) for WINS. The Wind INtegration Simulator (WINS) would simulate the actual operation of power systems with the integration of volatile wind generation. The users of WINS are entities with full information of the system, such as the Independent System Operators (ISOs). The ISO has the overall information about the system and the market. In addition, generator and transmission line unavailability is considered in WINS and wind deliverability is analyzed for solutions.

WINS simulates the actual market operations which is based on the security-constrained unit commitment (SCUC) with full AC transmission and voltage constraints considered. The computational engine of WINS is written in Microsoft Visual C++, and the Graphical User Interface (GUI) is written in Microsoft Visual C# and ASP.NET. The database is based on ORACLE and can be extended to include other database formats as well. Microsoft Excel is used for the downloading reports.

WINS was first developed in 2002, when it was called POver Market Simulator (POMS). However, numerous modifications and improvements have been introduced to the software based on its applications to various industrial projects.

2 WINS Installation

To use the web-based WINS, a user only needs to have an internet browser. The flowing discussion applies to the server side installation.

2.1 Hardware Requirements

- The Demo version of WINS needs at least 300MB of hard disk space.
- RAM: 512MB or higher
- Screen resolution: 1024×768 pixels or higher

2.2 Software Requirements

- WINS runs in Windows 2003 Server environment (32-bit or 64-bit).
- Internet Browser: Microsoft IE, Mozilla Firefox or Google Chrome.
- Microsoft Excel (version 2000 or version 2003) has to be installed.
- Microsoft .NET Framework 2.0 has to be installed.
- Oracle 11g ODAC 11.1.0.6.21 with Oracle Developer Tools (ODT) for Visual Studio has to be installed.

2.3 Install Microsoft .NET Framework 2.0

If the computer has been installed with Microsoft Visual Studio 2005, Microsoft .NET Framework 2.0 is already installed and this step can be skipped. Otherwise, search "Microsoft .NET Framework Version 2.0 Redistributable Package" on WEB and users will find "dotnetfx.exe" on microsoft.com. Download and double click it to install

Microsoft .NET Framework 2.0.

2.4 Install Oracle Data Access Components

Unzip "ODTwithODAC1110621.zip" and double click "setup.exe" to install Oracle Data Access Components. After installation, copy "sqlnet.ora" and "tnsnames.ora" files to corresponding directory. Modify the contents of "sqlnet.ora" and "tnsnames.ora", if necessary.

2.5 Install SCUC

- SCUC exe file: Create "C:\WINS\" directory and put SCUC project in it.
- Data importer: Copy "oracle_ctl.bat", " pre_load.sql", " post_load.sql" and directory "Oracle" which has a lot of "ctl" files to "C:\WINS\" directory.

2.6 Install WINS

- Use Visual Studio WebSetup project to deploy the WINS to the virtual directory to publish the website. The address of WINS is: <http://216.47.134.239/WINS>

Note: Input data can be entered or modified through either web interface or database management tool. Database in Oracle can be accessed by "SQL*Plus" distributed with ODAC or "PL/SQL Developer" developed by a third company.

3 WINS Functions

Functions in WINS are presented here and various operations are explained.

3.1 Login

Enter "<http://216.47.134.239/WINS>" in the URL address bar of an internet browser to access WINS. The Login page displays as follows:

By clicking the [Please log in](#) Button, a user can go to the case management page with the following log information:

"User Name": doetest

"Password": doetest

3.2 Manage Case

The case management page shown above lists all the cases which can be accessed by the account "doetest". A user can modify the basic case information or delete a case by clicking the "Edit" or "Delete" button in front of each case. By clicking the "Add Case" button, a user can build a new case. By clicking the "Case Name" of each case, a user can choose one case and begin to study the case.

3.2.1 Modify Case

By clicking the "Edit" button of a case, the following two columns of the case could be modified:

"Case Name" ---- name of the selected case;

"Case Description" ---- detailed comments of the selected case;

	Delete	Case Name	Case Description	# of Bus	# of Branch	# of Unit	Capacity (MW)	Created Time	Last Run Time
Update Case	Delete	IEEE118NoWind_AC	IEEE118NoWind_AC	118	186	79	9388	7/18/2012 10:40:09 AM	8/6/2012 10:54:12 AM
Edit	Delete	IEEE118Wind_AC	IEEE118Wind_AC	118	186	79	11298	7/18/2012 1:15:15 PM	7/18/2012 1:15:15 PM
Edit	Delete	IEEE118WindHydro_AC	IEEE118WindHydro_AC	122	181	80	9588	7/18/2012 2:46:09 PM	7/18/2012 2:46:09 PM

Add Case

By clicking the "Update" or "Cancel" button, a user can choose whether or not to accept the modification done before.

The other columns shown below could not be modified in the case management stage, which reflects the actual information during the case study stage.

"Created Time" ---- date when the selected case was created;

"Last Run Time" ---- date when the selected case was executed;

"# of Buses" ---- the total number of buses of the system of the selected case;

"# of Branches" ---- the total number of branches of the system of the selected case;

"# of Units" ---- the total number of generation units of the system of the selected case;

"Capacity (MW)" ---- the total installed capacity of the system of the selected case;

3.2.2 Delete Case

By clicking the "Delete" button in front of a case, a dialog box will pop-up to ask whether a user really wants to delete the selected case as shown below.

A user can click the "OK" button to commit the delete operation, or click the "Cancel" button to cancel the delete operation.

3.2.3 Add Case

Click the "Add Case" button, and input the Case Name and Case Description for the new case. A user can also choose to build a new base based on an existing case by checking the "Base on Case" checkbox, then click the "Insert" button to add the new case to the database. A user can also click the "Cancel" button to discard the new case.

3.2.4 Choose Case

A user can choose a case to study by clicking the "Case Name" of the case, and the detailed case information will be displayed in the corresponding pages.

3.3 Site Map of WINS

The Site Map of WINS includes three areas: TreeView, Basic links, and Main content area. By clicking the "My Account" button, a user can reset the password for the account. The "Sign Out" button is placed on the right top of the site map for a user to log out of the WINS. Below the selected case name shows the site map path of current page, which provides a straightforward guidance for the user to understand the logic relationship of case information.

3.4 Inputs

Through the TreeView under the "Inputs" node, a user can view and modify all the following input data of WINS.

- Area and Owner: Area, Owner and Zone information of selected case.
- GENCOs, TRANSCOs, DISCOs Input: information related to market participants (GENCOs, TRANSCOs, and DISTCOs)
- System Limits: hourly system load, loss and spinning/operating reserve

3.4.1 Inputs – Area and Owner

Go to *Home->Inputs ->Area and Owner* to view the list of area, zone, and market participant entities of the system.

The screenshot displays the WINS web application interface. The sidebar on the left shows a tree view with 'Inputs' expanded, containing sub-items like 'Area and Owner', 'GENCOs Input', 'TRANSCOs Input', and 'DISCOs Input'. The main content area is titled 'IEEE118WithWind_AC' and contains three tables for management:

Area Management			Owner Management			Zone Management		
Area Name	Area ID		Owner Name	OWNEROID	OWNERTYPE	NAME	ZONEID	
Area1	0	Edit Delete	DISTCO1	201	DISTCO	Zone1	1	Edit Delete
Area2	1	Edit Delete	DISTCO2	202	DISTCO	Zone2	2	Edit Delete
Area3	2	Edit Delete	DISTCO3	203	DISTCO	Zone3	3	Edit Delete
Area4	3	Edit Delete	DISTCO4	204	DISTCO			
		Edit Delete	DISTCO5	205	DISTCO			
		Edit Delete	DISTCO6	206	DISTCO			
		Edit Delete	GENCO1	1	GENCO			
		Edit Delete	GENCO2	2	GENCO			
		Edit Delete	GENCO3	3	GENCO			
		Edit Delete	TRANSCO1	101	TRANSCO			
		Edit Delete	TRANSCO2	102	TRANSCO			
		Edit Delete	TRANSCO3	103	TRANSCO			
		Edit Delete	TRANSCO4	104	TRANSCO			

The "Add New Area" button allows a user to add more Areas to the current system. The "Edit" and "Delete" buttons in front of each existing area allow a user to edit or delete the chosen area information. The "Edit" operation allows a user to edit the name of the area, while the "Delete" operation will delete the area and all the components such as units, buses, and branches corresponding to the area in the system.

The "Add New Owner" button allows a user to add more Owners to the current system. The "Edit" and "Delete" buttons in front of each existing owner allow a user to edit or delete the chosen owner information. The "Edit" operation allows a user to edit the name, and choose the owner type (GENCO, TRANSCO or DISTCO) of the owner, while the "Delete" operation will delete the owner and all the components such as units, buses, and branches corresponding to the owner in the system.

The "Add New Zone" button allows a user to add more Zones to the current system. The "Edit" and "Delete" buttons in front of each existing zone record allow a user to edit or delete the chosen zone information. The "Edit" operation allows a user to edit the name of the zone, while the "Delete" operation will delete the zone and all the components such as units, buses, and branches corresponding to the zone from the system.

3.4.2 Inputs – GENCOs Input

Go to *Home->Inputs ->GENCOs Input* to view the overall information of the GENCOs. Five major categories of units are available: fossil, combined cycle, hydro, pumped-storage and wind units.

This page displays the list of GENCOs, and the statistic information about the numbers of different type of units belonging to each GENCO. The "Download Data" button allows users to download the GENCOs related data listed in the table.

The screenshot shows the WINS application interface. The breadcrumb navigation is *Home > Inputs > GENCOs Input*. The page title is *IEEE118WithWind_AC*. The left sidebar shows the navigation menu with *Inputs > GENCOs Input* selected. The main content area displays a table with the following data:

Owner	number of Fossil Units	number of Combined Cycle Units	number of Hydro Units	number of Pumped Storage Units	number of Wind Units
GENCO1	11	5	3	0	1
GENCO2	39	4	4	0	0
GENCO3	4	3	0	3	2

Go to *Home->Inputs ->GENCOs Input->Fossil Units* to view the detailed information on each fossil unit of the system. Besides, by selecting the different items in the dropdown list on the top left of the fossil units table, a user can choose to display the fossil units of individual GENCOs or all the fossil units. The "Download Data" button allows a user to download the detailed fossil units related data listed in the table. The "Add New Unit" button allows a user to add more fossil units to the current system. The "Edit" and "Delete" buttons in front of each existing fossil unit record allow a user to edit or delete the chosen unit information. The "Edit" operation allows a user to edit the detailed information of the selected unit, while the "Delete" operation will delete the unit from the system.

Unit Name	Area Name	Owner Name	Plant	Bus No	Unit ID	Min Capacity (MW)	Max Capacity (MW)	Min Capacity (MVar)	Max Capacity (MVar)	Min Up Time (Hours)	Min Down Time (Hours)	Ramp Up (MW/hour)	Ramp Down (MW/hour)	Quick Start Capability (MW)	Max Sust. Ramp (MW/min)
TG01	Area2	GENCO3	Plant D	4	1	5.00	30.00	-300.00	300.00	1	1	15.00	15.00	30.00	3
TG02	Area1	GENCO3	Plant D	6	1	5.00	30.00	-13.00	50.00	1	1	15.00	15.00	30.00	3
TG03	Area1	GENCO1	Plant E	8	1	5.00	30.00	-300.00	300.00	1	1	15.00	15.00	30.00	3
TG04	Area1	GENCO1	Plant D	10	1	150.00	300.00	-147.00	200.00	8	8	100.00	100.00	0.00	2
TG05	Area2	GENCO3	Plant D	12	1	100.00	300.00	-35.00	120.00	8	8	100.00	100.00	0.00	2
TG06	Area1	GENCO3	Plant D	13	1	10.00	30.00	-10.00	30.00	1	1	15.00	15.00	30.00	3
TG07	Area3	GENCO1	Plant E	15	1	25.00	100.00	-18.00	50.00	5	5	30.00	30.00	0.00	3
TG08	Area2	GENCO1	Plant D	19	1	5.00	30.00	-8.00	24.00	1	1	15.00	15.00	30.00	3
TG09	Area4	GENCO1	Plant D	24	1	5.00	30.00	-300.00	300.00	1	1	15.00	15.00	30.00	3
TG10	Area6	GENCO2	Plant D	25	1	100.00	300.00	-47.00	140.00	8	8	100.00	100.00	0.00	2

The description of individual columns of the fossil unit table is as follows:

Unit Name	unit name (string, no space)
Area Name	area name (string, no space)
Owner Name	owner name (string, no space)
Plant	plant name (string, no space)
Bus No	bus number where the unit is located (long integer)
Unit ID	unit ID (string, no space)
Min Capacity	minimum real power capacity (MW) (double)
Max Capacity	maximum real power capacity (MW) (double)
Min Capacity	minimum reactive power capacity (MVar) (double)
Max Capacity	maximum reactive power capacity (MVar) (double)
Min Up Time	minimum on-operation time (hour, >0) (integer)
Min Down Time	minimum off-operation time (hour, >0) (integer)
Ramp Up	ramping up rate (MW/hour). Less than or equal to MSR (double)
Ramp Down	ramping down rate (MW/hour). Less than or equal to MSR (double)
Quick Start Capability	quick start capability (MW) (double)
Max Sust. Ramp	maximum sustained ramping rate (MW/min) (double)
Number of Minutes	number of minutes for MSR (Minutes) (integer)
Initial Hours	initial operating time (hour, >0 ON, <0 OFF) (integer)
Initial MW	initial operating MW (double)
Fuel Type	fuel type (string)
Fuel Price	fuel price (\$/MBtu) (double)
MBtu/MW Curve	heat rate curve index (long integer)
Startup Fuel Type	startup fuel type (string)

Startup Fuel Price	startup fuel price (\$/MBtu) (double)
Startup Fuel Curve	startup fuel curve index (MBtu consumption as a function of startup hours) (long integer)
Shutdown Fuel Type	shutdown fuel type (string, take values defined in Sheet "Global Definition")
Shutdown Fuel Price	shut down fuel price (\$/MBtu) (double)
SO2 Curve	SO2 emission curve index (long integer)
NOx Curve	NOx emission curve index (long integer)
Ramp Up Curve	ramp up curve index (long integer)
Ramp Up Time	ramp up time (Minutes) (integer)
Ramp Down Curve	ramp up curve index (long integer)
Ramp Down Time	ramp down time (Minutes) (integer)

When a user clicks any "curve" data hyperlink in the table, a new page will pop up to show the detailed curve information. For example, by clicking the "MBtu/MW Curve" data "10001", the following new page shows the heat rate curve of Unit "TG1". A user can modify the parameters for the heat rate curve by changing the data in the textboxes and clicking the "Update" button to commit the changes.

Go to *Home->Inputs ->GENCOs Input->Combined Cycle Units* to view the detailed information on each combined cycle unit in the system. Besides, by selecting the different items in the dropdown list on the top left of the combined cycle units table, a user can choose to display the units of individual GENCOs units or all the units. The "Download Data" button allows a user to download the detailed combined cycle units related data listed in the table. The "Add New Unit" button allows a user to add more combined cycle units to the current system. The "Edit" and "Delete" buttons in front of each existing combined cycle unit record allow a user to edit or delete the chosen unit information. The "Edit" operation allows a user to edit the detailed information of the selected unit, while the "Delete" operation will delete the unit from the system.

The screenshot shows the WINS application interface. The breadcrumb trail at the top reads: *Home > Inputs > GENCOs Input > Combined Cycle Units*. Below the breadcrumb trail, there are buttons for "All GenCOs", "Download Data", and "Add New Unit". The main table displays the following data:

	Delete	Unit Name	Area Name	Owner Name	Plant	Bus No	Unit Id	Min Capacity (MW)	Max Capacity (MW)	Min Capacity (MW)	Max Capacity (MW)	Min Time (Hours)	Max Time (Hours)	Ramp Up (MW/hour)	Ramp Down (MW/hour)	Quick Start (MW)
Edit Select	Delete	CC1	Area0	GENCO01	0	12	C1	5.00	75.00	-75.00	75.00	2	3	75.00	75.00	75.00
Edit Select	Delete	CC2	Area0	GENCO02	0	61	C1	5.00	75.00	-75.00	75.00	2	3	75.00	75.00	75.00
Edit Select	Delete	CC3	Area0	GENCO03	0	60	C1	5.00	75.00	-75.00	75.00	2	3	75.00	75.00	75.00
Edit Select	Delete	CC4	Area0	GENCO04	0	66	C1	5.00	100.00	-100.00	100.00	2	3	100.00	100.00	100.00
Edit Select	Delete	CC5	Area0	GENCO05	0	49	C1	5.00	75.00	-75.00	75.00	2	3	75.00	75.00	75.00
Edit Select	Delete	CC6	Area0	GENCO06	0	44	C2	5.00	75.00	-75.00	75.00	2	3	75.00	75.00	75.00
Edit Select	Delete	CC7	Area0	GENCO07	0	59	C1	5.00	100.00	-100.00	100.00	2	3	100.00	100.00	100.00
Edit Select	Delete	CC8	Area0	GENCO08	0	61	C2	5.00	100.00	-100.00	100.00	2	3	100.00	100.00	100.00
Edit Select	Delete	CC9	Area0	GENCO09	0	80	C1	5.00	100.00	-100.00	100.00	2	3	100.00	100.00	100.00
Edit Select	Delete	CC10	Area0	GENCO10	0	113	C1	5.00	100.00	-100.00	100.00	2	3	100.00	100.00	100.00

Different from other units, there is a "Select" button in front of each existing combined cycle unit record. When a user clicks to choose different combined cycle unit, all its modes will be displayed correspondingly in the mode table below the unit table on the same page. For example, by clicking the "Select" button of unit "CC1", the following page shows all the modes that belong to "CC1".

The "Add New Mode" button allows a user to add more modes to the selected combined cycle unit. The "Edit" and "Delete" buttons in front of each existing mode record allow a user to edit or delete the chosen mode of the selected unit. The "Edit" operation allows a user to edit the detailed information of the mode, while the "Delete" operation will delete the mode from the unit.

The description of individual columns of the combined cycle unit table is as follows:

Unit Name	unit name (string, no space)
Area Name	area name (string, no space)
Owner Name	owner name (string, no space)
Plant	plant name (string, no space)
Bus No	bus number where the unit is located (long integer)
Unit ID	unit ID (string, no space)
Min Capacity	minimum real power capacity (MW) (double)
Max Capacity	maximum real power capacity (MW) (double)
Min Capacity	minimum reactive power capacity (MVar) (double)
Max Capacity	maximum reactive power capacity (MVar) (double)
Min Up Time	minimum on-operation time (hour, >0) (integer)
Min Down Time	minimum off-operation time (hour, >0) (integer)
Ramp Up	ramping up rate (MW/hour). Less than or equal to MSR (double)

Ramp Down	ramping down rate (MW/hour). Less than or equal to MSR (double)
Quick Start Capability	quick start capability (MW) (double)
Max Sust. Ramp	maximum sustained ramping rate (MW/min) (double)
Number of Minutes	number of minutes for MSR (Minutes) (integer)
Initial Mode	initial operating mode (0 stands for OFF)
Initial Hours	initial operating time (hour, >0 ON, <0 OFF) (integer)
Initial MW	initial operating MW (double)
Number of Mode	number of modes (integer)
Number of CT	number of CT (integer)
Number of ST	number of ST (integer)
Fuel Type	fuel type (string)
Fuel Price	fuel price (\$/MBtu) (double)
MBtu/MW Curve	heat rate curve index (long integer)

CT Information:

CT Startup Fuel Type	startup fuel type (string)
CT Startup Fuel Price	startup fuel price (\$/MBtu) (double)
CT Startup Fuel Curve	startup fuel curve index (MBtu consumption as a function of startup hours) (long integer)
CT Shutdown Fuel Type	shutdown fuel type (string, take values defined in Sheet "Global Definition")
CT Shutdown Fuel Price	shut down fuel price (\$/MBtu) (double)

ST Information:

ST Startup Fuel Type	ST startup fuel type (string)
ST Startup Fuel Price	ST startup fuel price (\$/MBtu) (double)
ST Startup Fuel Curve	ST startup fuel curve index (MBtu as a function of startup hours) (long integer)
ST Shutdown Fuel Type	ST shutdown fuel type (string)
ST Shutdown Fuel Price	ST shutdown fuel price (\$/MBtu) (double)

The description of individual columns of mode table is as follows:

Mode No	mode number (integer, positive)
Number of CT	number of CTs in the mode (integer, non-negative)
Number of ST	number of STs in the mode (integer, non-negative)
Min Capacity	minimum real power capacity of the mode (MW) (double)
Max Capacity	maximum real power capacity of the mode (MW) (double)
Min Capacity	minimum reactive power capacity of the mode (MVAR) (double)
Max Capacity	maximum reactive power capacity of the mode (MVAR)

	(double)
Ramp Up	ramping up rate of the mode (MW/hour). Less than or equal to MSR (double)
Ramp Down	ramping down rate of the mode (MW/hour). Less than or equal to MSR (double)
MBtu/MW Curve	heat rate curve index of the mode (long integer)
Nox Curve	NOx emission curve of the mode (long integer)

When a user clicks any "curve" data hyperlink in the table, a new page will pop up to show the detailed curve information. The curve types of combined cycle units are very similar to those of fossil units.

Go to *Home->Inputs ->GENCOs Input->Hydro Units* to view the detailed information on each hydro unit of the system. Besides, by selecting the different items in the dropdown list on the top left of the hydro units table, a user can choose to display the units of individual GENCOs or all the hydro units. The "Download Data" button allows a user to download the detailed hydro units related data listed in the table. The "Add New Unit" button allows a user to add more hydro units to the current system. The "Edit" and "Delete" buttons in front of each existing hydro unit record allow a user to edit or delete the chosen unit information. The "Edit" operation allows a user to edit the detailed information of the selected unit, while the "Delete" operation will delete the unit from the system.

WINS

IEEE118WithWind_AC

Home > Inputs > GENCOs Input > Hydro Units

All GENCOs Download Data Add New Unit

	Delete	Unit Name	Plant	Owner Name	Unit ID	Bus No	Min Capacity (MW)	Max Capacity (MW)	Min Q/C (MVar)	Max Q/C (MVar)	Initial Hours	Water Power Conversion Curve	Startup Cost Curve	Natural Inflow (Mm ³ /h)	Minimum Discharge (Mm ³ /h)	Upper Limit Discharge (Mm ³ /h)	Upper Limit Inflow (Mm ³ /h)
Edit	Delete	H1	plant0	GENCO2	H1	39	-9.00	70.00	1	1	0	16031	26001	-4.00	0.00	1.00	30.0
Edit	Delete	H2	plant0	GENCO2	H1	24	-4.00	70.00	1	1	0	16032	26002	5.00	0.00	1.00	30.0
Edit	Delete	H3	plant0	GENCO2	H1	25	-17.00	115.00	1	1	0	16033	26003	2.00	0.00	1.00	20.0
Edit	Delete	H4	plant0	GENCO2	H1	89	-20.00	194.00	1	1	0	16034	26004	8.25	0.00	1.00	20.0
Edit	Delete	H5	plant0	GENCO3	H1	90	-9.00	80.00	1	1	0	16035	26005	5.00	0.00	1.00	30.0
Edit	Delete	H6	plant0	GENCO3	H1	91	-2.00	60.00	1	1	0	16036	26006	2.00	0.00	1.00	30.0
Edit	Delete	H7	plant0	GENCO3	H1	103	-19.00	120.00	1	1	0	16037	26007	1.22	0.00	-1.50	-20.0

The description of individual columns of the hydro unit table is as follows:

Unit Name	unit name (string, no space)
Plant	plant name (string, no space)
Owner Name	owner name (string, no space)
Unit ID	unit ID (string, no space)
Bus No	bus number where the unit is located (long integer)
Min Capacity	minimum real power capacity (MW) (double)
Max Capacity	maximum real power capacity (MW) (double)
Min Capacity	minimum reactive power capacity (MVAR) (double)
Max Capacity	maximum reactive power capacity (MVAR) (double)
Initial Hours	initial operating time (hour, >0 ON, <0 OFF) (integer)
Water Power Conversion Curve	water to power conversion curve index (long integer)
Startup Cost Curve	start up cost curve index (long integer)

Natural Inflow	natural inflow (Hm ³ /h) (double)
Spillage	maximum spillage (Hm ³ /h) (double)
Lower Limit Discharge	lower limit of water discharge (Hm ³ /h) (double)
Upper Limit Discharge	upper limit of water discharge (Hm ³ /h) (double)
Initial Reservoir Volume	initial reservoir volume level (Hm ³) (double)
Terminal Reservoir Volume	terminal reservoir volume level (Hm ³) (double)
Lower Limit Reservoir Volume	lower limit of reservoir volume (Hm ³) (double)
Upper Limit Reservoir Volume	upper limit of reservoir volume (Hm ³) (double)

When a user clicks any "curve" data hyperlink in the table, a new page will pop up to show the detailed curve information. There is a unique curve of hydro unit: Water Power Conversion Curve, which is a quadratic function showing the relationship between the natural water flow and the power generation of the hydro unit. For example, by clicking the hyperlink "16001", the following new page shows the water power conversion curve of Unit "H1". User can modify the parameters for the curve by changing the data in the textboxes and clicking the "Update" button to commit changes.

Go to *Home->Inputs ->GENCOs Input->Catchment* to view the detailed information on each hydro catchment of the system. The "Download Data" button allows a user to download the detailed catchment related data listed in the table. The "Add New Catchment" button allows a user to add more hydro catchment to the current system, which requires at least two different hydro units existing in the current system. The "Edit" and "Delete" buttons in front of each existing hydro catchment record allow a user to edit or delete the chosen catchment information. The "Edit" operation allows a user to edit the up stream and down stream hydro units of the selected catchment, while the "Delete" operation will delete the hydro catchment from the system.

WINS

IEEE118WithWind_AC

Home > Inputs > GENCOs Input > Catchments

Download Data Add New Catchment

	Catchment Index	Up Stream Unit	Down Stream Unit	Discharge Delay Time (Hours)
Edit Delete	1	H1	H3	2
Edit Delete	1	H2	H3	2
Edit Delete	1	H3	H4	2
Edit Delete	1	H4	N/A	2
Edit Delete	2	H5	H7	2
Edit Delete	2	H6	H7	2
Edit Delete	2	H7	N/A	2

The description of individual columns of the catchment table is as follows:

Catchment Index	hydro catchment index (integer)
Up Stream Unit	up stream hydro unit name of catchment (string, no space)
Down Stream Unit	down stream hydro unit name of catchment (string, no space)
Discharge Delay Time	discharge delay time from up to down stream unit (Hour) (integer)

Go to *Home->Inputs ->GENCOs Input->Pumped Storage Units* to view the detailed information on each pumped storage unit of the system. Besides, by selecting the different items in the dropdown list on the top left of the pumped storage units table, a user can choose to display each individual GENCO's units list or all the pumped storage units. The "Download Data" button allows a user to download the detailed pumped storage units related data listed in the table. The "Add New Unit" button allows a user to add more pumped storage units to the current system. The "Edit" and "Delete" buttons in front of each existing pumped storage unit record allow a user to edit or delete the chosen unit information. The "Edit" operation allows a user to edit the detailed information of the selected unit, while the "Delete" operation will delete the unit from the system.

	Delete	Unit Name	Plant	Owner Name	Unit ID	Bus No	Min Capacity (MW)	Max Capacity (MW)	Min Capacity (MVAR)	Max Capacity (MVAR)	Min Up Time (Hours)	Min Down Time (Hours)	Initial Loading Status	Initial Hour	Lower Limit Generation (MW/h)	Upper Limit Generation (MW/h)	Load Factor
Edit	Delete	PS1	Plant 0	GENCO3	S1	56	34.00	100.00	-20.00	100	1	1	0	1	5.00	15.00	8
Edit	Delete	PS2	Plant 0	GENCO3	S1	77	34.00	100.00	-20.00	100	1	1	0	1	5.00	15.00	8
Edit	Delete	PS3	Plant 0	GENCO3	S1	69	34.00	204.00	-34.00	204	1	1	0	1	7.00	20.00	10

The description of individual columns of the pumped storage unit table is as follows:

Unit Name	unit name (string, no space)
Plant	plant name (string, no space)
Owner Name	owner name (string, no space)
Unit ID	unit ID (string, no space)
Bus No	bus number where the unit is located (long integer)
Min Capacity	minimum real power capacity (MW) (double)
Max Capacity	maximum real power capacity (MW) (double)
Min Capacity	minimum reactive power capacity (MVAR) (double)
Max Capacity	maximum reactive power capacity (MVAR) (double)
Min Up Time	minimum on-operation time (hour, >0) (integer)
Min Down Time	minimum off-operation time (hour, >0) (integer)
Initial Loading Status	initial operating state (0: idle, 1: generating, -1: pumping) (integer)

Initial Hours	initial operating time (hours, nonnegative) (integer)
Lower Limit Generation Discharge	generation discharge lower limit (Hm3/h) (double)
Upper Limit Generation Discharge	generation discharge upper limit (Hm3/h) (double)
Lower Limit Pumping Discharge	pumping discharge lower limit (Hm3/h) (double)
Upper Limit Pumping Discharge	pumping discharge upper limit (Hm3/h) (double)
Initial Upstream Reservoir Volume	initial upstream reservoir volume level (Hm3) (double)
Terminal Upstream Reservoir Volume	terminal upstream reservoir volume level (Hm3) (double)
Lower Limit Upstream Reservoir Volume	lower limit of upstream reservoir volume (Hm3) (double)
Upper Limit Upstream Reservoir Volume	upper limit of upstream reservoir volume (Hm3) (double)
Initial Downstream Reservoir Volume	initial downstream reservoir volume level (Hm3) (double)
Terminal Downstream Reservoir Volume	terminal downstream reservoir volume level (Hm3) (double)
Lower Limit Downstream Reservoir Volume	lower limit of downstream reservoir volume (Hm3) (double)
Upper Limit Downstream Reservoir Volume	upper limit of downstream reservoir volume (Hm3) (double)
Water Power Conversion Curve Generation	water to power conversion curve index (generation mode) (long integer)
Water Power Conversion Curve Pumping	water to power conversion curve index (pumping mode) (long integer)
Generation Min ON	minimum operating time in generation mode (integer, positive)
Pumping Min On	minimum operating time in pumping mode (integer, positive)

When a user clicks any "curve" data hyperlink in the table, a new page will pop up to show the detailed curve information. The curve types of pumped storage units for the water power conversion curves in generation and pumping modes are very similar to those hydro units' water power conversion curves.

Go to *Home->Inputs ->GENCOs Input->Wind Units* to view the detailed information on each wind unit of the system. Besides, by selecting the different items in the dropdown list on the top left of the wind units table, a user can choose to display each individual GENCO's units list or all the wind units. The "Download Data" button allows a user to download the detailed wind units related data listed in the table. The "Add New Unit" button allows a user to add more wind units to the current system. The "Edit" and "Delete" buttons in front of each existing wind unit record allow a user to edit or delete the chosen unit information. The "Edit" operation allows a user to edit the detailed information of the selected unit, while the "Delete" operation will delete the unit from the system.

Delete	Unit Name	Owner Name	Unit ID	Bus No	Min Capacity (MW)	Max Capacity (MW)	Min Capacity (MVar)	Max Capacity (MVar)	Wind Power Curve
Edit Delete	W1	GENCO3	W	26	0.00	962.00	-22.50	112.50	2001
Edit Delete	W2	GENCO3	W	77	0.00	500.00	-20.00	100.00	2001
Edit Delete	W3	GENCO3	W	69	0.00	837.50	-33.50	167.50	2001

Description of individual columns of the wind unit table is as follows:

Unit Name	unit name (string, no space)
Plant	plant name (string, no space)
Owner Name	owner name (string, no space)
Unit ID	unit ID (string, no space)
Bus No	bus number where the unit is located (long integer)
Min Capacity	minimum real power capacity (MW) (double)
Max Capacity	maximum real power capacity (MW) (double)
Min Capacity	minimum reactive power capacity (MVAR) (double)
Max Capacity	maximum reactive power capacity (MVAR) (double)
Wind Power Curve	curve index for the time series of wind power

There is a unique curve of wind unit: Wind Power Curve, which is a series of numbers showing the time series of the wind unit power generation percentage of maximum unit capacity. For

example, by clicking the hyperlink "2001", the following new page shows the wind power curve of Unit "W1". User can modify the series data for the curve by clicking the "Edit" button in front of each data record in the table and clicking the "Update" button to commit the changes.

3.4.3 Inputs – TRANSCOs Input

Go to *Home->Inputs ->TRANSCOs Input* to view the overall information of the TRANSCOs.

This page displays the list of TRANSCOs, and the statistic information about the numbers of branches that belong to each TRANSCO. The "Download Data" buttons allow a user to download the TANSOs related data listed in the table.

The screenshot shows the WINS web application interface. The breadcrumb trail at the top reads: [Home](#) > [Inputs](#) > [TRANSCOs Input](#). The left navigation menu is expanded to show the 'TRANSCOs Input' section. The main content area displays a table with the following data:

Owner	Number of Branches
TRANSCO1	50
TRANSCO2	49
TRANSCO3	34
TRANSCO4	53

Below the table, there is a 'Download Data' button for each row.

Go to *Home->Inputs ->TRANSCOs Input->Buses* to view the detailed information on each bus of the system. Besides, by selecting the different items in the dropdown list on the top left of the buses table, a user can choose to display buses of individual TRANSCOs or all the buses. The "Download Data" button allows a user to download the detailed bus related data listed in the table. The "Add New Bus" button allows a user to add more buses to the current system. The "Edit" and "Delete" buttons in front of each existing bus record allow a user to edit or delete the chosen bus information. The "Edit" operation allows a user to edit the detailed information of the selected bus, while the "Delete" operation will delete the bus from the system.

The screenshot shows the WINS application interface. The breadcrumb trail at the top reads: *Home > Inputs > TRANSCOs Input > Buses*. Below this, there is a dropdown menu set to 'All TransCos', a 'Download Data' button, and an 'Add New Bus' button. The main table displays bus data for IEEE118WithWind_AC. The table has 13 columns: Name, Area Name, Zone Name, Owner Name, Bus No, Type, Base KV, Voltage Magnitude (p.u.), Voltage Angle (deg.), G, B, Min Voltage (p.u.), Max Voltage (p.u.), and Status. There are 10 rows of bus data, each with 'Edit' and 'Delete' buttons in the first column.

	Name	Area Name	Zone Name	Owner Name	Bus No	Type	Base KV	Voltage Magnitude (p.u.)	Voltage Angle (deg.)	G	B	Min Voltage (p.u.)	Max Voltage (p.u.)	Status
Edit Delete	BUS1	Area1	Zone1	TRANSCO1	1	0	0.00	0.96	-10.61	0.00	0.00	0.94	1.05	1
Edit Delete	BUS2	Area1	Zone1	TRANSCO1	2	0	0.00	0.97	-9.49	0.00	0.00	0.95	1.04	1
Edit Delete	BUS3	Area1	Zone2	TRANSCO1	3	0	0.00	0.97	-9.95	0.00	0.00	0.95	1.04	1
Edit Delete	BUS4	Area1	Zone1	TRANSCO1	4	2	0.00	1.00	-7.46	0.00	0.00	0.99	1.09	1
Edit Delete	BUS5	Area1	Zone2	TRANSCO1	5	0	0.00	1.00	-7.88	0.00	0.00	0.99	1.09	1
Edit Delete	BUS6	Area1	Zone1	TRANSCO1	6	2	0.00	0.99	-8.36	0.00	0.00	0.97	1.09	1
Edit Delete	BUS7	Area1	Zone2	TRANSCO1	7	0	0.00	0.99	-8.43	0.00	0.00	0.97	1.09	1
Edit Delete	BUS8	Area1	Zone1	TRANSCO1	8	2	0.00	1.02	-3.85	0.00	0.00	0.98	1.09	1
Edit Delete	BUS9	Area1	Zone2	TRANSCO1	9	0	0.00	1.00	0.03	0.00	0.00	0.98	1.09	1
Edit Delete	BUS10	Area1	Zone1	TRANSCO1	10	2	0.00	1.05	4.16	0.00	0.00	0.98	1.09	1

The description of individual columns of the bus table is as follows:

Name	bus name (character, maximum length 20, no space)
Area Name	area name (string)
Zone Name	zone name (string)
Owner Name	owner name (string)
Bus No	bus number (long integer)
Type	bus type (integer, only take the following numbers) <ul style="list-style-type: none"> 0: unregulated (load, PQ) 2: hold voltage within VAR limits (gen, PV) 3: hold voltage and angle (swing, V-Theta) 4: isolated
BaseKV	bus base voltage (kV) (double, non-negative)

Voltage Magnitude	bus voltage magnitude (p.u.) (double, non-negative)
Voltage Angle	bus voltage angle (degree) (double)
GL	shunt conductance (p.u.) (double)
BL	shunt susceptance (p.u.) (double)
Min Voltage Magnitude	minimum bus voltage magnitude (p.u.) (double, non-negative)
Max Voltage Magnitude	maximum bus voltage magnitude (p.u.) (double, non-negative)
Status	bus status (integer: 0 or 1)

Go to *Home->Inputs ->TRANSCOs Input->Branches* to view the detailed information on each branch of the system. Besides, by selecting the different items in the dropdown list on the top left of the branches table, a user can choose to display the branches of individual TRANSCOs or all the branches. The "Download Data" button allows a user to download the detailed branch related data listed in the table. The "Add New Branch" button allows a user to add more branches to the current system. The "Edit" and "Delete" buttons in front of each existing branch record allow a user to edit or delete the chosen branch information. The "Edit" operation allows a user to edit the detailed information of the selected branch, while the "Delete" operation will delete the branch from the system.

IEEE118WithWind_AC

Home > Inputs > TRANSCOs Input > Branches

All TransCos Download Data Add New Branch

	Name	Area Name	Zone Name	Owner Name	From Bus	To Bus	Circuit ID	Status	Resistance (p.u.)	Reactance (p.u.)	Charging (p.u.)	Rate A (\$/MVA)	Rate B (\$/MVA)	Rate C (\$/MVA)	Unit Commit (p.u.)	Line Commit (p.u.)	Line Commit (p.u.)
Edit Delete	BR10	Area1	Zone1	TRANSCOs	4	11	1	1	0.02	0.07	0.02	175.00	175.00	175.00	0.00	0.00	0.00
Edit Delete	BR11	Area1	Zone1	TRANSCOs	5	11	1	1	0.02	0.07	0.02	175.00	175.00	175.00	0.00	0.00	0.00
Edit Delete	BR12	Area1	Zone1	TRANSCOs	31	12	1	1	0.01	0.01	0.01	175.00	175.00	175.00	0.00	0.00	0.00
Edit Delete	BR13	Area1	Zone1	TRANSCOs	2	12	1	1	0.02	0.06	0.02	175.00	175.00	175.00	0.00	0.00	0.00
Edit Delete	BR14	Area1	Zone1	TRANSCOs	3	12	1	1	0.05	0.16	0.04	175.00	175.00	175.00	0.00	0.00	0.00
Edit Delete	BR15	Area1	Zone1	TRANSCOs	7	12	1	1	0.01	0.03	0.01	175.00	175.00	175.00	0.00	0.00	0.00
Edit Delete	BR16	Area1	Zone1	TRANSCOs	11	13	1	1	0.02	0.07	0.02	175.00	175.00	175.00	0.00	0.00	0.00
Edit Delete	BR17	Area1	Zone1	TRANSCOs	12	14	1	1	0.02	0.07	0.02	175.00	175.00	175.00	0.00	0.00	0.00
Edit Delete	BR18	Area1	Zone1	TRANSCOs	13	15	1	1	0.07	0.24	0.04	175.00	175.00	175.00	0.00	0.00	0.00
Edit Delete	BR19	Area1	Zone1	TRANSCOs	14	15	1	1	0.06	0.20	0.05	175.00	175.00	175.00	0.00	0.00	0.00

The description of individual columns of the branch table is as follows:

Name	branch name (character, maximum length 20, no space)
Area Name	area name (string)
Zone Name	zone name (string)
Owner Name	owner name (string)
From Bus (I)	from bus number (long integer)
To Bus (J)	to bus number (long integer)
Circuit ID (CID)	circuit ID (character, maximum length 2)
Status	branch status (integer: 0 or 1)
Resistance (R)	resistance (DEFAULT: 0; p.u.) (double)
Reactance (X)	reactance (DEFAULT: must input; p.u.) (double)
Charging (B)	total branch charging (DEFAULT: 0; p.u.) (double)

Rate A	long term rate, flow limit A (default: 0; MVA) (double)
Rate B	short term rate, flow limit B (default: 0; MVA) (double)
Rate C	emergency rate, flow limit C (default: 0; MVA) (double)
GI	line shunt conductance at from bus side (default: 0; p.u.) (double)
BI	line shunt susceptance at from bus side (default: 0; p.u.) (double)
GJ	line shunt conductance at to bus side (default: 0; p.u.) (double)
BJ	line shunt susceptance at to bus side (default: 0; p.u.) (double)
Length	branch length (default: 0) (double)

Go to *Home->Inputs ->TRANSCOs Input->Transformers* to view the detailed information on each transformer of the system. Besides, by selecting the different items in the dropdown list on the top left of the transformers table, a user can choose to display each individual TRANSCO's transformer list or all the transformers. The "Download Data" button allows a user to download the detailed transformer related data listed in the table. The "Add New Transformer" button allows a user to add more transformers to the current system. The "Edit" and "Delete" buttons in front of each existing transformer record allow a user to edit or delete the chosen transformer information. The "Edit" operation allows a user to edit the detailed information of the selected transformer, while the "Delete" operation will delete the transformer from the system.

	Name	Area Name	Zone Name	Owner Name	From Bus	To Bus	Circuit ID	Type	Resistance (ohm)	Reactance (ohm)	Rate A (MVA)	Rate B (MVA)	Rate C (MVA)	Turns Ratio	Phase Shift (deg.)	TAPMIN	TAPMAX	Angle
Edit Delete	TF1	Area1	Zone1	TRANSCO1	8	9	1	1	0.00	0.03	500.00	500.00	500.00	0.99	0.00	0.00	0.00	0
Edit Delete	TF2	Area1	Zone1	TRANSCO1	20	23	1	1	0.00	0.04	500.00	500.00	500.00	0.96	0.00	0.00	0.00	0
Edit Delete	TF3	Area1	Zone1	TRANSCO1	30	17	1	1	0.00	0.04	500.00	500.00	500.00	0.96	0.00	0.00	0.00	0
Edit Delete	TF4	Area2	Zone2	TRANSCO2	38	37	1	1	0.00	0.04	500.00	500.00	500.00	0.94	0.00	0.00	0.00	0
Edit Delete	TF5	Area2	Zone2	TRANSCO3	63	59	1	1	0.00	0.04	500.00	500.00	500.00	0.96	0.00	0.00	0.00	0
Edit Delete	TF6	Area2	Zone2	TRANSCO3	54	61	1	1	0.00	0.03	500.00	500.00	500.00	0.90	0.00	0.00	0.00	0
Edit Delete	TF7	Area2	Zone2	TRANSCO3	65	66	1	1	0.00	0.04	500.00	500.00	500.00	0.94	0.00	0.00	0.00	0
Edit Delete	TF8	Area2	Zone2	TRANSCO3	68	69	1	1	0.00	0.04	500.00	500.00	500.00	0.94	0.00	0.00	0.00	0
Edit Delete	TF9	Area2	Zone2	TRANSCO4	81	88	1	4	0.00	0.04	500.00	500.00	500.00	0.94	-1.57	0.00	0.00	-15

The description of individual columns of the transformer table is as follows:

Name	transformer name (character, maximum length 20, no space)
Area Name	area name (string)
Zone Name	zone name (string)
Owner Name	owner name (string)
From Bus (I)	from bus number (long integer)
To Bus (J)	to bus number (long integer)
Circuit ID (CID)	circuit ID (character, maximum length 2)
Type	transformer type (integer: 1: Tap changer, 4: Phase shifter)
Resistance (R)	resistance (DEAFULT: 0; p.u.) (double)
Reactance (X)	reactance (DEAFULT: must input; p.u.) (double)
Charging (B)	total branch charging (DEAFULT: 0; p.u.) (double)
Rate A	long term rate, flow limit A (default: 0; MVA) (double)

Rate B	short term rate, flow limit B (default: 0; MVA) (double)
Rate C	emergency rate, flow limit C (default: 0; MVA) (double)
Turns Ratio	fixed tap (default: 1; p.u.) (double)
Phase Shift	fixed phase shifter angle (default: 0; degree) (double)
TAPMIN	minimum tap change (double)
TAPMAX	maximum tap change (double)
ANGLEMIN	minimum phase shifter angle (double)
ANGLEMAX	maximum phase shifter angle (double)

Go to *Home->Inputs ->TRANSCOs Input->Shunt Elements* to view the detailed information on each shunt element of the system. Besides, by selecting the different items in the dropdown list on the top left of the shunt elements table, a user can choose to display the shunt elements of individual TRANSCOs or all the shunt elements. The "Download Data" button allows a user to download the detailed shunts related data listed in the table. The "Add New Shunt" button allows a user to add more shunts to the current system. The "Edit" and "Delete" buttons in front of each existing shunt element record allow a user to edit or delete the chosen shunt information. The "Edit" operation allows a user to edit the detailed information of the selected shunt, while the "Delete" operation will delete the shunt from the system.

WINS

IEEE118WithWind_AC

Home > Inputs > TRANSCOs Input > Shunt Elements

All TransCos Download Data Add New Shunt

Name	Type	Area Name	Zone Name	Owner Name	ID	Bus No	Status	Q (MVar)	Min Q (MVar)	Max Q (MVar)
Edit Delete SC1	Inductor	Area1	Zone1	TRANSCO1	1	5	1	-40.00	-50.00	0.00
Edit Delete SC2	Capacitor	Area2	Zone2	TRANSCO2	1	34	1	14.00	0.00	20.00
Edit Delete SC3	Inductor	Area2	Zone2	TRANSCO2	1	37	1	-25.00	-30.00	0.00
Edit Delete SC4	Capacitor	Area2	Zone2	TRANSCO2	1	44	1	10.00	0.00	20.00
Edit Delete SC5	Capacitor	Area2	Zone2	TRANSCO2	1	45	1	10.00	0.00	20.00
Edit Delete SC6	Capacitor	Area2	Zone2	TRANSCO2	1	46	1	10.00	0.00	20.00
Edit Delete SC7	Capacitor	Area2	Zone2	TRANSCO2	1	48	1	15.00	0.00	20.00
Edit Delete SC8	Capacitor	Area3	Zone3	TRANSCO3	1	74	1	12.00	0.00	20.00
Edit Delete SC9	Capacitor	Area2	Zone2	TRANSCO4	1	79	1	20.00	0.00	30.00
Edit Delete SC10	Capacitor	Area3	Zone3	TRANSCO4	1	82	1	20.00	0.00	30.00

The description of individual columns of the shunt elements table is as follows:

Name	shunt element name (character, maximum length 20, no space)
Type	transformer type (string: Capacitor or Inductor)
Area Name	area name (string)
Zone Name	zone name (string)
Owner Name	owner name (string)
ID	shunt element ID (character, maximum length 2)
BusNo	shunt element bus number (long integer)
Status	shunt element status (integer: 0 or 1)
Q	initial shunt capacitance (default: 0; MVAR) (double)
Min Q	minimum shunt capacitance (default: 0; MVAR) (double)
Max Q	maximum shunt capacitance (default: 0; MVAR) (double)

Go to *Home->Inputs->TRANSCOs Input->HVDC->Current Source Converter* to view the detailed information on each current source converter (CSC) of the HVDC lines of the system. Besides, by selecting the different items in the dropdown list on the top left of the CSC table, a user can choose to display the CSCs of individual TRANSCOs or all the CSCs. The "Download Data" button allows a user to download the detailed CSC related data listed in the table. The "New Current Source Converter" button allows a user to add more CSCs to the current system. The "Edit" and "Delete" buttons in front of each existing CSC record allow a user to edit or delete the chosen CSC information. The "Edit" operation allows a user to edit the detailed information of the selected CSC, while the "Delete" operation will delete the CSC from the system.

The description of individual columns of the CSC table is as follows:

Name	current source converter name (string)
Area Name	area name (string)
Zone Name	zone name (string)
Owner Name	owner name (string)
Group Name	group name of HVDC lines (string)
Type	CSC type (integer, 1 or 2; 1: Rectifier; 2: Inverter)
ACBusNo	AC bus number of the CSC connected to (long integer)
DCBusANo	DC bus A number of the CSC connected to (long integer)
DCBusBNo	DC bus B number of the CSC connected to (long integer)
Status	CSC status (integer: 0 or 1)
MODE	CSC control mode 1 (integer: 0 to 3; 0: blocked; 1: constant DC current; 2: constant power; 3: constant DC voltage)

SELVL	CSC set point for control mode 1 (double)
NB	Number of converter bridges (integer)
RC	Commutating resistance per bridge (double, p.u.)
XC	Commutating reactance per bridge (double, p.u.)
ANG	CSC firing angle (double, degree, default: 15)
ANGMN	CSC minimum firing angle (double, degree, default: 10)
ANGMX	CSC maximum firing angle (double, degree, default: 25)
Turns Ratio	CSC transformer off-nominal turns ratio (double, p.u., default: 1)
TAPMIN	CSC minimum transformer off-nominal turns ratio (double, p.u., default: 0.51)
TAPMAX	CSC maximum transformer off-nominal turns ratio (double, p.u., default: 1.50)
MODE2	CSC control mode 2 (integer: 0 to 3; 0: blocked; 1: constant DC current; 2: constant power; 3: constant DC voltage)
SELVL2	CSC set point for control mode 2 (double)
Min Capacity	CSC minimum real power capacity (double, MW)
Max Capacity	CSC maximum real power capacity (double, MW)
Min Capacity	CSC minimum reactive power capacity (double, MVAR)
Max Capacity	CSC maximum reactive power capacity (double, MVAR)
DC Min Current	CSC minimum DC current limit (double, p.u.)
DC Max Current	CSC maximum DC current limit (double, p.u.)

Go to *Home->Inputs->TRANSCOs Input->HVDC->Voltage Source Converter* to view the detailed information on each voltage source converter (VSC) of the HVDC lines of the system. Besides, by selecting the different items in the dropdown list on the top left of the VSC table, a user can choose to display the VSCs of individual TRANSCOs or all the VSCs. The "Download Data" button allows a user to download the detailed VSC related data listed in the table. The "New Voltage Source Converter" button allows a user to add more VSCs to the current system. The "Edit" and "Delete" buttons in front of each existing VSC record allow a user to edit or delete the chosen VSC information. The "Edit" operation allows a user to edit the detailed information of the selected VSC, while the "Delete" operation will delete the VSC from the system.

Name	Area Name	Zone Name	Owner Name	Group Name	Type	ACBusNo	DCBusA	DCBusB	Status	Mode	SELV1	SELV2	Reactance (p.u.)	Filter Capacity (MW)
Edit Delete VSC1	Area1	Zone1	TRANSCO_DC	DCGROUP1	2	23	-1	1	1	2	0.00	0.00	0.02	-2.00
Edit Delete VSC2	Area1	Zone1	TRANSCO_DC	DCGROUP1	1	24	-1	1	1	2	0.00	1.00	0.02	-2.00
Edit Delete VSC3	Area1	Zone1	TRANSCO_DC	DCGROUP2	2	47	-1	1	1	2	0.00	0.00	0.02	-2.00
Edit Delete VSC4	Area1	Zone1	TRANSCO_DC	DCGROUP2	1	63	-1	1	1	1	0.00	1.00	0.02	-2.00
Edit Delete VSC5	Area1	Zone1	TRANSCO_DC	DCGROUP3	2	49	-1	1	1	2	0.00	0.00	0.02	-2.00
Edit Delete VSC6	Area1	Zone1	TRANSCO_DC	DCGROUP3	1	69	8	-1	1	1	0.00	1.00	0.02	-2.00
Edit Delete VSC7	Area1	Zone1	TRANSCO_DC	DCGROUP4	2	65	-1	7	1	2	0.00	0.00	0.02	-2.00
Edit Delete VSC8	Area1	Zone1	TRANSCO_DC	DCGROUP4	1	68	8	-1	1	1	0.00	1.00	0.02	-2.00
Edit Delete VSC9	Area1	Zone1	TRANSCO_DC	DCGROUP5	2	18	-1	8	1	2	0.00	0.00	0.02	-1.00
Edit Delete VSC10	Area1	Zone1	TRANSCO_DC	DCGROUP5	1	201	10	-1	1	2	0.00	0.00	0.01	-1.00

The description of individual columns of the VSC table is as follows:

Name	voltage source converter name (string)
Area Name	area name (string)
Zone Name	zone name (string)
Owner Name	owner name (string)
Group Name	group name of HVDC lines (string)
Type	VSC type (integer, 1 or 2; 1: Rectifier; 2: Inverter)
ACBusNo	AC bus number of the VSC connected to (long integer)
DCBusA	DC bus number A of the VSC connected to (long integer)
DCBusB	DC bus number B of the VSC connected to (long integer)
Status	VSC status (integer: 0 or 1)

MODE	VSC control mode (integer, 1: PQ; 2: PV)
SELVL1	VSC set point for control mode 1 (double)
SELVL2	VSC set point for control mode 2 (double)
Reactance	VSC coupling transformer reactance (double, p.u.)
Min Capacity	VSC minimum real power capacity (double, MW)
Max Capacity	VSC maximum real power capacity (double, MW)
Min Capacity	VSC minimum reactive power capacity (double, MVAR)
Max Capacity	VSC maximum reactive power capacity (double, MVAR)
EACMIN	VSC minimum AC voltage (double, p.u., default: 0.95)
EACMAX	VSC maximum AC voltage (double, p.u., default: 1.05)
DC Min Current	VSC minimum DC current limit (double, p.u.)
DC Max Current	VSC maximum DC current limit (double, p.u.)

Go to *Home->Inputs->TRANSCOs Input->HVDC->DC Buses* to view the detailed information on each DC bus of the system. Besides, by selecting the different items in the dropdown list on the top left of the DC bus table, a user can choose to display the DC buses of individual TRANSCOs or all the DC buses. The "Download Data" button allows a user to download the detailed DC bus related data listed in the table. The "Add New Bus" button allows a user to add more DC buses to the current system. The "Edit" and "Delete" buttons in front of each existing DC bus record allow a user to edit or delete the chosen DC bus information. The "Edit" operation allows a user to edit the detailed information of the selected DC bus, while the "Delete" operation will delete the DC bus from the system.

Name	Area Name	Zone Name	Owner Name	Group Name	Bus No	Type	R Ground	Voltage Magnitude (p.u.)	Min Voltage Magnitude (p.u.)	Max Voltage Magnitude (p.u.)
Edit Delete DCBUS1	Area1	Zone1	TRANSCO_DC	DCGROUP1	1	3	0.00	1.00	0.90	1.10
Edit Delete DCBUS2	Area1	Zone1	TRANSCO_DC	DCGROUP2	2	3	0.00	1.00	0.90	1.10
Edit Delete DCBUS3	Area1	Zone1	TRANSCO_DC	DCGROUP2	3	3	0.00	1.00	0.90	1.10
Edit Delete DCBUS4	Area1	Zone1	TRANSCO_DC	DCGROUP2	4	3	0.00	1.00	0.90	1.10
Edit Delete DCBUS5	Area1	Zone1	TRANSCO_DC	DCGROUP3	5	3	0.00	1.00	0.90	1.10
Edit Delete DCBUS6	Area1	Zone1	TRANSCO_DC	DCGROUP3	6	3	0.00	1.00	0.90	1.10
Edit Delete DCBUS7	Area1	Zone1	TRANSCO_DC	DCGROUP4	7	3	0.00	1.00	0.90	1.10
Edit Delete DCBUS8	Area1	Zone1	TRANSCO_DC	DCGROUP4	8	3	0.00	1.00	0.90	1.10
Edit Delete DCBUS9	Area1	Zone1	TRANSCO_DC	DCGROUP5	9	3	0.00	1.00	0.95	1.20
Edit Delete DCBUS10	Area1	Zone1	TRANSCO_DC	DCGROUP5	10	3	0.00	1.00	0.95	1.20

The description of individual columns of the DC bus table is as follows:

Name	DC bus name (string)
Area Name	area name (string)
Zone Name	zone name (string)
Owner Name	owner name (string)
Group Name	group name of HVDC lines (string)
BusNo	DC bus number (long integer)
Type	DC bus type (integer, 3 for swing bus that balances losses in the DC network)
R Ground	resistance to ground (double)
Voltage Magnitude	DC bus voltage magnitude (double, p.u.)
Min Voltage Magnitude	minimum DC bus voltage magnitude (double, p.u.)
Max Voltage Magnitude	maximum DC bus voltage magnitude (double, p.u.)

Go to *Home->Inputs->TRANSCOs Input->HVDC->DC Branches* to view the detailed information on each DC branch of the system. Besides, by selecting the different items in the dropdown list on the top left of the DC branch table, a user can choose to display the DC branches of individual TRANSCOs or all the DC branches. The "Download Data" button allows a user to download the detailed DC branch related data listed in the table. The "Add New Branch" button allows a user to add more DC branches to the current system. The "Edit" and "Delete" buttons in front of each existing DC branch record allow a user to edit or delete the chosen DC branch information. The "Edit" operation allows a user to edit the detailed information of the selected DC branch, while the "Delete" operation will delete the DC branch from the system.

	NAME	Area Name	Zone Name	Owner Name	Group Name	IDC	JDC	Circuit ID	Status	Resistance (R)	Rate A (\$/VA)	Rate B (\$/VA)	Rate C (\$/VA)
Edit Delete	DCBRANCH1	Area1	Zone1	TRANSCO_DC	DCGROUP1	1	2	1	1	0.05	1,000.00	1,000.00	1,800.00
Edit Delete	DCBRANCH2	Area1	Zone1	TRANSCO_DC	DCGROUP2	3	4	1	1	0.05	1,000.00	1,000.00	1,800.00
Edit Delete	DCBRANCH3	Area1	Zone1	TRANSCO_DC	DCGROUP3	5	6	1	1	0.05	1,000.00	1,000.00	1,800.00
Edit Delete	DCBRANCH4	Area1	Zone1	TRANSCO_DC	DCGROUP4	7	8	1	1	0.05	1,000.00	1,000.00	1,800.00
Edit Delete	DCBRANCH5	Area1	Zone1	TRANSCO_DC	DCGROUP5	9	10	1	1	0.01	1,000.00	1,000.00	1,800.00
Edit Delete	DCBRANCH6	Area1	Zone1	TRANSCO_DC	DCGROUP6	13	11	1	1	0.00	1,000.00	1,000.00	1,800.00
Edit Delete	DCBRANCH7	Area1	Zone1	TRANSCO_DC	DCGROUP7	11	12	1	1	0.00	1,000.00	1,000.00	1,800.00
Edit Delete	DCBRANCH8	Area1	Zone1	TRANSCO_DC	DCGROUP8	11	13	1	1	0.00	1,000.00	1,000.00	1,800.00
Edit Delete	DCBRANCH9	Area1	Zone1	TRANSCO_DC	DCGROUP9	13	14	1	1	0.00	1,000.00	1,000.00	1,800.00
Edit Delete	DCBRANCH10	Area1	Zone1	TRANSCO_DC	DCGROUP10	13	15	1	1	0.01	1,000.00	1,000.00	1,800.00

The description of individual columns of the DC branch table is as follows:

Name	DC branch name (string)
Area Name	area name (string)
Zone Name	zone name (string)
Owner Name	owner name (string)
Group Name	group name of HVDC lines (string)
IDC	from DC bus number (long integer)
JDC	to DC bus number (long integer)
Circuit ID	circuit ID (character, maximum length 2)
Status	DC branch status (integer: 0 or 1)
Resistance (R)	DC branch resistance (double)

Rate A	flow limit A for long term rating (default: 0; MVA) (double)
Rate B	flow limit B for short term rating (default: 0; MVA) (double)
Rate C	flow limit C for emergency rating (default: 0; MVA) (double)

3.4.4 Inputs – DISCOs Input

Go to *Home->Inputs ->DISCOs Input* to view the overall information of the DISCOs.

This page displays the list of DISCOs, and the statistic information about the numbers of loads that belong to each DISCO. The "Download Data" button allows a user to download the DISCOs related data listed in the table.

The screenshot shows the WINS web application interface. The browser address bar indicates the URL is `http://216.47.134.23/WINS/DISCOs.aspx`. The page title is "Home > Inputs > DISCOs Input". The WINS logo is visible in the top left. A navigation menu on the left lists various input categories under "Inputs", including "Area and Owner", "GENCOs Input", "TRANSDs Input", and "HVDC". The main content area shows a table of DISCOs with columns "Owner" and "Number of Load". A "Download Data" button is located above the table. The table lists six DISCOs: DISCO01, DISCO02, DISCO03, DISCO04, DISCO05, and DISCO06, with their respective number of loads.

Owner	Number of Load
DISCO01	20
DISCO02	20
DISCO03	20
DISCO04	23
DISCO05	6
DISCO06	6

Go to *Home->Inputs ->DISCOs Input->Load Distribution* to view the detailed information on each load of the system. Besides, by selecting the different items in the dropdown list on the top left of the loads table, a user can choose to display the loads of individual DISCOs or all the loads. The "Download Data" button allows a user to download the detailed load related data listed in the table. The "Add New Load" button allows a user to add more loads to the current system. The "Edit" and "Delete" buttons in front of each existing load record allow a user to edit or delete the chosen load information. The "Edit" operation allows a user to edit the detailed information of the selected load, while the "Delete" operation will delete the load from the system.

Name	Area Name	Zone Name	Owner Name	ID	Bus No	Status	PL (MW)	PL%	QL (MVAR)	QL%
Load1	Area1	Zone1	DISTC01	1	1	1	54.34	1.45	9.66	0.60
Load2	Area5	Zone1	DISTC01	1	2	1	23.23	0.57	9.55	0.66
Load3	Area1	Zone1	DISTC01	1	3	1	41.40	1.11	10.61	0.74
Load4	Area1	Zone1	DISTC01	1	4	1	31.85	0.85	12.74	0.88
Load5	Area1	Zone1	DISTC01	1	6	1	95.20	1.49	23.35	1.62
Load6	Area1	Zone1	DISTC01	1	7	1	28.17	0.54	2.12	0.15
Load7	Area1	Zone1	DISTC01	1	11	1	74.21	1.99	24.42	1.69
Load8	Area1	Zone1	DISTC01	1	12	1	49.89	1.34	10.62	0.74
Load9	Area1	Zone1	DISTC01	1	13	1	36.09	0.97	16.99	1.18
Load10	Area1	Zone1	DISTC01	1	14	1	14.86	0.40	1.58	0.07

The description of individual columns of the load table is as follows:

Name	load name (character, maximum length 20, no space)
Area Name	area name (string)
Zone Name	zone name (string)
Owner Name	owner name (string)
ID	load ID (character, maximum length 2)
Bus No	bus number (long integer)
Status	status (integer: 0 or 1)
PL	constant power MW load (default: 0; MW) (double)
PL%	percentage of PL over total load (double)
QL	constant power MVAR load (default: 0; MVAR) (double)
QL%	percentage of QL over total load (double)

3.4.5 Inputs – System Limits

Go to *Home->Inputs ->System Limits* to view limits on system load, system loss, and system reserve. A user can set the values for each system limit or define the simple linear relationship between each individual system limits using the functions on the right of the system limit table.

A user can also directly change hourly load, loss, spinning reserve, and operating reserve in the corresponding tables by clicking the "Select" button in front of each system limit. For example, the following page shows the 24 hours load limit by clicking the "Select" button in front of "Load". "Edit" button in front of each hourly load limit allow a user to edit the chosen load limit.

3.5 Execute SCUC

Go to *Home->Inputs ->Run SCUC* to view all the control parameters used to execute the SCUC program. "Edit" button in front of each parameter allows a user to change the value of the chosen parameter. Click the "Run SCUC" button to execute SCUC. And the whole process is divided into three sub-processes.

- 1) "SCUC.exe" retrieves the input data from oracle database.
- 2) "SCUC.exe" executes the SCUC core algorithm and calculates the optimization results.
- 3) "SCUC.exe" writes the results back to the oracle database.

The screenshot shows the WINS web application interface. The main content area displays the 'Run SCUC' page for the IEEE118WithWind_AC system. The page includes a sidebar with navigation links and a table of SCUC parameters.

Parameter	Value	Description
LMSTEP	1.2E	Lagrange multipliers update step
EDRAMP	1	consider ramping constraint in economic dispatch or not
ECRESERVE	1	consider reserve constraint in economic dispatch or not
INIPW	1	consider initial MW value in UC and ED or not
MAXSDG	0.0020	relative duality gap limit
MAXUCITER	100	maximum UC iteration number
MAXUCITERCUT	10	maximum cut iteration number in the UC phase
MAXEDITERCUT	10	maximum cut iteration number in the ED phase
MCSTRDA	2	network constraint (0: no network constraint; 1: DC; 2: AC)
HVABASE	100	MVA base value

Below the table, there is a message: "It may take several minutes to run SCUC. Do not refresh your internet browser. Please wait..." and a "Run SCUC" button.

3.6 Outputs

Through the TreeView, under "Outputs" node, a user can view and download result of all modules of WINS.

- GENCOs, TRANSCO's Output: output results related to market participants (GENCOs and TRANSCO's)
- LMP: hourly locational marginal prices

3.6.1 Outputs – GENCOs Output

Go to *Home -> Outputs -> GENCOs Output -> Unit Commitment* to view the detailed hourly commitment status of each unit of the system. Besides, by selecting the different items in the dropdown list on the top left of the unit commitment table, a user can choose to display the unit commitment results of individual GENCOs or all GENCOs. The "Download Data" button allows a user to download the detailed unit commitment results listed in the table.

WINS

IEEE118WithWind_AC

Home > Outputs > GENCOs Output > Unit Commitment

All GENCOs Download Data

Unit Index	Unit Name	Unit Type	H1	H2	H3	H4	H5	H6	H7	H8	H9	H10	H11	H12	H13	H14	H15	H16	H17	H18	H19	H20	H21	H22	H23	H24	OWNER
1001	TG01	T	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3
1002	TG02	T	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3
1003	TG03	T	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3
1004	TG04	T	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	3
1005	TG05	T	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	3
1006	TG06	T	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3
1007	TG07	T	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	3
1008	TG08	T	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3
1009	TG09	T	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3
1010	TG10	T	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	3

Go to *Home -> Outputs -> GENCOs Output -> Generation Dispatch* to view the detailed hourly generation dispatch of each unit of the system. Besides, by selecting the different items in the dropdown list on the top left of the unit generation dispatch table, a user can choose to display the unit generation dispatch results of individual GENCOs or all GENCOs. The "Download Data" button allows a user to download the detailed unit generation dispatch results listed in the table.

The screenshot shows the WINS web application interface. The breadcrumb navigation is: Home > Outputs > GENCOs Output > Generation Dispatch. The page title is 'IEEE118WithWind_AC'. The left sidebar shows a tree view of the application structure, with 'Outputs' > 'GENCOs Output' > 'Unit Commitment' selected. The main content area displays a table of hourly generation dispatch data. The table has columns for Unit Index, Unit Name, Unit Type, and 24 hourly dispatch values (H1 to H24). The data is for units TGL1 through TGL10. A dropdown menu on the left of the table allows selecting 'All GENCOs' or individual units. A 'Download Data' button is located above the table.

Unit Index	Unit Name	Unit Type	H1	H2	H3	H4	H5	H6	H7	H8	H9	H10	H11	H12	H13	H14	H15	H16	H17	H18	H19	H20	H21	H22	H23	
1001	TGL1	T	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
1002	TGL2	T	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
1003	TGL3	T	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
1004	TGL4	T	240	180	150	150	150	150	240	270	270	300	300	294.62	270	270	300	300	300	310	300	300	300	300	300	300
1005	TGL5	T	255.09	180	179.99	180	180	140	220	260	260	300	300	300	300	260	300	300	300	300	300	300	300	300	300	300
1006	TGL6	T	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
1007	TGL7	T	0	0	0	0	0	0	30.02	40	35	62.89	55	55	30.43	70	65	55	80	100	100	100	100	100	100	85
1008	TGL8	T	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
1009	TGL9	T	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
1010	TGL10	T	140	180	180	180	180	170.99	220	280	280	280	260	260	260	260	300	300	300	300	300	300	300	300	300	300

Go to *Home->Outputs -> GENCOs Output->Spinning Reserve* to view the detailed hourly spinning reserve of each unit of the system. Besides, by selecting the different items in the dropdown list on the top left of the spinning reserve table, a user can choose to display the unit spinning reserve results of individual GENCOs or all GENCOs. The "Download Data" button allows a user to download the detailed unit spinning reserve results listed in the table.

The screenshot displays the WINS web application interface. The breadcrumb trail at the top reads: *Home > Outputs > GENCOs Output > Spinning Reserve*. The left navigation menu shows the following structure:

- Home
 - Inputs
 - Area and Owner
 - GENCOs Input
 - Fossil Units
 - Combined Cycle Units
 - Hydro Units
 - Catchments
 - Pumped Storage Units
 - Wind Units
 - TRANSEDS Input
 - Buses
 - Branches
 - Transformers
 - Shunt Elements
 - HVDC
 - DISCOs Input
 - Load Distribution
 - 24 Hours Loads
 - System Limits
 - Run SCUC
 - Outputs
 - GENCOs Output
 - Unit Commitment

The main content area shows a table titled "All GENCOs" with a "Download Data" button. The table has the following columns: Unit Index, Unit Name, Unit Type, and 24 columns for hourly spinning reserve (H1 to H24), followed by an "OWNERSHIP" column. The data is as follows:

Unit Index	Unit Name	Unit Type	H1	H2	H3	H4	H5	H6	H7	H8	H9	H10	H11	H12	H13	H14	H15	H16	H17	H18	H19	H20	H21	H22	H23	H24	OWNERSHIP	
1001	TG1	T	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3	
1002	TG2	T	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3	
1003	TG3	T	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	
1004	TG4	T	0	30	30	30	30	30	0	0	0	0	0	5.27	0	0	0	0	0	0	0	0	0	0	0	0	0	1
1005	TG5	T	0	30	30	30	30	30	0	0	0	0	0	0	0	30	0	0	0	0	0	0	0	0	0	0	0	3
1006	TG6	T	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2	
1007	TG7	T	0	0	0	0	0	0	0	30	10	10	10	10	10	10	10	10	10	10	0	0	0	0	10	10	1	
1008	TG8	T	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	
1009	TG9	T	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	
1010	TG10	T	0	30	30	30	30	30	0	30	30	30	30	30	30	0	0	0	0	0	0	0	0	0	0	0	0	2

Go to *Home -> Outputs -> GENCOs Output -> Committed Capacity* to view the detailed hourly committed capacity of each unit of the system. When one unit is scheduled ON in the current hour, its committed capacity is equal to its generation capacity in the current hour; otherwise, its committed capacity is equal to zero in the current hour. Besides, by selecting the different items in the dropdown list on the top left of the committed capacity table, a user can choose to display the unit committed capacity results of individual GENCOs or all GENCOs. The "Download Data" button allows a user to download the detailed unit committed capacity results listed in the table.

Home > Outputs > GENCOs Output > Committed Capacity - Mozilla Firefox

File Edit View History Bookmarks Tools Help

http://216.47.134.239/WINS/UnitsCommittedCapacity.aspx

Home > Outputs > GENCOs Output > C...

WINS

Home > Outputs > GENCOs Output > Committed Capacity

Home > Outputs > GENCOs Output > Committed Capacity

Download Data

Unit Index	Unit Name	Unit Type	H1	H2	H3	H4	H5	H6	H7	H8	H9	H10	H11	H12	H13	H14	H15	H16	H17	H18	H19	H20	H21	H22	H23	H24	DWSER	
1001	TG1	T	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3	
1002	TG2	T	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3	
1003	TG3	T	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3	
1004	TG4	T	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	1
1005	TG5	T	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	3
1006	TG6	T	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2	
1007	TG7	T	0	0	0	0	0	0	0	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	1
1008	TG8	T	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	5	
1009	TG9	T	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	
1010	TG10	T	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	2

1 2 3 4 5 6 7 8

3.6.2 Outputs – TRANSCOs Output

Go to *Home -> Outputs -> TRANSCOs Output -> Branch Flows* to view the detailed hourly flow of each branch of the system. Besides, by selecting the different items in the dropdown list on the top left of the branch flow table, a user can choose to display the branch flow results of individual TRANSCOs or all TRANSCOs. The "Download Data" button allows a user to download the detailed branch flow results listed in the table.

WINS

IEEE118WithWind_AC

Home > Outputs > TRANSCOs Output > Branch Flows

All TransCos Download Data

Name	From Bus	To Bus	Circuit ID	Rate A (MVA)	H1	H2	H3	H4	H5	H6	H7	H8	H9	H10	H11	H12	H13	H14
BR1	1	2	1	175	-26.45	-24.95	-21.94	-24.29	-17.55	-21.72	-27.43	-31.49	-33.06	-36.13	-36.41	-34.88	-33.80	-30.78
BR2	1	3	1	175	-45.65	-44.82	-38.45	-28.05	-35.35	-41.79	-46.67	-51.08	-53.74	-57.82	-57.61	-54.04	-50.88	-49.67
BR3	4	5	1	300	-93.24	-93.32	-78.61	-59.88	-75.16	-89.26	-96.61	-104.05	-109.34	-115.03	-116.85	-108.77	-101.53	-101.58
BR4	3	5	1	175	-74.64	-74.18	-63.33	-47.13	-59.62	-70.08	-77.07	-82.73	-88.18	-93.06	-94.42	-87.93	-82.44	-81.43
BR5	5	6	1	175	88.64	84.01	69.79	54.27	69.48	80.33	88.68	91.27	96.46	100.36	102.04	94.34	87.38	88.83
BR6	6	7	1	175	4.33	11.99	6.60	15.72	14.89	14.81	9.31	6.12	6.74	4.07	4.68	2.51	-0.03	5.79
BR7	8	9	1	300	-337.37	-178.48	-148.75	-148.64	-148.65	-148.75	-237.03	-264.71	-266.43	-295.61	-295.66	-290.43	-266.48	-266.38
BR8	8	5	1	300	311.34	317.69	265.07	204.27	259.57	301.75	326.07	349.26	367.83	385.69	391.94	363.34	327.54	340.63
BR9	9	10	1	300	-238.69	-179.25	-149.27	-149.19	-149.19	-238.39	-268.39	-269.21	-297.99	-297.95	-292.59	-268.18	-268.17	-2
BR10	4	11	1	175	49.64	52.41	42.51	34.96	44.02	50.89	53.01	55.47	58.17	60.27	61.42	56.45	51.76	54.25

Go to *Home -> Outputs -> TRANSCOs Output -> Phase Shifter* to view the detailed hourly phase shift of phase shifter of the system. Besides, by selecting the different items in the dropdown list on the top left of the phase shifter table, a user can choose to display the phase shift results of individual TARNSCOs or all TRANSCOs. The "Download Data" button allows a user to download the detailed phase shift results listed in the table.

The screenshot shows the WINS web application interface. The breadcrumb navigation is *Home > Outputs > TRANSCOs Output > Phase Shifter*. A dropdown menu is set to "All TransCos". A "Download Data" button is visible. The table below shows the phase shift results for TransCo TP9.

NAME	From Bus (1)	To Bus (2)	Circuit ID	H1	H2	H3	H4	H5	H6	H7	H8	H9	H10	H11	H12	H13	H14	H15	H16	H17	H18	H19	H20	H21	H22	H23
TP9	H1	H2	1	-1.39	2.75	1.98	-5.80	-12.67	-5.17	8.32	9.49	9.32	9	6.37	6.58	14	4.83	6	9	9.56	9.50	8	2.86	2.87	8	-10.6

Go to *Home -> Outputs -> TRANSCOs Output -> Tap Changer* to view the detailed hourly turn ratios of transformers of the system. Besides, by selecting the different items in the dropdown list on the top left of the tap changer table, a user can choose to display the tap changer results of individual TRANSCOs or all TRANSCOs. The "Download Data" button allows a user to download the detailed tap changer results listed in the table.

Go to *Home -> Outputs -> TRANSCOs Output -> Bus Voltage Magnitude* to view the detailed hourly voltage magnitudes of buses of the system. Besides, by selecting the different items in the dropdown list on the top left of the bus voltage magnitude table, a user can choose to display the bus voltage magnitude results of individual TRANSCOs or all TRANSCOs. The "Download Data" button allows a user to download the detailed bus voltage magnitude results listed in the table.

The screenshot shows the WINS web application interface. The top navigation bar includes 'Home', 'Outputs', 'TRANSCOs Output', and 'Bus Voltage Magnitude'. The left sidebar contains a navigation menu with categories like 'Inputs', 'TRANSCOs Input', 'DISCOs Input', and 'Outputs'. The main content area displays a table titled 'IEEE118WithWind_AC' with the subtitle 'Home > Outputs > TRANSCOs Output > Bus Voltage Magnitude'. The table has a dropdown menu set to 'All TransCos' and a 'Download Data' button. The table columns are: BUSTO, NAME, LOWVOLTAGE, UPFLTLIMIT, and 12 columns for voltage magnitudes (V1 to V12). The rows represent different buses (BUS1 to BUS10).

BUSTO	NAME	LOWVOLTAGE	UPFLTLIMIT	V1	V2	V3	V4	V5	V6	V7	V8	V9	V10	V11	V12	V13
1	BUS1	0.94	1.05	1.0134	1.0114	0.9828	0.9682	0.9618	1.0095	0.9563	1.0031	0.94	0.9401	0.9404	0.94	0.9422
2	BUS2	0.95	1.06	1.0252	1.0218	0.9934	0.9746	0.9705	1.0183	0.9497	1.0171	0.9558	0.9564	0.9567	0.9564	0.9583
3	BUS3	0.95	1.06	1.0223	1.0201	0.99	0.9734	0.9684	1.0176	0.9655	1.0130	0.9512	0.9525	0.9531	0.9514	0.9529
4	BUS4	0.99	1.09	1.0325	1.0498	1.0129	0.99	0.99	1.0451	0.9867	1.0468	0.9910	0.9973	0.9991	0.9919	0.99
5	BUS5	0.99	1.09	1.0361	1.0133	1.0156	0.9919	0.9924	1.0485	1.0002	1.0506	0.9853	1.0022	1.0041	0.9963	0.9940
6	BUS6	0.97	1.09	1.0363	1.0331	1.0011	0.9803	0.9779	1.0291	0.9806	1.0292	0.9705	0.9739	0.9748	0.9713	0.9714
7	BUS7	0.97	1.09	1.0305	1.0347	1.0004	0.9817	0.9799	1.0392	0.9836	1.0321	0.9795	0.9763	0.9771	0.9745	0.9749
8	BUS8	0.98	1.09	1.0424	1.0596	1.0198	0.9996	1.0008	1.0540	1.0060	1.0583	1.0093	1.0223	1.0257	1.0509	1.0052
9	BUS9	0.98	1.09	1.09	1.09	1.0393	1.0595	1.0310	1.09	1.0204	1.09	1.0367	1.0687	1.0705	1.0421	1.0300
10	BUS10	0.98	1.09	1.0818	1.0625	1.0221	0.9835	0.9851	1.0877	1.0020	1.0870	1.0322	1.0837	1.0837	1.0425	1.0250

Go to *Home -> Outputs -> TRANSCOs Output -> Bus Voltage Angle* to view the detailed hourly voltage angles of buses of the system. Besides, by selecting the different items in the dropdown list on the top left of the bus voltage angle table, a user can choose to display the bus voltage angle results of individual TRANSCOs or all TRANSCOs. The "Download Data" button allows a user to download the detailed bus voltage angle results listed in the table.

The screenshot displays the WINS web application interface. The breadcrumb trail at the top reads: *Home > Outputs > TRANSCOs Output > Bus Voltage Angle*. The left sidebar contains a navigation menu with the following items:

- Home
 - Inputs
 - Area and Owner
 - GENCOs Input
 - Fossil Units
 - Combined Cycle Units
 - Hydro Units
 - Catchments
 - Pumped Storage Units
 - Wind Units
 - TRANSCOs Input
 - Buses
 - Branches
 - Transformers
 - Shunt Elements
 - HVDC
 - DISCOs Input
 - Load Distribution
 - 24 Hour Loads
 - System Limits
 - Run SCUC
 - Outputs
 - GENCOs Output
 - Unit Commitment

The main content area shows the IEEE118WithWind_AC bus voltage angle table. The table has a dropdown menu set to "All TRANSCOs" and a "Download Data" button. The table columns are: Bus No, Name, H1, H2, H3, H4, H5, H6, H7, H8, H9, H10, H11, H12, H13, H14, H15, H16, H17, H18, H19, H20. The table contains 10 rows of data for buses BUS1 through BUS10, showing voltage angles for each of the 24 hours.

Bus No	Name	H1	H2	H3	H4	H5	H6	H7	H8	H9	H10	H11	H12	H13	H14	H15	H16	H17	H18	H19	H20
1	BUS1	-29.65	-35.98	-29.29	-15.44	-28.15	-37.87	-31.86	-29.25	-32.97	-35.28	-36.84	-32.01	-30.57	-31.64	-34.99	-34.78	-32.91	-34.74	-39.58	-42.1
2	BUS2	-29.13	-34.81	-28.03	-15.61	-27.13	-36.68	-30.24	-27.55	-30.98	-33.03	-34.39	-29.87	-28.58	-29.78	-32.76	-32.43	-30.75	-32.48	-37.23	-40.1
3	BUS3	-29.63	-34.84	-28.37	-15.74	-27.28	-36.92	-30.68	-28.00	-31.58	-33.79	-35.16	-30.81	-29.23	-30.38	-33.82	-33.28	-31.48	-33.29	-39.01	-41.1
4	BUS4	-24.87	-31.15	-24.90	-13.06	-21.85	-32.35	-28.31	-23.79	-28.51	-29.81	-25.56	-24.51	-25.67	-26.24	-27.81	-26.38	-27.92	-32.39	-35.1	
5	BUS5	-24.51	-30.79	-24.57	-12.79	-23.51	-32.88	-25.89	-23.35	-28.03	-26.02	-29.32	-25.09	-24.07	-25.23	-27.75	-27.38	-25.98	-27.42	-31.67	-34.1
6	BUS6	-26.68	-33.04	-26.60	-14.45	-25.64	-33.17	-28.46	-25.84	-28.93	-30.97	-32.31	-27.91	-26.69	-27.92	-30.78	-30.38	-28.76	-30.40	-35.01	-38.1
7	BUS7	-26.73	-33.20	-26.72	-14.60	-25.86	-33.36	-28.62	-25.95	-29.06	-31.09	-32.40	-27.99	-26.74	-28.04	-30.79	-30.47	-28.94	-30.48	-35.11	-38.1
8	BUS8	-25.33	-36.88	-25.71	-9.89	-19.59	-28.88	-21.00	-18.64	-28.50	-22.33	-23.58	-19.44	-18.97	-20.07	-22.06	-21.58	-20.37	-21.78	-25.88	-28.1
9	BUS9	-14.83	-23.80	-18.32	-7.14	-17.06	-26.75	-16.99	-14.69	-16.13	-17.78	-19.01	-14.91	-14.58	-15.61	-17.63	-16.88	-15.68	-17.09	-21.37	-23.1
10	BUS10	-13.62	-21.04	-15.63	-6.22	-14.14	-24.40	-12.56	-10.44	-11.43	-13.03	-14.29	-9.89	-9.78	-10.01	-12.60	-11.92	-10.66	-12.35	-16.69	-19.1

Go to *Home -> Outputs -> TRANSCOs Output -> HVDC -> CSC AC Terminal MW* to view the detailed hourly terminal AC real power dispatch of the current source converters of the system. Besides, by selecting the different items in the dropdown list on the top left of the CSC AC terminal MW table, a user can choose to display the CSC terminal AC real power dispatch results of individual TRANSCOs or all TRANSCOs. The "Download Data" button allows a user to download the detailed CSC terminal AC real power dispatch results listed in the table.

The screenshot shows the WINS web application interface. The breadcrumb navigation path is: Home > Outputs > TRANSCOs Output > HVDC > CSC AC Terminal MW. The table displays real power dispatch results for two converter stations, COVT1 and COVT2, across 20 buses (B1 to B20). The table has a dropdown menu set to 'All TransCos' and a 'Download Data' button.

name	B1	B2	B3	B4	B5	B6	B7	B8	B9	B10	B11	B12	B13	B14	B15	B16	B17	B18	B19	B20
COVT1	5.16	103.38	32.93	0.00	87.97	127.70	42.43	77.51	25.34	72.23	36.70	15.05	78.87	41.80	96.84	32.15	98.70	83.25	58.11	284.11
COVT2	-5.16	-102.81	-32.87	0.00	-86.99	-128.92	-42.34	-77.23	-25.10	-71.94	-36.64	-15.04	-79.57	-41.71	-96.45	-32.10	-99.26	-85.92	-87.98	-282.47

Go to *Home -> Outputs -> TRANSCOs Output -> HVDC -> CSC AC Terminal MVAR* to view the detailed hourly terminal AC reactive power dispatch of the current source converters of the system. Besides, by selecting the different items in the dropdown list on the top left of the CSC AC terminal MVAR table, a user can choose to display the CSC terminal AC reactive power dispatch results of individual TARNSCOs or all TRANSCOs. The "Download Data" button allows a user to download the detailed CSC terminal AC reactive power dispatch results listed in the table.

The screenshot shows the WINS web application interface. The breadcrumb trail at the top reads: *Home > Outputs > TRANSCOs Output > HVDC > CSC AC Dispatch (MVar)*. The left navigation menu includes: *Home*, *Inputs*, *Run SCUC*, *Outputs*, *TRANSCOs Output*, *Branch Flows*, *Phase Shifter*, *Tap Changer*, *Bus Voltage Magnitude*, *Bus Voltage Angle*, *HVDC*, *CSC AC Angle*, *CSC Angle*, *CSC Voltage*, *CSC AC Dispatch (MW)*, and *CSC AC Dispatch (MVar)*. The main content area displays a table titled "IEEE118WithWindHVDC_AC" showing the CSC AC Dispatch (MVar) for two converters, COVT1 and COVT2, across 24 buses (B1 to B24). The table has a dropdown menu set to "All TransCos" and a "Download Data" button.

name	B1	B2	B3	B4	B5	B6	B7	B8	B9	B10	B11	B12	B13	B14	B15	B16	B17	B18	B19	B20	B21	B22	B23	B24
COVT1	0.24	6.72	12.87	2.40	0.00	9.24	14.45	21.78	14.32	15.18	0.00	24.45	29.24	17.70	32.76	14.25	30.83	16.11	23.69	23.55	21.18	21.61	9.48	8.19
COVT2	0.08	0.00	9.90	2.26	0.00	7.26	12.72	11.17	9.87	2.89	0.00	10.52	11.19	18.58	10.98	0.92	7.74	0.00	8.86	13.61	25.45	4.86	1.95	5.18

Go to *Home -> Outputs -> TRANSCOs Output -> HVDC -> CSC AC Angle* to view the detailed hourly AC angles of the current source converters of the system. Besides, by selecting the different items in the dropdown list on the top left of the CSC AC angle table, a user can choose to display the CSC AC angle results of individual TRANSCOs or all TRANSCOs. The "Download Data" button allows a user to download the detailed CSC AC angle results listed in the table.

The screenshot shows the WINS web application interface. The breadcrumb navigation path is: Home > Outputs > TRANSCOs Output > HVDC > CSC AC Angle. The left sidebar contains a tree view with categories: Home, Inputs (Area and Owner, GENCOs Input, TRANSCOs Input, DISCOs Input, System Limits), Run SCUC, and Outputs (GENCOs Output, TRANSCOs Output, Branch Flows, Phase Shifter, Tap Changer, Bus Voltage Magnitude, Bus Voltage Angle, HVDC (CSC AC Terminal PW, CSC AC Terminal HVAR, CSC AC Angle)). The main content area displays a table of CSC AC angles for two converters, C0VT1 and C0VT2, across 22 buses (H1 to H22). A dropdown menu is set to 'All TransCos' and a 'Download Data' button is present.

Name	H1	H2	H3	H4	H5	H6	H7	H8	H9	H10	H11	H12	H13	H14	H15	H16	H17	H18	H19	H20	H21	H22
C0VT1	14.68	3.34	3.34	1.07	11.39	9.83	21.88	17.11	19.74	19.77	9.98	14.78	19.98	21.26	10.48	18.88	18.28	15.62	0.00	8.69	28.66	17.60
C0VT2	-12.22	-7.17	-4.64	-13.76	-8.88	-9.86	-25.98	-12.65	-2.31	-6.29	0.00	0.00	-6.24	-12.49	-2.32	0.00	-6.92	-3.48	0.00	-4.41	-14.57	-4.62

Go to *Home -> Outputs -> TRANSCOs Output -> HVDC -> CSC DC Voltage* to view the detailed hourly voltages of the current source converters of the system. Besides, by selecting the different items in the dropdown list on the top left of the CSC DC voltage table, a user can choose to display the CSC DC voltage results of individual TRANSCOs or all TRANSCOs. The "Download Data" button allows a user to download the detailed CSC DC voltage results listed in the table.

The screenshot shows the WINS web application interface. The browser address bar displays the URL: `http://216.47.134.239/WINS/vCscVoltage.aspx`. The page title is "IEEE118WithWindHVDC_AC". The navigation menu on the left includes "Home", "Inputs", "Outputs", and "HVDC". The "Outputs" section is expanded, showing "TRANSCOs Output" and "CSC DC Voltage". The "CSC DC Voltage" table is displayed, showing the detailed hourly voltages of the current source converters of the system. The table has a dropdown menu for "All TransCos" and a "Download Data" button. The table data is as follows:

Name	H1	H2	H3	H4	H5	H6	H7	H8	H9	H10	H11	H12	H13	H14	H15	H16	H17	H18	H19
COVT1	0.9508	0.9509	0.9508	0.9508	0.9513	1.0177	0.9879	1.0372	0.9644	0.9598	1.0536	1.0086	1.0376	0.9789	1.0953	1.0346	0.9618	0.9978	1.1013
COVT2	0.9503	0.9507	0.9481	0.9500	0.9467	1.0114	0.9850	1.0335	0.9531	0.9557	1.0519	0.9988	1.0337	0.9687	1.0930	1.0333	0.9566	0.9937	1.0967

Go to *Home* -> *Outputs* -> *TRANSCOs Output* -> *HVDC* -> *CSC DC Current* to view the detailed hourly current of the current source converters of the system. Besides, by selecting the different items in the dropdown list on the top left of the CSC DC current table, a user can choose to display the CSC DC current results of individual TRANSCOs or all TRANSCOs. The "Download Data" button allows a user to download the detailed CSC DC current results listed in the table.

The screenshot shows the WINS web application interface. The browser address bar displays the URL: `http://216.47.134.23/WINS/CscCurrent.aspx`. The page title is "IEEE118WithWindHVDC_AC". The navigation menu on the left includes: Home, Inputs (Area and Owner, GENCOs Input, TRANSCOs Input, DISCOs Input, System Limits), Run SCUC, and Outputs (GENCOs Output, TRANSCOs Output, Branch Flows, Phase Shifter, Tap Changer, Bus Voltage Magnitude, Bus Voltage Angle, HVDC (CSC AC Terminal MW, CSC AC Terminal MVAR, CSC AC Angle, CSC DC Voltage, CSC DC Current, CSC Firing/Extinction Angle)). The main content area shows the breadcrumb path: Home > Outputs > TRANSCOs Output > HVDC > CSC DC Current. Below the breadcrumb is a dropdown menu set to "All TransCos" and a "Download Data" button. The table displays the CSC DC Current for two converters, COVT1 and COVT2, across 12 time intervals (H1 to H12).

Name	H1	H2	H3	H4	H5	H6	H7	H8	H9	H10	H11	H12	H13	H14	H15	H16	H17
COVT1	0.0543	1.0430	0.3464	0.0000	0.9394	1.2547	0.4295	-0.7473	0.2834	0.7527	-0.3483	0.1304	0.7697	0.4305	0.8841	0.3137	1.0345
COVT2	-0.0543	-1.0430	-0.3464	0.0000	-0.9394	-1.2547	-0.4295	0.7473	-0.2834	-0.7527	0.3483	-0.1304	-0.7697	-0.4305	-0.8841	-0.3137	-1.0345

Go to *Home* -> *Outputs* -> *TRANSCOs Output* -> *HVDC* -> *CSC Firing/Extinction Angle* to view the detailed hourly Firing/Extinction angles of the current source converters of the system. Besides, by selecting the different items in the dropdown list on the top left of the CSC Firing/Extinction angle table, a user can choose to display the CSC DC Firing/Extinction angle results of individual TARNSCOs or all TRANSCOs. The "Download Data" button allows a user to download the detailed CSC Firing/Extinction angle results listed in the table.

The screenshot shows the WINS web application interface. The breadcrumb navigation path is: Home > Outputs > TRANSCOs Output > HVDC > CSC Firing/Extinction Angle. The left sidebar contains a tree view with categories: Home, Inputs (Area and Owner, GENCOs Input, TRANSCOs Input, DISCOs Input, System Limits), Run SCUC, and Outputs (GENCOs Output, TRANSCOs Output, Phase Shifter, Tap Changer, Bus Voltage Magnitude, Bus Voltage Angle, HVDC). Under TRANSCOs Output, the 'CSC Firing/Extinction Angle' option is selected. The main content area displays a table for 'All TransCos' with a 'Download Data' button. The table has columns for 'Name' and 24 hourly values (H1 to H24) for two converters, COVT1 and COVT2.

Name	H1	H2	H3	H4	H5	H6	H7	H8	H9	H10	H11	H12	H13	H14	H15	H16	H17	H18	H19	H20	H21	H22	H23	
COVT1	15.71	5.11	5.31	5.45	12.10	18.45	21.45	17.70	28.41	28.25	11.26	15.75	20.89	21.63	11.34	17.67	18.60	14.22	5.00	9.97	21.28	18.80	20.31	
COVT2	13.44	8.17	8.95	14.09	9.70	18.48	16.70	13.44	5.40	7.71	5.22	5.33	7.72	13.48	5.31	5.28	7.83	5.62	5.00	6.03	13.46	5.98	9.87	

Go to *Home -> Outputs -> TRANSCOs Output -> HVDC -> CSC Transformer Tap* to view the detailed hourly transformer turns ratio of the current source converters of the system. Besides, by selecting the different items in the dropdown list on the top left of the CSC transformer tap table, a user can choose to display the CSC transformer tap results of individual TRANSCOs or all TRANSCOs. The "Download Data" button allows a user to download the detailed CSC transformer tap results listed in the table.

The screenshot shows the WINS web application interface. The breadcrumb navigation path is: Home > Outputs > TRANSCOs Output > HVDC > CSC Transformer Tap. The left sidebar contains a tree view with categories: Home, Inputs (Area and Owner, GENCOs Input, TRANSCOs Input, DSTATs Input, System Limits), Run SCUC, and Outputs (GENCOs Output, TRANSCOs Output, Branch Flows, Phase Shifter, Tap Changer, Bus Voltage Magnitude, Bus Voltage Angle, HVDC (CSC AC Terminal PW, CSC AC Terminal MVAR, CSC AC Angle, CSC DC Voltage, CSC DC Current, CSC Firing/Extinction Angle, CSC Transformer Tap, VSC AC Terminal PW)).

The main content area displays a table titled "CSC Transformer Tap" with a dropdown menu set to "All TransCos" and a "Download Data" button. The table has 20 columns representing different transformer taps (H1 to H20) and two rows of data for C0VT1 and C0VT2.

Name	H1	H2	H3	H4	H5	H6	H7	H8	H9	H10	H11	H12	H13	H14	H15	H16	H17	H18	H19
C0VT1	0.9608	1.0038	0.9964	0.9472	0.9921	0.9928	0.9779	1.0044	0.9394	0.9438	0.9864	0.9542	1.0155	0.9639	1.0249	0.9972	0.9510	0.9574	1.0195
C0VT2	0.9668	1.0293	0.9885	0.9384	0.9885	1.0036	1.0050	1.0948	0.9829	0.9902	1.0028	1.0382	1.0742	1.0270	1.1251	1.0010	0.9937	1.0046	1.1289

Go to *Home -> Outputs -> TRANSCOs Output -> HVDC -> VSC AC Terminal MW* to view the detailed hourly terminal AC real power dispatch of the voltage source converters of the system. Besides, by selecting the different items in the dropdown list on the top left of the VSC terminal AC dispatch (MW) table, a user can choose to display the VSC terminal AC real power dispatch results of individual TRANSCOs or all TRANSCOs. The "Download Data" button allows a user to download the detailed VSC terminal AC real power dispatch results listed in the table.

Home > Outputs > TRANSCOs Output > HVDC > VSC AC Terminal MW - Mozilla Firefox

FileEditViewHistoryBookmarksToolsHelp

http://132.167.134.239/WIND/vscacp.aspx

Home > Outputs > TRANSCOs Output > HVDC > VSC AC Terminal MW

IEEE118WithWindHVDC_AC

Home > Outputs > TRANSCOs Output > HVDC > VSC AC Terminal MW

All TransCosDownload Data

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Name	H1	H2	H3	H4	H5	H6	H7	H8	H9	H10	H11	H12	H13	H14	H15	H16	H17	I	
VSC1	-17.75	-55.98	65.21	34.69	21.74	10.13	42.15	5.12	11.73	-42.74	-25.67	-6.00	5.04	5.72	-23.33	-9.52	3.78	-26.57	-1.1
VSC2	-17.68	-34.81	-61.60	-14.43	-21.60	-18.00	-41.48	-5.11	-11.68	43.45	25.92	6.01	-5.04	-5.71	23.54	9.56	-3.78	26.41	1.1
VSC3	-41.48	-10.68	50.32	158.65	51.38	30.03	17.38	9.94	-6.50	-36.98	-79.22	-107.02	-72.74	-38.10	-46.57	-49.75	-21.24	-28.17	-1.0
VSC4	-42.14	18.71	-49.38	-149.14	-50.31	-37.78	-17.19	-3.85	6.60	37.43	81.75	111.74	74.85	38.66	47.41	50.73	21.41	28.47	1.4
VSC5	-3.45	-23.49	19.81	40.19	74.34	3.75	-2.86	-0.80	-5.74	-42.18	8.34	-34.50	-26.58	-1.11	-58.99	-4.75	-40.00	-97.73	-0.1
VSC6	1.45	23.70	-19.76	-79.49	-72.25	-3.79	2.84	0.98	5.76	42.79	-6.34	35.10	25.77	1.12	68.36	4.75	40.62	103.68	0.1
VSC7	13.88	-9.52	13.53	90.48	12.42	-2.32	15.37	0.33	-7.69	-49.12	-94.40	-23.67	-5.33	1.07	-37.58	-82.66	-42.00	-18.74	-3.1
VSC8	-23.43	8.54	-12.48	-87.38	-32.01	2.32	-15.29	-8.33	7.71	71.04	96.01	23.89	5.34	-1.07	38.08	85.42	42.69	18.87	3.1
VSC9	-70.55	-100.00	-96.47	-71.88	-2.77	-34.28	-96.05	-20.71	-48.85	-100.00	-100.00	-100.00	-100.00	-97.24	-95.44	-100.00	-100.00	-100.00	-0.1
VSC18	48.38	53.13	24.96	13.98	13.08	10.97	50.95	58.73	34.08	89.39	53.85	58.72	49.82	59.54	44.28	58.74	27.57	39.51	3.0

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Go to *Home -> Outputs -> TRANSCOs Output -> HVDC -> VSC AC Terminal MVAR* to view the detailed hourly terminal AC reactive power dispatch of the voltage source converters of the system. Besides, by selecting the different items in the dropdown list on the top left of the VSC terminal AC dispatch (MVar) table, a user can choose to display the VSC terminal AC reactive power dispatch results of individual TRANSCOs or all TRANSCOs. The "Download Data" button allows a user to download the detailed VSC terminal AC reactive power dispatch results listed in the table.

WINS

IEEE118WithWindHVDC_AC

Home > Outputs > TRANSCOs Output > HVDC > VSC AC Terminal MVAR

All TransCos Download Data

Name	H1	H2	H3	H4	H5	H6	H7	H8	H9	H10	H11	H12	H13	H14	H15	H16	H17	H18	H19
VSC1	-67.41	-66.80	-35.99	55.99	34.53	2.67	34.20	29.16	-14.39	-60.82	-67.62	-63.64	13.85	7.50	-24.21	-63.89	-12.96	-33.89	-70.00
VSC2	55.31	15.00	17.54	18.53	-0.94	13.99	2.70	-13.02	53.77	53.24	64.85	64.89	-0.04	-1.48	60.64	62.18	-4.64	63.93	70.00
VSC3	-62.69	23.35	38.89	-1.29	29.48	24.92	68.46	66.05	-66.76	67.47	70.00	67.54	66.55	69.87	65.37	69.50	-65.96	59.69	60.72
VSC4	-66.16	63.61	70.00	63.52	70.00	70.00	70.00	63.86	70.00	58.47	70.00	67.55	48.82	67.49	70.00	69.87	66.15	70.00	
VSC5	-65.84	70.00	33.52	70.00	70.00	67.04	58.64	56.65	-49.78	-69.78	42.82	70.00	44.73	61.90	33.79	-49.50	60.60	65.75	70.00
VSC6	70.00	70.00	70.00	70.00	70.00	70.00	70.00	70.00	70.00	70.00	58.28	70.00	67.45	70.00	70.00	67.66	70.00	56.64	70.00
VSC7	-41.17	14.89	59.52	56.98	62.88	63.29	35.16	-43.52	-63.07	60.37	70.00	66.89	48.43	62.41	69.38	69.48	-54.17	19.41	70.00
VSC8	70.00	70.00	6.85	-14.17	7.95	-49.32	33.10	-3.11	63.26	-50.91	6.43	0.00	-1.81	-18.93	-49.88	70.00	-67.81	-67.78	30.82
VSC9	189.65	180.34	97.69	125.37	137.68	143.69	157.24	206.69	185.49	232.81	254.96	227.81	147.35	166.73	221.76	182.34	192.82	189.09	211.79
VSC10	-50.51	-50.85	-50.34	-50.29	-50.29	-50.29	-50.56	-50.86	-50.40	-50.81	-50.80	-50.66	-50.55	-50.67	-50.49	-50.86	-50.36	-50.45	-50.38

Go to *Home -> Outputs -> TRANSCOs Output -> HVDC -> VSC AC Angle* to view the detailed hourly AC angle of the voltage source converters of the system. Besides, by selecting the different items in the dropdown list on the top left of the VSC AC angle table, a user can choose to display the VSC AC angle results of individual TRANSCOs or all TRANSCOs. The "Download Data" button allows a user to download the detailed VSC AC angle results listed in the table.

WINS

IEEE118WithWindHVDC_AC

Home > Outputs > TRANSCOs Output > HVDC > VSC AC Angle

All TransCos Download Data

Name	H1	H2	H3	H4	H5	H6	H7	H8	H9	H10	H11	H12	H13	H14	H15	H16	H17	H18	H19	H20	H21	H22	H23	H24
VSC1	0.20	0.57	0.69	0.38	0.24	0.19	0.47	0.05	0.12	-0.43	-0.28	-0.06	0.05	0.06	-0.24	-0.09	0.03	-0.27	-0.11	0.47	-0.57	-0.34	-0.53	0
VSC2	-0.17	-0.63	-0.75	-0.17	-0.24	-0.22	-0.48	-0.15	-0.12	0.47	0.29	0.06	-0.05	-0.18	0.25	0.10	-0.18	0.29	0.13	-0.52	0.62	0.37	0.58	0
VSC3	-0.49	-0.11	0.69	1.89	0.60	0.44	0.20	0.04	-0.07	-0.39	-0.60	-1.14	-0.00	-0.43	-0.48	-0.56	-0.22	-0.29	-1.43	-1.05	-1.47	-0.51	-0.20	0
VSC4	0.41	0.10	-0.51	-1.67	-0.57	-0.35	-0.19	-0.04	0.07	0.40	0.87	1.22	0.80	0.42	0.51	0.55	0.23	0.30	1.45	1.78	1.42	0.54	0.20	0
VSC5	-0.03	-0.25	0.21	0.45	0.04	0.04	-0.03	0.00	-0.06	-0.42	0.06	-0.36	-0.27	-0.01	-0.59	-0.05	-0.40	-0.93	-0.69	1.49	-0.34	-0.02	0.00	0
VSC6	0.03	0.23	-0.29	-0.44	-0.82	-0.04	0.03	0.00	0.06	0.48	-0.18	0.38	0.28	0.01	0.65	0.05	0.44	1.39	0.71	1.46	0.71	0.02	0.00	0
VSC7	0.14	-0.10	0.15	1.06	0.38	-0.02	0.12	0.00	-0.08	-0.72	-1.00	-0.25	-0.08	0.01	-0.19	-0.93	-0.45	-0.19	-0.39	-0.69	-2.20	-0.62	1.14	0
VSC8	-0.13	0.10	-0.15	-1.03	-0.37	0.02	-0.17	0.00	0.09	0.81	1.15	0.28	0.06	-0.31	0.43	0.96	0.47	0.21	0.43	0.76	2.19	0.63	1.36	0
VSC9	-0.77	-1.06	-1.15	-0.57	-0.03	-0.40	-1.04	-0.22	-0.54	-1.04	-1.03	-1.06	-1.10	-1.10	-0.58	-1.10	-1.09	-1.04	-0.64	0.01	-0.71	-0.85	-0.94	-1
VSC10	0.29	0.37	0.15	0.08	0.06	0.07	0.32	0.37	0.21	0.44	0.34	0.37	0.31	0.36	0.26	0.37	0.17	0.25	0.19	0.36	0.22	0.29	0.37	0

Go to *Home -> Outputs -> TRANSCOs Output -> HVDC -> VSC DC Voltage* to view the detailed hourly DC voltage of the voltage source converters of the system. Besides, by selecting the different items in the dropdown list on the top left of the VSC DC voltage table, a user can choose to display the VSC DC voltage results of individual TRANSCOs or all TRANSCOs. The "Download Data" button allows a user to download the detailed VSC DC voltage results listed in the table.

The screenshot displays the WINS web application interface. The breadcrumb trail at the top reads: *Home > Outputs > TRANSCOs Output > HVDC > VSC DC Voltage*. The left navigation menu shows the following structure:

- Home
 - Inputs
 - Area and Owner
 - GENCOs Input
 - TRANSCOs Input
 - DISCOs Input
 - System Limits
 - Run SCUC
 - Outputs
 - GENCOs Output
 - TRANSCOs Output
 - Branch Flows
 - Phase Shifter
 - Tap Changer
 - Bus Voltage Magnitude
 - Bus Voltage Angle
 - HVDC
 - CSC AC Terminal MW
 - CSC AC Terminal MVAR
 - CSC AC Angle
 - CSC DC Voltage
 - CSC DC Current
 - CSC Firing/Extinction Angle
 - CSC Transformer Tap
 - VSC AC Terminal MW
 - VSC AC Angle
 - VSC DC Voltage
 - VSC DC Current

The main content area shows a table titled "IEEE118WithWindHVDC_AC". Above the table is a dropdown menu set to "All TransCos" and a "Download Data" button. The table has 19 columns: Name, H1, H2, H3, H4, H5, H6, H7, H8, H9, H10, H11, H12, H13, H14, H15, H16, H17, H18, H19. The data rows are as follows:

Name	H1	H2	H3	H4	H5	H6	H7	H8	H9	H10	H11	H12	H13	H14	H15	H16	H17	H18	H19
VSC1	1.1500	1.1500	1.1500	1.1493	1.1500	1.1499	1.1500	1.1500	1.1500	1.1511	1.1387	1.1473	1.1500	1.1500	1.1397	1.1442	1.1491	1.1397	1.1449
VSC2	1.1422	1.1254	1.1214	1.1429	1.1405	1.1420	1.1316	1.1477	1.1448	1.1500	1.1500	1.1500	1.1479	1.1475	1.1500	1.1483	1.1475	1.1452	1.1500
VSC3	1.1516	1.1453	1.1500	1.1500	1.1500	1.1497	1.1500	1.1500	1.1471	1.1397	1.1344	1.1013	1.1374	1.1301	1.1299	1.1279	1.1406	1.1376	1.0876
VSC4	1.1500	1.1500	1.1281	1.0818	1.1275	1.1330	1.1424	1.1482	1.1500	1.1500	1.1500	1.1499	1.1500	1.1500	1.1500	1.1500	1.1500	1.1500	1.1490
VSC5	1.1484	1.1396	1.1500	1.1497	1.1500	1.1500	1.1487	1.1491	1.1474	1.1313	1.1500	1.1367	1.1383	1.1495	1.1237	1.1479	1.1323	1.1067	1.1205
VSC6	1.1500	1.1500	1.1413	1.1323	1.1376	1.1483	1.1500	1.1496	1.1500	1.1500	1.1472	1.1500	1.1500	1.1500	1.1500	1.1500	1.1500	1.1500	1.1500
VSC7	1.1494	1.1458	1.1500	1.1500	1.1500	1.1489	1.1500	1.1499	1.1466	1.1164	1.1073	1.1396	1.1476	1.1500	1.1311	1.1128	1.1314	1.1417	1.1341
VSC8	1.1429	1.1500	1.1442	1.1206	1.1355	1.1500	1.1433	1.1497	1.1500	1.1473	1.1500	1.1500	1.1500	1.1495	1.1477	1.1500	1.1500	1.1500	1.1500
VSC9	1.1324	1.1922	1.1283	1.1890	1.1979	1.1907	1.1847	1.1987	1.1937	1.1869	1.1889	1.1924	1.1732	1.1453	1.1347	1.1928	1.1871	1.1900	1.1873
VSC13	1.1361	1.1973	1.1908	1.1886	1.1980	1.1924	1.1896	1.1997	1.1961	1.1919	1.1939	1.1874	1.1763	1.1504	1.1377	1.1975	1.1922	1.1950	1.1903

Go to *Home* -> *Outputs* -> *TRANSCOs Output* -> *HVDC* -> *VSC DC Current* to view the detailed hourly DC current of the voltage source converters of the system. Besides, by selecting the different items in the dropdown list on the top left of the VSC DC current table, a user can choose to display the VSC DC current results of individual TRANSCOs or all TRANSCOs. The "Download Data" button allows a user to download the detailed VSC DC current results listed in the table.

The screenshot displays the WINS web application interface. The breadcrumb navigation path is: Home > Outputs > TRANSCOs Output > HVDC > VSC DC Current. The left sidebar shows a tree view of the application's structure, with 'VSC DC Current' selected under the 'HVDC' category. The main content area features a table titled 'All TransCos' with a 'Download Data' button. The table lists 17 rows of data, each representing a different VSC DC current component (VSC1 to VSC17). Each row contains 17 numerical values, likely representing hourly data points. The table is organized into columns labeled H1 through H17. The data values are small, ranging from approximately -0.0000 to 0.0000.

TransCo	H1	H2	H3	H4	H5	H6	H7	H8	H9	H10	H11	H12	H13	H14	H15	H16	H17
VSC1	0.1545	0.4568	0.5670	0.1278	0.1899	0.1576	0.3866	0.0445	0.1020	-0.3779	-0.2294	-0.0523	0.0438	0.0487	-0.2047	-0.0032	0.0322
VSC2	-0.1545	-0.4568	-0.5670	-0.1278	-0.1899	-0.1576	-0.3866	-0.0445	-0.1020	0.3779	0.2294	0.0523	-0.0438	-0.0487	0.2047	0.0032	-0.0322
VSC3	-0.3054	-0.0931	0.4376	1.3796	0.4461	0.3334	0.1504	0.0344	-0.0574	-0.3295	-0.7108	-0.9717	-0.6509	-0.3362	-0.4122	-0.4411	0.1862
VSC4	0.3864	0.0931	-0.4376	-1.3796	-0.4461	-0.3334	-0.1504	-0.0344	0.0574	0.3295	0.7108	0.9717	0.6509	0.3362	0.4122	0.4411	-0.1862
VSC5	-0.0350	-0.2061	0.1711	0.3488	0.6464	0.0350	-0.0248	-0.0079	-0.0200	-0.3721	0.0551	-0.3843	-0.1527	-0.0097	-0.5249	-0.0413	-0.2523
VSC6	0.0350	0.2061	-0.1711	-0.3488	-0.6464	-0.0350	0.0248	0.0079	0.0200	0.3721	-0.0551	0.3843	0.1527	0.0097	0.5249	0.0413	0.2523
VSC7	0.1175	-0.0830	0.1177	0.7867	0.2819	-0.0282	0.1337	0.0028	-0.0670	-0.6191	-0.8824	-0.2877	-0.0464	0.0080	-0.3320	-0.7428	-0.3712
VSC8	-0.1175	0.0830	-0.1177	-0.7867	-0.2819	0.0282	-0.1337	-0.0028	0.0670	0.6191	0.8824	0.2877	0.0464	-0.0080	0.3320	0.7428	0.3712
VSC9	-0.6229	-0.8707	-0.8134	-0.6068	-0.8231	-0.2879	-0.8130	-0.1728	-0.4092	-0.8425	-0.8409	-0.8106	-0.8522	-0.6489	-0.8805	-0.8385	-0.8423
VSC10	0.4251	0.4855	0.2056	0.1149	0.1098	0.0920	0.4283	0.4893	0.2049	0.5922	0.4510	0.4903	0.4327	0.5175	0.3892	0.4905	0.2312

Go to *Home -> Outputs -> TRANSCOs Output -> HVDC -> VSC Modulation Index* to view the detailed hourly modulation index of the voltage source converters of the system. Besides, by selecting the different items in the dropdown list on the top left of the VSC modulation index table, a user can choose to display the VSC modulation index results of individual TRANSCOs or all TRANSCOs. The "Download Data" button allows a user to download the detailed VSC modulation index results listed in the table.

IEEE118WithWindHVDC_AC

Home > Outputs > TRANSCOs Output > HVDC > VSC Modulation Index

All TransCos Download Data

Name	H1	H2	H3	H4	H5	H6	H7	H8	H9	H10	H11	H12	H13	H14	H15	H16	H17	H18	H19	
VSC1	0.8622	0.9238	0.9081	0.8708	0.8772	0.8926	0.8691	0.8832	0.9001	0.9418	0.9385	0.9238	0.8848	0.8883	0.9144	0.9301	0.8987	0.9248	0.9345	0.7
VSC2	0.9434	0.8601	0.8772	0.8648	0.8894	0.8593	0.8908	0.9038	0.9091	0.8999	0.8698	0.8734	0.8802	0.8838	0.8814	0.8825	0.8878	0.8791	0.8618	0.1
VSC3	0.8688	0.8682	0.8471	0.8504	0.8530	0.8501	0.8544	0.8508	0.8609	0.9211	0.9338	0.9251	0.9033	0.8759	0.9248	0.8870	0.9057	0.9168	0.9454	0.1
VSC4	0.9371	0.9117	0.9231	0.9274	0.8833	0.9138	0.8949	0.8987	0.8948	0.8871	0.8965	0.8846	0.8892	0.8856	0.8873	0.8880	0.8861	0.8819	0.9004	0.1
VSC5	0.8913	0.9034	0.8627	0.8708	0.8678	0.8799	0.8873	0.8863	0.9088	0.9408	0.9294	0.9190	0.9116	0.8869	0.9570	0.8941	0.9348	0.9451	0.9228	0.1
VSC6	0.9365	0.9204	0.9124	0.8946	0.8911	0.9017	0.8891	0.8977	0.8948	0.8871	0.8978	0.8847	0.8893	0.8816	0.8868	0.8880	0.8863	0.8834	0.8988	0.1
VSC7	0.9138	0.8908	0.8567	0.8515	0.8455	0.8507	0.8809	0.8904	0.8778	0.9319	0.9317	0.9037	0.8738	0.8648	0.9127	0.8959	0.9028	0.9127	0.8894	0.1
VSC8	0.9291	0.9144	0.8817	0.8872	0.8687	0.8958	0.8667	0.8748	0.8455	0.8768	0.8558	0.8560	0.8547	0.8588	0.8740	0.8814	0.8548	0.8793	0.8471	0.1
VSC9	0.8882	0.8894	0.8192	0.8097	0.7964	0.8173	0.8532	0.8403	0.8339	0.8628	0.8459	0.8515	0.8566	0.8624	0.8894	0.8393	0.8468	0.8428	0.8547	0.1
VSC18	0.8541	0.7934	0.7977	0.8034	0.7929	0.7968	0.8009	0.7925	0.7902	0.7969	0.7959	0.7933	0.8061	0.8259	0.8349	0.7932	0.7968	0.7953	0.7980	0.1

Go to *Home* -> *Outputs* -> *TRANSCOs Output* -> *HVDC* -> *VSC Internal AC Voltage* to view the detailed hourly internal AC voltage of the voltage source converters of the system. Besides, by selecting the different items in the dropdown list on the top left of the VSC internal AC voltage table, a user can choose to display the VSC internal AC voltage results of individual TRANSCOs or all TRANSCOs. The "Download Data" button allows a user to download the detailed VSC internal AC voltage results listed in the table.

WINS

IEEE118WithWindHVDC_AC

Home > Outputs > TRANSCOs Output > HVDC > VSC Internal AC Voltage

All TransCos Download Data

Name	U1	U2	U3	U4	U5	U6	U7	U8	U9	U10	U11	U12	U13	U14	U15	U16	U17	U18	U19
VSC1	0.9916	1.0621	1.0443	1.0009	1.0088	1.0205	0.9995	1.0157	1.0353	1.0651	1.0687	1.0609	1.0177	1.0212	1.0422	1.0642	1.0328	1.0482	1.0700
VSC2	1.0774	0.9907	0.9639	0.9884	1.0184	0.9813	1.0081	1.0364	1.0408	1.0234	1.0000	1.0044	1.0104	1.0149	1.0138	1.0125	1.0104	1.0068	0.9904
VSC3	0.9823	1.0139	0.9765	0.9803	0.9809	0.9866	0.9828	0.9785	1.0105	1.0443	1.0404	1.0189	1.0094	0.9926	1.0445	1.0005	1.0331	1.0430	1.0280
VSC4	1.0776	1.0699	1.0414	1.0026	0.9961	1.0354	1.0225	1.0319	1.0291	1.0201	1.0295	1.0172	1.0228	1.0184	1.0204	1.0212	1.0193	1.0257	1.0345
VSC5	1.0238	1.0288	1.0152	1.0012	0.9980	1.0119	1.0193	1.0184	1.0427	1.0638	1.0688	1.0384	1.0377	1.0195	1.0754	1.0261	1.0586	1.0672	1.0338
VSC6	1.0778	1.0887	1.0414	1.0017	0.9960	1.0395	1.0225	1.0319	1.0291	1.0201	1.0300	1.0175	1.0227	1.0139	1.0199	1.0212	1.0192	1.0174	1.0348
VSC7	1.0495	1.0207	0.9882	0.9792	0.9723	0.9775	1.0131	1.0262	1.0061	1.0403	1.0318	1.0298	1.0029	0.9945	1.0324	0.9871	1.0212	1.0524	1.0076
VSC8	1.0617	1.0514	1.0081	0.9894	0.9866	1.0202	0.9909	1.0093	0.9724	1.0049	0.9842	0.9844	0.9829	0.9872	1.0031	1.0138	1.0371	1.0112	0.9741
VSC9	1.0524	1.0198	0.9668	0.9595	0.9548	0.9733	1.0109	1.0078	0.9953	1.0238	1.0197	1.0153	1.0051	0.9877	1.0207	1.0009	1.0053	1.0285	1.0148
VSC10	0.9704	0.9503	0.9503	0.9503	0.9503	0.9503	0.9528	0.9508	0.9548	0.9503	0.9504	0.9503	0.9503	0.9502	0.9503	0.9503	0.9503	0.9503	0.9503

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 - CSC AC Terminal MW
 - CSC AC Terminal MVAR
 - CSC AC Angle
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 - CSC DC Current
 - CSC Firing/Extinction Angle
 - CSC Transformer Tap
 - VSC AC Terminal MW
 - VSC AC Terminal MVAR
 - VSC AC Angle
 - VSC DC Voltage
 - VSC DC Current
 - VSC Modulation Index
 - VSC Internal AC Voltage
 - DC Branch Current
 - DC Branch Flow PT

Go to *Home* -> *Outputs* -> *TRANSCOs Output* -> *HVDC* -> *DC Branch Current* to view the detailed hourly current of the DC lines of the system. Besides, by selecting the different items in the dropdown list on the top left of the DC branch current table, a user can choose to display the DC branch current results of individual TRANSCOs or all TRANSCOs. The "Download Data" button allows a user to download the detailed DC branch current results listed in the table.

Home > Outputs > TRANSCOs Output > HVDC > DC Branch Current

Download Data

Name	H1	H2	H3	H4	H5	H6	H7	H8	H9	H10	H11	H12	H13	H14	H15	H16	H17
DCBRANCH1	0.1545	0.4868	-0.5670	0.1278	0.1895	0.1576	0.3666	0.0645	-0.1620	-0.3779	-0.2254	-0.0523	0.0438	0.0497	-0.2067	-0.0032	0.0
DCBRANCH2	-0.3664	-0.0931	0.4376	1.3796	0.4461	0.3334	0.1504	0.0344	-0.0579	-0.3253	-0.7106	-0.9717	-0.6509	-0.3362	-0.4122	-0.4411	-0.0
DCBRANCH3	-0.0300	-0.2061	0.1731	0.3488	0.6464	0.0330	-0.0248	-0.0079	-0.0500	-0.3721	0.0551	-0.3043	-0.2327	-0.0097	-0.5249	-0.0413	-0.0
DCBRANCH4	0.1175	-0.0639	0.1177	0.7867	0.2819	-0.0202	0.1337	0.0026	-0.0670	-0.4195	-0.8534	-0.2077	-0.0464	0.0093	-0.3520	-0.7428	0.0
DCBRANCH5	-0.6129	-0.4307	-0.8134	-0.6066	-0.8231	-0.2079	-0.8110	-0.1728	-0.4092	-0.8425	-0.8409	-0.0306	-0.8522	-0.8489	-0.4888	-0.8995	-0.0
DCBRANCH6	-0.1978	-0.3531	-0.6037	-0.4996	0.2098	-0.1959	0.3827	0.3167	-0.1242	-0.2603	-0.3839	-0.3482	-0.4294	-0.3313	-0.0992	-0.3480	-0.0
DCBRANCH7	0.0906	0.8354	0.8398	0.8240	0.8393	0.8390	0.7418	0.8216	0.8364	0.8393	0.8377	0.8354	0.8408	0.8396	0.8398	0.8393	0.8
DCBRANCH8	-0.4714	-0.0947	-1.0640	-1.0143	-0.8657	-0.5866	-0.5747	0.8134	-0.4356	-0.6999	-0.6981	-0.0637	-0.5038	-0.8911	-0.5051	-0.8788	-0.0
DCBRANCH9	0.0799	-0.7109	0.0107	-0.0702	-0.8750	0.3045	0.8401	0.1131	0.3311	0.8383	0.3798	0.2999	-0.8194	0.6059	-0.0677	-0.1995	0.0
DCBRANCH10	-0.6832	0.3802	-0.7023	-0.9109	0.5004	-0.6833	-0.9845	0.3289	-0.3538	-0.7978	-0.5283	-0.0403	0.3937	-1.0754	0.1330	-0.0447	-0.0

Go to *Home -> Outputs -> TRANSCOs Output -> HVDC -> DC Branch Flow FT(TF)* to view the detailed hourly branch flow of the DC lines of the system. Besides, by selecting the different items in the dropdown list on the top left of the DC branch flow table, a user can choose to display the DC branch flow results of individual TRANSCOs or all TRANSCOs. The "Download Data" button allows a user to download the detailed DC branch flow results listed in the table.

The screenshot shows the WINS web application interface. The breadcrumb navigation path is: Home > Outputs > TRANSCOs Output > HVDC > DC Branch Flow FT. The table displays DC branch flow results for all TRANSCOs, with columns for Name, H1, H2, H3, H4, H5, H6, H7, H8, H9, H10, H11, H12, H13, H14, H15, H16, H17, and a final column for the flow value. The table is titled "IEEE118WithWindHVDC_AC".

Name	H1	H2	H3	H4	H5	H6	H7	H8	H9	H10	H11	H12	H13	H14	H15	H16	H17	
DCBRANCH1	17.77	55.98	65.21	14.69	21.74	18.13	42.35	5.12	11.79	-42.74	-25.46	-4.00	5.04	5.72	-23.33	-9.52	-3.70	-2
DCBRANCH2	-41.47	-19.67	58.32	159.65	51.30	18.33	17.30	3.94	-4.59	-26.40	-79.22	-137.02	-72.73	-18.19	-44.56	-49.75	-21.04	-2
DCBRANCH3	-3.45	-27.49	15.91	40.19	74.34	3.79	-2.85	-0.90	-5.74	-42.10	6.34	-34.53	-25.49	-1.12	-50.98	-4.75	-40.00	-9
DCBRANCH4	13.60	-9.51	13.53	90.48	32.42	-2.32	15.37	6.93	-7.69	-69.12	-54.40	-23.67	-5.33	1.07	-17.55	-62.66	-42.00	-1
DCBRANCH5	-70.54	-99.99	-96.47	-71.50	-2.77	-34.28	-96.08	-28.71	-49.85	-99.99	-99.99	-99.99	-99.99	-97.24	-55.43	-100.00	-99.99	-9
DCBRANCH6	-22.47	-42.28	-71.99	-59.19	18.29	-23.36	-45.52	38.00	-14.86	-31.02	-46.56	-41.70	-59.61	-18.12	-11.29	-41.47	-72.85	-6
DCBRANCH7	100.07	100.06	100.07	97.99	100.06	100.07	98.27	96.53	100.06	100.07	100.06	100.06	100.06	100.07	100.06	100.07	100.06	10
DCBRANCH8	-53.57	-91.38	-127.03	-120.61	-97.77	-69.96	-68.39	1.89	-52.11	-62.25	-83.15	-103.40	-99.36	-103.55	-97.47	-105.27	-105.58	-9
DCBRANCH9	100.07	-86.21	1.29	-8.36	-104.32	-36.35	105.07	13.56	39.84	100.07	45.42	-34.78	-98.61	69.83	-7.71	-22.66	8.59	8
DCBRANCH10	-75.43	-45.60	-83.82	-139.45	60.50	-81.57	-117.27	39.45	-42.33	95.23	-63.18	-7.20	-47.18	-223.95	11.73	-5.16	-78.56	-4

Home > Outputs > TRANSCOs Output > HVDC > DC Branch Flow TF - Mozilla Firefox

http://216.47.134.23/WINS/DCBranchFlowTF.aspx

WINS

IEEE118WithWindHVDC_AC

Home > Outputs > TRANSCOs Output > HVDC > DC Branch Flow TF

All TransCos Download Data

Name	P1	P2	P3	P4	P5	P6	P7	P8	P9	P10	P11	P12	P13	P14	P15	P16	P17	P18
DCBRANCH1	-17.65	-54.88	-63.88	-14.61	-21.56	-18.00	-41.48	-5.11	-11.88	-43.48	25.92	-6.02	-5.03	-5.71	23.54	9.56	-3.70	26.43
DCBRANCH2	42.14	10.71	-49.38	-149.13	-50.31	-37.77	-17.13	-3.95	5.80	37.43	81.75	111.74	74.85	38.66	47.41	50.73	21.41	28.47
DCBRANCH3	3.48	23.78	-19.76	-39.50	-72.25	-3.79	2.85	0.80	5.76	-42.79	-6.33	35.00	26.77	1.11	68.38	4.75	-40.82	101.62
DCBRANCH4	-13.43	9.54	-13.46	-67.38	-32.62	2.32	-15.28	-8.32	7.71	71.04	98.03	23.89	5.34	-1.57	38.10	85.42	42.89	16.57
DCBRANCH5	75.78	108.42	96.86	72.10	2.77	34.33	96.48	20.73	48.95	100.42	100.41	100.42	100.42	97.67	85.57	108.42	108.42	108.42
DCBRANCH6	22.48	42.29	71.94	80.22	-10.28	23.36	45.54	-57.99	14.86	31.03	46.57	41.71	50.62	38.13	11.29	41.89	72.89	60.93
DCBRANCH7	-108.00	-99.99	-99.99	-97.92	-99.99	-99.99	-88.22	-98.46	-99.99	-99.99	-99.99	-99.99	-99.99	-99.99	-108.00	-99.99	-99.99	-99.99
DCBRANCH8	53.61	96.91	127.14	110.82	67.84	70.03	68.46	-1.81	53.15	82.25	83.24	103.35	95.48	100.71	57.52	108.42	108.74	97.70
DCBRANCH9	-99.99	86.27	-1.20	8.36	105.03	-16.34	-100.00	-13.56	-39.83	-99.99	-45.48	34.79	96.68	-89.00	7.71	22.86	-8.59	-5.79
DCBRANCH10	75.78	-45.49	84.22	110.13	-39.80	81.95	118.35	-39.36	42.43	95.73	63.40	7.28	-47.03	124.88	-11.72	5.37	79.91	41.76

Home > Outputs > TRANSCOs Output > HVDC > DC Branch Flow TF

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 - CSC DC Voltage
 - CSC DC Current
 - CSC Firing/Extinction Angle
 - CSC Transformer Tap
 - VSC AC Terminal MW
 - VSC AC Terminal MVAR
 - VSC AC Angle
 - VSC DC Voltage
 - VSC DC Current
 - VSC Modulation Index
 - VSC Internal AC Voltage
 - DC Branch Current
 - DC Branch Flow PT
 - DC Branch Flow TF

Go to *Home* -> *Outputs* -> *TRANSCOs Output* -> *HVDC* -> *DC Branch Loss* to view the detailed hourly power loss of the DC lines of the system. Besides, by selecting the different items in the dropdown list on the top left of the DC branch loss table, a user can choose to display the DC branch power loss results of individual TRANSCOs or all TRANSCOs. The "Download Data" button allows a user to download the detailed DC branch power loss results listed in the table.

WINS

IEEE118WithWindHVDC_AC

Home > Outputs > TRANSCOs Output > HVDC > DC Branch Loss

All TransCos Download Data

Name	H1	H2	H3	H4	H5	H6	H7	H8	H9	H10	H11	H12	H13	H14	H15	H16	H17	H18	H19	H20	H21	H22	H23	H24	Qtotal
DCBRANCH1	0.11	1.18	1.69	0.98	0.17	0.12	0.67	0.60	0.05	0.71	0.25	0.01	0.00	0.03	0.20	0.03	0.00	0.26	0.05	0.00	1.10	0.41	1.05	0.13	105
DCBRANCH2	0.67	0.04	0.95	9.51	0.99	0.55	0.11	0.00	0.01	0.52	1.57	4.72	2.11	0.54	0.84	0.97	0.17	0.30	7.03	11.34	7.02	0.94	0.14	0.54	105
DCBRANCH3	0.00	0.21	0.14	0.40	2.00	0.00	0.00	0.00	0.01	0.69	0.01	0.46	0.27	0.00	1.37	0.00	0.62	3.90	1.73	7.36	0.36	0.00	0.00	0.42	105
DCBRANCH4	0.06	0.03	0.06	3.39	0.39	0.00	0.00	0.00	0.02	1.91	3.63	0.21	0.01	0.00	0.55	1.75	0.68	0.13	0.50	1.59	15.12	1.38	0.04	2.40	105
DCBRANCH5	0.23	0.42	0.09	0.22	0.00	0.04	0.38	0.01	0.10	0.42	0.42	0.42	0.43	0.43	0.54	0.42	0.42	0.42	0.35	0.40	0.18	0.00	0.37	0.42	105
DCBRANCH6	0.00	0.01	0.01	0.02	0.00	0.00	0.01	0.01	0.00	0.00	0.01	0.01	0.01	0.01	0.00	0.01	0.03	0.22	0.00	0.01	0.00	0.02	0.00	0.01	105
DCBRANCH7	0.07	0.06	0.07	0.06	0.06	0.07	0.05	0.06	0.06	0.07	0.07	0.06	0.07	0.07	0.07	0.06	0.07	0.07	0.07	0.07	0.06	0.06	0.07	0.07	105
DCBRANCH8	0.04	0.12	0.22	0.20	0.06	0.04	0.04	0.00	0.03	0.09	0.09	0.14	0.13	0.15	0.08	0.13	0.13	0.13	0.06	0.00	0.07	0.12	0.12	0.21	105
DCBRANCH9	0.07	0.09	0.09	0.00	0.07	0.09	0.07	0.00	0.01	0.07	0.01	0.00	0.04	0.03	0.00	0.00	0.00	0.00	0.07	0.07	0.00	0.00	0.04	0.00	105
DCBRANCH10	0.15	0.11	0.38	0.67	0.20	0.37	0.77	0.08	0.10	0.55	0.22	0.00	0.12	0.92	0.00	0.00	0.34	0.09	0.75	0.52	0.00	0.13	0.11	0.20	105

Go to *Home -> Outputs -> TRANSCOs Output -> HVDC -> DC Bus Voltage* to view the detailed bus voltage magnitude of the DC lines of the system. Besides, by selecting the different items in the dropdown list on the top left of the DC bus voltage magnitude table, a user can choose to display the DC bus voltage magnitude results of individual TRANSCOs or all TRANSCOs. The "Download Data" button allows a user to download the detailed DC bus voltage magnitude results listed in the table.

The screenshot displays the WINS web application interface. The breadcrumb trail at the top reads: *Home > Outputs > TRANSCOs Output > HVDC > DC Bus Voltage*. The left navigation menu shows the following structure:

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 - TRANSCOs Output
 - Branch Flows
 - Phase Shifter
 - Tap Changer
 - Bus Voltage Magnitude
 - Bus Voltage Angle
 - HVDC
 - CSC AC Terminal HW
 - CSC AC Terminal MVAR
 - CSC AC Angle
 - CSE DC Voltage
 - CSE DC Current
 - CSE Firing/Extinction Angle
 - CSC Transformer Tap
 - VSC AC Terminal HW
 - VSC AC Terminal MVAR
 - VSC AC Angle
 - VSC DC Voltage
 - VSC DC Current
 - VSC Modulation Index
 - VSC Internal AC Voltage
 - DC Branch Current
 - DC Branch Flow PT
 - DC Branch Flow TF
 - DC Branch Loss
 - DC Bus Voltage

The main content area shows a table titled "IEEE118WithWindHVDC_AC" with the following data:

DC Bus	H1	H2	H3	H4	H5	H6	H7	H8	H9	H10	H11	H12	H13	H14	H15	H16	H17	H18
DCBUS1	1.1500	1.1500	1.1500	1.1493	1.1500	1.1499	1.1500	1.1500	1.1500	1.1511	1.1387	1.1473	1.1500	1.1500	1.1397	1.1442	1.1491	1.1337
DCBUS2	1.1422	1.1216	1.1218	1.1429	1.1405	1.1420	1.1316	1.1477	1.1448	1.1500	1.1500	1.1470	1.1475	1.1500	1.1483	1.1475	1.1452	1.1500
DCBUS3	1.1316	1.1453	1.1500	1.1500	1.1500	1.1497	1.1500	1.1500	1.1471	1.1337	1.1144	1.1013	1.1174	1.1333	1.1193	1.1275	1.1408	1.1376
DCBUS4	1.1500	1.1500	1.1261	1.1610	1.1276	1.1330	1.1424	1.1481	1.1500	1.1500	1.1500	1.1495	1.1500	1.1500	1.1500	1.1500	1.1500	1.1500
DCBUS5	1.1494	1.1396	1.1500	1.1497	1.1500	1.1500	1.1487	1.1491	1.1474	1.1313	1.1500	1.1347	1.1303	1.1495	1.1237	1.1479	1.1323	1.1057
DCBUS6	1.1500	1.1500	1.1413	1.1323	1.1176	1.1403	1.1500	1.1495	1.1500	1.1500	1.1472	1.1500	1.1500	1.1500	1.1500	1.1500	1.1500	1.1500
DCBUS7	1.1484	1.1458	1.1500	1.1500	1.1500	1.1489	1.1500	1.1499	1.1466	1.1164	1.1073	1.1296	1.1476	1.1500	1.1311	1.1128	1.1314	1.1417
DCBUS8	1.1428	1.1500	1.1441	1.1106	1.1359	1.1500	1.1433	1.1497	1.1500	1.1473	1.1500	1.1500	1.1500	1.1491	1.1477	1.1500	1.1500	1.1500
DCBUS9	1.1324	1.1922	1.1058	1.1050	1.1979	1.1907	1.1947	1.1907	1.1937	1.1868	1.1888	1.1924	1.1732	1.1453	1.1347	1.1925	1.1871	1.1908
DCBUS10	1.1363	1.1973	1.1908	1.1886	1.1980	1.1924	1.1996	1.1997	1.1961	1.1919	1.1938	1.1974	1.1783	1.1504	1.1377	1.1975	1.1922	1.1958

3.6.3 Outputs – LMP

Go to *Home* -> *Outputs* -> *LMP* to view the detailed hourly locational marginal prices (LMPs) of the system in both tabular and graphical forms.

When a user clicks on the buttons on the bottom of the table with text from "Hour1" to "Hour24", the single hour LMPs curve of all buses will be plotted, as shown in the following page. A user could choose the range of the buses to be displayed on the graph.

Home > Outputs > LMP - Mozilla Firefox

File Edit View History Bookmarks Tools Help

http://216.47.134.23/WINS/LMP.aspx

Home > Outputs > LMP

LMP Graph

LMP Graph

HL, Logout My Account Sign Out

E118WithWindHVDC_AC

HL > LMP

12 11 10 9 8 7 6 5 4 3 2 1

	B3	B4	B5	B6	B7	B8	B9	B10	B11	B12	B13	B14	B15	B16	B17	B18	B19	B20	B21	B22	B23	B24	24 Hours LMP	
A5	39.44	39.29	36.59	40.94	41.11	42.32	42.99	44.16	44.16	43.31	42.99	42.31	44.16	45.02	43.72	49.82	56.36	56.47	119.67	48.29	47.74	43.58	43.58	24h LMPs
A5	39.44	39.29	36.59	40.64	41.11	42.32	42.89	44.16	44.16	43.31	42.87	42.32	44.16	45.02	43.67	49.82	56.36	56.47	119.62	48.29	47.57	43.55	43.55	24h LMPs
A5	39.44	39.29	36.59	40.91	41.11	42.32	42.92	44.16	44.16	43.31	42.90	42.31	44.16	45.02	43.70	49.82	56.36	56.47	119.79	48.29	47.68	43.57	43.57	24h LMPs
A5	39.44	39.29	36.59	40.78	41.11	42.32	42.82	44.16	44.16	43.31	42.91	42.31	44.16	45.02	43.65	49.82	56.36	56.47	119.62	48.29	47.46	43.53	43.53	24h LMPs
A5	39.44	39.29	36.59	40.67	41.11	42.32	42.81	44.16	44.16	43.31	42.80	42.31	44.16	45.02	43.64	49.82	56.36	56.47	119.62	48.29	47.40	43.50	43.50	24h LMPs
A5	39.44	39.29	36.59	40.69	41.11	42.32	42.85	44.16	44.16	43.31	42.84	42.31	44.16	45.02	43.66	49.82	56.36	56.47	117.73	48.29	47.52	43.54	43.54	24h LMPs
A5	39.44	39.29	36.59	40.59	41.11	42.32	42.89	44.16	44.16	43.31	42.83	42.31	44.16	45.02	43.65	49.82	56.36	56.47	118.44	48.29	47.49	43.54	43.54	24h LMPs
A5	39.44	39.29	36.59	40.13	41.11	42.32	42.79	44.16	44.16	43.31	42.75	42.31	44.16	45.02	43.50	49.82	56.36	56.47	114.34	48.29	47.16	43.48	43.48	24h LMPs
A5	39.44	39.29	36.59	39.22	41.11	42.32	42.73	44.16	44.16	43.31	42.66	42.31	44.16	45.02	43.46	49.82	56.36	56.47	114.81	48.29	46.82	43.42	43.42	24h LMPs
A5	39.44	39.29	36.59	38.61	41.11	42.32	42.68	44.16	44.16	43.31	42.59	42.31	44.16	45.02	43.41	49.82	56.36	56.47	114.67	48.29	46.65	43.19	43.19	24h LMPs
Hour2	Hour3	Hour4	Hour5	Hour6	Hour7	Hour8	Hour9	Hour10	Hour11	Hour12	Hour13	Hour14	Hour15	Hour16	Hour17	Hour18	Hour19	Hour20	Hour21	Hour22	Hour23	Hour24		

While when a user click on the "24h LMP" button at the end of each record as shown in the above page, the 24-hour LMPs curve of the chosen bus will be plotted, as shown in the following page.

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Analysis of 2030 Large-Scale Wind Energy Integration in the Eastern Interconnection Using WINS

A simulation of the 2030 load forecast in the Eastern Interconnection suggests that large-scale wind energy integration will have a major impact on the hourly commitment and dispatch of gas and coal units, especially at off-peak load hours. While fuel price alterations will have major impacts on the system production cost, load variation will have a larger impact and potential carbon costs will have the greatest impact.

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I. Introduction

Wind energy is an important component of the future energy production portfolio throughout the world. In the United States, wind energy is expected to provide 20 percent of the U.S. energy production portfolio by 2030 [1–3]. However, the electricity market requires a detailed simulation of the economics and the adequacy of the

energy production portfolio before large-scale wind energy can be integrated into existing power systems.

The U.S. Eastern Interconnection is the largest interconnection in the world with more than 5,000 generating units and about 70,000 branches. The National Renewable Energy Laboratory (NREL) initiated a study in 2008 to examine the impact of 20–30 percent wind

energy integration in the Eastern Interconnection [4]. The western wind and solar integration study in 2007 examined the operational impact of 35 percent renewable energy penetration [5]. The impact of wind energy integration on power system operations is analyzed further in [6,7,15]. An hourly unit commitment and economic dispatch model for analyzing large-scale power system operations was represented in [8]. A follow-up optimization-based security-constrained unit commitment (SCUC) model [16–18] was presented in [9] which took into account the intermittency and volatility of wind power generation and transmission network constraints.

In this article, we focus on large-scale wind energy integration in the Eastern Interconnection in 2030. The wind energy sites are analyzed and the impact of large-scale wind energy integration on existing generation resources and production costs is studied. Fuel

price sensitivity, wind energy production sensitivity, load growth sensitivity, carbon cost sensitivity, and load management strategies are considered and analyzed for large-scale wind energy integration.

The rest of the article is organized as follows. Section II describes the proposed methodology, assumptions, and relevant evaluation metrics. Section III presents the wind energy integration study results for the Eastern Interconnection. The conclusions drawn from the study are provided in Section IV.

II. Methodology for Wind Energy Integration

A. WINS

At the Illinois Institute of Technology (IIT), we had developed over the years an efficient decision tool called POMS (POwer Market Simulator) [10] for the day-ahead scheduling of large-

scale power systems. The expansion of POMS, which is referred to as WINS (Wind INtegration Simulator), is considered in this study to support the collaborative planning, analysis, and implementation of large-scale wind energy integration in the United States. The WINS architecture is depicted in Figure 1. WINS applies unit commitment to simulate large-scale wind energy integrations in the hourly power system operation. The application of WINS in this article analyzes the impact of large-scale wind energy integration in the year 2030 on production costs, unit commitment, and dispatch of generation resources in the Eastern Interconnection. For the purpose of this energy adequacy study, we do not consider transmission constraints in this article. We use the wind data given in [4]. A brief description of the wind data is given in [12]. The wind forecast uncertainty is simulated in this article by

Figure 1: Framework of WINS

Figure 2: Potential Wind Sites in the Eastern Interconnection

sensitivity analyses applied to the wind energy integration Scenarios.

B. Input data

It is estimated that approximately 225 GW of wind power generation is required to supply 20 percent, and 330 GW is required to supply 30 percent, of the total energy by 2024 in the Eastern Interconnection [4]. In this article, we utilize the land-based time series wind simulation results [4]. The potential land-based wind sites in the Eastern Interconnection are shown in **Figure 2** for about 580 GW of wind power generation capacity. The figure shows that there are potential wind energy sites with rich wind resources in the central part of the United States. In this study, we consider a 1.28 percent annual load growth rate which is based on the MTEP 08 (MISO Transmission Expansion Planning) assumptions. The hourly load distribution shown in

Figure 3 is based on the MISO's hourly load profile in 2007. In **Figure 3**, peak loads appear in July and August. The power flow solution is used for calculating the hourly load distribution at each bus. Fuel prices are assumed to

Figure 3: Annual Hourly Load Profile

Figure 4: Hourly Production Cost Without Wind Integration

increase at an annual rate of 4 percent for oil and gas, 2 percent for coal, and 3 percent for nuclear fuel based on the fuel price given in 2008 [13].

C. Evaluation metrics

The evaluation criteria and metrics used in our simulations are defined as follows.

1. Wind Energy Availability

The available wind energy is treated as dispatchable in WINS simulations. Here,

$$(1)P_A = \sum_{t=1}^T \sum_{i=1}^{NG} p_i^{\max} w_{it} \text{ where } T$$

represents the number of hours in a period (e.g., one year), NG represents the number of wind generators/farms, $p_i^{\max}$ is the

nominal capacity of wind generator/farm i , w_{it} represents the wind power generation i at time t , P_A represents the system wind energy availability in the given study period.

We assume the available wind energy is much less than the total system load in the Eastern Interconnection. Therefore, the total available wind energy is to be dispatchable without any curtailment.

2. Percentage of Wind Energy Contribution

This metric (2) is to evaluate the percentage of wind energy contribution to the total energy utilized for supplying the load in the power system.

$$= \frac{\text{Wind Energy}}{\text{Total Energy}} \times 100\% \quad (2)$$

III. Numerical Results

In this section, we utilize WINS to simulate the wind energy integration in the Eastern Interconnection of the United States based on the methodology presented in Section II.

A. Level of wind energy integration

We simulate the hourly power system operation using WINS for a given wind power capacity factor (CF). Four Scenarios are studied as follows.

Scenario 1: No wind energy integration is considered.

Scenario 2: Wind energy integration with a minimum CF of 40 percent is considered.

Figure 5: Potential Wind Sites with $CF \geq 40\%$

Figure 6: Monthly Wind Energy and its Contribution to Total Energy

Scenario 3: Wind energy integration with a minimum CF of 30 percent is considered.

Scenario 4: Wind energy integration in all potential sites is considered.

1. No Wind Integration

This is the base case in which the hourly loads will be served by fossil fuel and hydro units.

Figure 4 shows the hourly production cost which is \$217.5

Figure 7: Wind Energy Contribution at Peak/Off-Peak Hours

billion per year with an average production cost of \$45.64/MWh. The production cost will not change linearly with the hourly load fluctuations. Hydro units will have zero costs and be scheduled first to serve hourly loads or reserves; then cheaper units such as nuclear, coal, and large oil will be committed as loads pick up, and finally expensive units such as gas and oil will be committed to supply hourly loads. A higher production cost will occur at annual peak hours of 5,000–5,500 (i.e., July and August). The production cost at peak hours (6 AM–10 PM) will be \$177.8 billion and the production cost at off-peak hours (11 PM–5 AM) will be \$39.7 billion. The average production costs at peak/off-peak hours are \$50.2/MWh and \$32.5/MWh. The average production cost at peak load hours is higher when expensive generators are committed and dispatched.

2. Integration of Wind Energy Sites with a Minimum CF of 40 Percent

There are 399 such potential wind energy sites with a total wind generation capacity of 230.5 GW. The largest annual CF is 49 percent. **Figure 5** shows the 399 potential wind energy sites in the Eastern Interconnection in which wind energy resources are mainly located remotely in the central region of the United States. The total available wind energy with a minimum 40 percent CF in that region is 845.2 TWh.

Figure 8: Hourly Production Cost in Scenario 2

Figure 9: Potential Wind Sites with $CF \geq 30\%$

The 2030 energy forecast in the Eastern Interconnection is 4,783.2 TWh, which indicates that the potential wind energy is about 17.67 percent of the total

energy production portfolio. We assume the wind energy has zero fuel cost and transmission congestion is not considered. So the entire available wind energy

Figure 10: Monthly Wind Energy and its Contribution to Total Energy

will be dispatched to satisfy the hourly load. **Figure 6** shows the monthly wind energy in 2030. The wind energy resources are mostly available in spring and winter; however, peak loads occur in summer. January has the highest level of available wind energy of 86.4 TWh, which amounts to 21.11 percent, of the total energy. March has the highest percentage for wind energy contribution (21.53 percent) because the load is lower than that of January. The available wind energy is scarce in August while the highest level of load occurs in this month. So August represents the month with the least available wind energy and the percentage of wind energy contribution (i.e., 57.5 TWh and 12.2 percent) to the total energy production portfolio.

Figure 7 shows the wind energy contribution at peak and off-peak hours. The figure shows that the wind is usually rich at night as compared with that in the daytime, especially in the summer. The hourly average wind energy at peak/off-peak hours are 2.27 TWh and 2.69 TWh in August, and the percentages of wind energy contribution are 10.88 percent and 16.22 percent, respectively. **Figure 8** shows the hourly production cost. Compared to **Figure 4**, the production cost is lower when the large-scale wind energy is integrated. The annual production cost is \$130.4 billion, which is about \$87.1 billion less than that in Scenario 1. The annual average production cost decreases from \$45.64/MWh to

Figure 11: Wind Energy Contribution at Peak/Off-Peak Hours

Figure 12: Hourly Production Cost in Scenario 3

\$27.25/MWh when the wind energy is integrated. Here, the production costs at peak/off-peak hours are \$107.1 billion and \$23.2 billion, and the average production cost at peak/off-peak hours are \$30.1/MWh and \$18.9/MWh respectively. The average

production cost is lower in this Scenario at peak/off-peak hours.

3. Integration of Wind Energy Sites with a Minimum CF of 30 Percent

In this case, 972 wind sites are introduced in **Figure 9** with a total

Figure 13: Monthly Wind Energy and its Contribution to Total Energy

capacity of 481.5 GW. Compared to Figure 5, additional wind energy sites located in Wisconsin, Illinois, Indiana, and other regions are considered in this Scenario.

Figure 10 shows that the annual wind energy contribution is 1,596 TWh, which amounts to 33.37 percent of the total energy production portfolio. Figure 11 shows the monthly wind energy contribution at peak/off-peak hours. Compared to the simulation results in Scenario 2, 573 additional potential wind energy sites with a total capacity of 251 GW are added here with a CF between 30 percent and 40 percent. In this case, the added wind generation capacity is 108.9 percent (i.e., 481.5 GW vs. 230.5 GW) while the added wind energy contribution is about 88.85 percent (i.e., 33.37 percent vs. 17.67 percent). The production cost in Figure 12 is \$86.8 billion with an average hourly production cost of \$18.14/MWh. The average production costs at peak/off-peak hours are \$20.33/MWh and \$11.33/MWh, respectively.

4. Integration in All Potential Wind Energy Sites

There are 1,326 wind energy sites in the Eastern Interconnection with a total capacity of 580 GW. Figure 13 shows the monthly wind energy production and wind energy contribution. The annual wind energy production is about 1,816 TWh and the annual percentage of wind energy contribution is about 38 percent. In this case, the minimum wind

Figure 14: Wind Energy Contribution at Peak/Off-Peak Hours

Figure 15: Hourly Production Cost in Scenario 4

Figure 16: Energy Production Portfolios in Wind Integration Scenarios

Figure 17: Energy Provided by Gas Units in Wind Integration Scenarios

Figure 18: Energy Provided by Coal Units in Wind Integration Scenarios

energy contribution will be more than 20 percent of the system load. **Figure 14** shows the percentage of wind energy contribution at peak/off-peak hours. Here, the wind energy contribution to the total energy at peak hours in August is 21.33 percent, which is also the lowest period for the wind energy production. The wind energy in this period is 75.83 TWh as compared to 38.67 TWh in Scenario 2 and 68.52 TWh in Scenario 3. The annual production cost is \$77 billion.

Figure 19: Hourly Wind Energy in Wind Integration Scenarios

Figure 15 shows the hourly production cost with an average production cost of \$16.1/MWh, and peak/off-peak average production costs of \$18.19/MWh and \$10.04/MWh, respectively. Compared to the simulation results in Scenarios 1–3, the production costs has dropped here as more wind energy sites are added. **Figure 16** shows the wind energy contribution in all four Scenarios. Here, the gas unit production has decreased as more wind energy is considered. Also, the energy supplied by coal units is lower as they are replaced by the integrated wind energy units. **Figures 17–19** show the energy supplied by gas, coal, and wind units in four Scenarios. These figures show that wind energy will replace some of the fossil energy especially at off-peak hours in the Eastern Interconnection. **Figure 20** show the annual commitment results of existing power plants in four Scenarios, in which red dots represents the power plants in

Figure 20: Unit Commitment Results in Wind Integration Scenarios

which at least one unit is committed for a minimum of one hour per year. Also, blue dots show the plants which will be off throughout the year as more wind energy is integrated in the Eastern Interconnection.

B. Sensitivity analysis

There are several uncertain energy factors in the Eastern Interconnection, including fuel prices, hourly wind speed [11], hourly loads, and carbon costs, which could have major impacts on the large-scale wind energy integration and the energy production portfolio. It is

perceived that an accurate forecast for some of these factors might not be readily available. In this section, we apply sensitivity analyses, based on our simulation

results given in Section A2, to study the impact of fluctuations in such factors on the wind energy integration and the annual energy production portfolio in the

Figure 21: Production Costs in Fuel Cost Scenarios

Eastern Interconnection. The simulation results given in Section A2 are considered as the base case in this section.

1. Fuel Price Sensitivity

We apply the sensitivity analysis to the WINS simulation results for 2030, given in Section A2, in which the potential wind energy sites with a minimum CF of 40 percent and a total energy contribution of 17.67 percent (which is close to the expected 20 percent wind contribution in 2030) were considered. The following four Scenarios would consider the impact of fuel price forecast.

Scenario 5: Actual fuel price is 20 percent lower than the forecast

Scenario 6: Actual fuel price is 10 percent lower than the forecast

Scenario 7: Actual fuel price is 10 percent higher than the forecast

Scenario 8: Actual fuel price is 20 percent higher than the forecast

As expected, the fuel price escalation has no impact on the wind energy dispatch since the wind energy has a zero price and will always be dispatched. However, the production cost in Figure 21 will increase as fuel prices increase. The increase in fuel price at peak hours will have a more pronounced impact on the production cost as more expensive units will be committed.

2. Wind Energy Production Sensitivity Analysis

We apply the sensitivity analysis to the 2030 simulation results in Section A2. Four Scenarios are studied as follows.

Figure 22: Wind/Non-Wind Energy in Wind Energy Scenarios

Figure 23: Production Cost in Wind Energy Production Scenarios

Figure 24: Energy Production Portfolios in Wind Energy Production Scenarios

Scenario 9: Actual wind energy production is 20 percent lower than the forecast

Scenario 10: Actual wind energy production is 10 percent lower than the forecast

Scenario 11: Actual wind energy production is 10 percent higher than the forecast

Scenario 12: Actual wind energy production is 20 percent higher than the forecast

Figure 22 shows that the wind energy contribution to the total energy production is about 20 percent when the actual wind energy is 10 percent higher than that in the base case.

Figure 23 shows that the total production cost decreases with the added wind energy production. Again, the production cost is more sensitive to the wind energy production at peak hours. **Figure 24** shows the energy production portfolios in all four Scenarios. The energy produced by gas and coal units will decrease as the wind energy production is higher. Similar to that in **Figure 22**, the wind energy contribution is increased from 14 percent to 22 percent. The unit commitment and hourly generation dispatch show a similar pattern as that in Section A2.

3. Load Sensitivity Analysis

In this section, we study the impact of load forecast errors on the WINS base case simulation results in Section A2. We do the sensitivity analysis based the load forecast in 2030. Four Scenarios are studied as follows.

Figure 25: Wind/Non-Wind Energy in Load Scenarios

Figure 26: Production Cost in Load Scenarios

Figure 27: Energy Production Portfolios in Load Variation Scenarios

Scenario 13: Actual load is 20 percent lower than the forecast
 Scenario 14: Actual load is 10 percent lower than the forecast
 Scenario 15: Actual load is 10 percent higher than the forecast
 Scenario 16: Actual load is 20 percent higher than the forecast

The wind energy contribution, depicted in Figure 25, shows a 19.62 percent contribution to the total energy production in Scenario 14 when the actual load is 10 percent lower than the forecast. The wind energy contribution will decline as the actual load escalates because the additional load will be served by other types of units. The production costs in Figure 26, as compared to those in Sections B1 and B2, show that the system load will have the largest impact on production costs. Here, the production cost increases a lot between Scenarios 13 and 16. The production cost at peak hours is more sensitive to load variations.

Figure 27 shows the energy contribution in the given four Scenarios. The nuclear, hydro, and wind unit with their inexpensive fuel will supply much of the hourly load. However, their contributions will decline as the system load increases. Compared with the base case in Section A2, the energy contributions by gas and coal units, especially those supplied by gas units, will decrease as we reduce the system load. Furthermore, the contribution of gas units to the energy production portfolio will increase from 7 percent in the base

case (A2) to 11 percent in Scenario 15 and 17 percent in Scenario 16 as we increase the system load, which means that the additional load is mainly supplied by gas units.

Figures 28 and 29 show the hourly energy supplied by gas and coal units. In Figure 28, the energy supplied by gas units has increased as compared to that in Scenarios 13–14 especially at peak hours. In Scenario 13, gas units are mainly committed and dispatched at peak hours.

Figure 30 shows that the load

variation would have the largest impact on the commitment and the dispatch of generating units as compared to the fluctuation in fuel price or wind energy production. The commitment based on Scenarios 13–14 shows that many of the existing units will never be committed as hourly loads are lowered. On the other hand, almost all existing units will be committed when the hourly loads are higher than the forecast in Scenarios 15–16. The results indicate that the load management could introduce

Figure 28: Hourly Energy Provided by Gas Units in Load Variation Scenarios

Figure 29: Hourly Energy Provided by Coal Units in Load Variation Scenarios

Figure 30: Unit Commitment Results in Load Variation Scenarios

large incentives for improving the system operation bottlenecks and decreasing the operation costs.

4. Carbon Cost Sensitivity Analysis

Higher carbon cost can be used as an incentive for promoting the development of clean, efficient or environmentally friendly power generation portfolios [14]. The carbon cost data given in [14] is considered here as the low-carbon-cost Scenario. The high carbon cost Scenario would consider a carbon cost that is doubled. In this section, we consider wind energy sites with $CF \geq 40\%$ and $CF \geq 30\%$ for

Figure 31: Energy Production Portfolios in Carbon Cost Scenarios

analyzing the following four Scenarios.

Scenario 17: Low carbon cost is considered with a minimum CF of 40 percent for wind units

Scenario 18: High carbon cost is considered with a minimum CF of 40 percent for wind units

Scenario 19: Low carbon cost is considered with a minimum CF of 30 percent for wind units

Scenario 20: High carbon cost is considered with a minimum CF of 30 percent for wind units.

The variations in carbon cost will not change the wind energy contribution to the energy production portfolio. However, the total production cost will be much higher when we apply a higher carbon cost. The production costs for four Scenarios are \$406.8 billion, \$638 billion, \$285.7 billion, and \$448 billion. The average production cost at peak/off-peak load hours are \$89.5/MWh and \$71.7/MWh in Scenario 17, and \$140/MWh and \$113.5/MWh in Scenario 18.

Figure 31 shows the energy production portfolios in carbon cost Scenarios in which the high carbon cost will have a major impact on the energy supplied by gas and coal units. Since coal prices are lower than gas prices, the energy supplied by coal units does not change much in the low-carbon-cost Scenarios. The energy supplied by gas units increases from 9 percent in Scenario 17 to 29 percent in Scenario 18 while that of coal decreases from 45 percent to 25 percent. Similar results are obtained in Scenarios 19 and 20 when we consider wind units

Figure 32: Energy Provided by Gas Units in Carbon Cost Scenarios

Figure 33: Energy Provided by Coal Units in Carbon Cost Scenarios

Figure 34: Energy Production Portfolios in Load Shedding Scenarios

with a minimum CF of 30 percent. Figures 32 and 33 show the hourly energy supplied by gas and coal units, which are consistent with that of Figure 31. Here, gas units would be committed and dispatched in most hours when we consider high carbon costs.

C. Load management by introducing load shedding

As presented in Section B3, the hourly load variations would have a major impact on the WINS simulation results. In this section, we consider load shedding as an option to manage the system operation more efficiently at peak hours. For instance, if the hourly load were higher than 80 percent of the annual peak load, we would set it at 80 percent. Three Scenarios are considered as follows.

Scenario 21: Wind energy is not considered when load shedding is applied

Scenario 22: Wind energy with a minimum CF of 40 percent is considered when load shedding is applied

Scenario 23: Wind energy with a minimum CF of 30 percent is considered when load shedding is applied

Figure 34 shows the energy production portfolios for the three load shedding Scenarios. Figures 35–37 show that the load shedding will alter the unit commitment as compared to those in Figure 20. Here, more gas units are turned off at peak hours when load

shedding is applied. Here, there are about 1,200 gas units which would never be committed again when load shedding is considered as compared to those of the Scenarios 1, 2, and 3 in Section A. These results are

similar to those for load variation analysis given in Scenarios 13 and 14 (Section B3). Figure 38 shows the hourly energy supplied by gas units in which the gas unit dispatch is lower because of the load shedding at peak hours.

Figure 35: Unit Commitment Results in Scenario 21

Figure 36: Unit Commitment Results in Scenario 22

Figure 37: Unit Commitment Results in Scenario 23

Figure 38: Energy Provided by Gas Units

Load shedding has almost no impact on the hourly dispatch of coal units, as coal units are committed to serve the base load.

IV. Concluding Remarks

In this article, a comprehensive large-scale wind energy integration analysis is considered

Table 1: Summary of Simulations in All Scenarios

Scenarios	Wind Capacity (GW)	Wind Energy (TWh)	Wind Energy Contribution (%)	Production Cost (\$ Billion)	Average Production Cost (\$/MWh)
No wind	0	0	0	217.5	45.64
$CF \geq 40\%$	230.5	845.2	17.67	130.4	27.25
$CF \geq 30\%$	481.5	1,596	33.37	86.8	18.14
All Wind	580	1,816	38	77	16.10
Fuel price sensitivity					
20% lower	230.5	845.2	17.67	118.9	24.87
10% lower		845.2	17.67	124.7	26.06
10% higher		845.2	17.67	135.7	28.36
20% higher		845.2	17.67	141.7	29.63
Wind gen. sensitivity					
20% lower		676.1	14.14	143.7	30.03
10% lower		760.6	15.9	136.8	28.59
10% higher		929.7	19.44	130.4	25.99
20% higher		1014	21.20	124.3	24.80
Load sensitivity					
20% lower		845.2	22.07	64	16.73
10% lower		845.2	19.62	91.6	21.27
10% higher		845.2	16.29	178.5	34.65
20% higher		845.2	15.12	245.9	44.54
Carbon cost sensitivity					
Low carbon cost with 40% wind	230.5	845.2	17.67	406.8	84.97
High carbon cost with 40% wind	230.5	845.2	17.67	638	133.3
Low carbon cost with 30% wind	481.5	1,596	17.67	285.7	69.68
High carbon cost with 30% wind	481.5	1,596	17.67	448	93.59
Load management					
No wind energy with load shedding	0	0	0	208.7	44
Min 40% CF wind with load shedding	230.5	845.2	17.81	123	25.9
Min 30% CF wind with load shedding	481.5	1,596	33.53	80.6	16.97

which is based on the simulation of the 2030 load forecast in the Eastern Interconnection of the United States. The wind energy integration simulation results and their sensitivities are summarized in **Table 1**.

Here, transmission constraints are not considered when studying the wind energy production portfolios because the 2030 wind integration sites are not specified in the proposed wind energy data. Accordingly, the contribution of wind energy to the five Scenarios listed in **Table 1** is about 20 percent or higher.

The 2030 simulation results show that large-scale wind energy integration will have a major impact on the hourly commitment and the dispatch of gas and coal units, especially at off-peak load hours, since the wind energy is generally rich at such hours. More gas and coal units will be replaced by wind energy as wind units at candidate wind sites are integrated into the grid, and the system production cost will decrease along with the wind energy integration. The fuel price sensitivity simulation shows that fuel price alterations will have major impacts on the system production cost. However, load variation will have a larger impact on the simulation results. Potential carbon costs will have the largest impact on simulation results. Here, production costs will rise significantly with increasing the carbon costs, and more gas units and fewer coal

units will be committed and dispatched as carbon costs increase. Peak load shaving and demand response will have a major impact on the hourly commitment and dispatch of gas units because peak loads are mainly supplied by gas units. Also, load deferrals and smoothing out the daily load profile by introducing Smart Grid technologies (e.g., storage) will notably improve the economics and enhance the operation of power systems.■

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Security-constrained expansion planning of fast-response units for wind integration[☆]

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ABSTRACT

This paper proposes a stochastic expansion planning of fast-response thermal units for the large-scale integration of wind generation (WG). The paper assumes that the WG integration level is given and considers the short-term thermal constraints and the volatility of wind units in the planning of fast-response thermal units. The new fast-response units are proposed by market participants. The security-constrained expansion planning approach will be used by an ISO or a regulatory body to secure the optimal planning of the participants' proposed fast-response units with the WG integration. Random outages of generating units and transmission lines as well as hourly load and wind speed forecast errors are modeled in Monte Carlo scenarios. The Monte Carlo simplification methods are introduced to handle large-scale stochastic expansion planning as a tradeoff between the solution accuracy and the calculation time. The effectiveness of the proposed approach is demonstrated through numerical simulations.

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1. Introduction

The increasing socio-environmental concerns have persuaded governments to support large integrations of renewable generation in power systems by introducing mandatory Renewable Portfolio Standards (RPS) or equivalent policies [1]. The large integration of intermittent wind generation (WG) in power systems has necessitated the inclusion of more innovative and sophisticated approaches in power system operation and planning [2].

In this paper, the intermittency refers to a situation where the power output of WG is less than a minimum amount over an extended time. While the volatility points out to smaller WG fluctuations in a shorter time. A major challenge in power systems is to determine the optimal availability of reserves to compensate WG uncertainties. Without a sufficient supply of reserves, the power system may not be able to provide short-term ramping support to contain large WG variability. However, the real-time allocation of a large sum of reserves may not be feasible when considering the economics and the security of power systems. Here, the allocation of excessive thermal reserves could further increase the operating costs while thermal reserves supplied by remote generating units may not be readily accessible due to transmission constraints.

The deterministic allocation of thermal reserves (e.g., largest generation unit in the system or certain percentages of load and WG) may offer a sub-optimal solution. Large integrations of intermittent WG could further contribute to the vulnerability of power systems [3–5]. Hence, it is necessary to apply stochastic optimization methods to address major WG integration concerns such as the coordinated expansion of WG and fast-response generation units, uncertain nature of systems with WG units, and short-term operating constraints of power systems.

The operation planning of WG integration is proposed in Ref. [6]. The reliability of composite generation and transmission system with a large-scale WG integration is investigated in Ref. [7]. The Monte Carlo simulation is used in Ref. [8] to investigate the effect of wind and load forecast errors on the power system expansion planning.

However, only a few studies in the literature considered the complicated operation issues in the WG expansion planning problem. The problem in Ref. [9] provides a nonlinear wind-thermal model and applies the evolutionary programming to large-scale power systems. A coordinated wind-thermal dispatch is presented in Ref. [10] by applying the direct search method to the WG integration. A combination of branch and bound and dynamic programming is considered in Ref. [11] for a coordinated economic dispatch of wind and thermal units in isolated power systems. The impact of transmission lines on the WG expansion is discussed in Ref. [12]. The approach considers additional zonal reserves because of the WG uncertainty. The incorporation of the WG model in the optimal economic dispatch is discussed in Ref. [13]. The study in Ref. [14] considers the short-term operation along with the long-term

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planning, where renewable energy resources are operated along with conventional generating systems to satisfy certain objectives. A comprehensive study of the operation of power systems when considering the WG integration is presented in Ref. [15]. The study shows that, at the present time, frequency control is not a significant challenge when integrating WG into large power systems. However, such issues will become more of a challenge for systems with large penetrations of WG. Recently, North American Electric Reliability Corporation (NERC) released a report on the planning and the operation of power systems with large sums of WG [16].

This paper proposes a stochastic expansion planning of fast-response thermal units for the large-scale integration of WG. The level of WG integration is assumed to be given. The site and the year of installation of fast-response units are proposed by the participants. The ISO does not plan any generating units. Rather the ISO would acknowledge and optimize the proposed planning of fast-response units that would provide both the reserve capacity and the fast ramping required for large WG integrations. The fast-response units in the paper assumed to have the ability to reach their maximum capacity in a short period. The inclusion of the hourly unit commitment is essential when considering the WG variations and ramping constraints. The paper considers the short-term thermal constraints and the volatility of wind units in the planning model and applies a decomposition model for utilizing the hourly unit commitment states. Random outages of generating units and transmission lines as well as load and wind speed forecast errors are modeled in scenarios using the Monte Carlo simulation. The Monte Carlo simplification methods are introduced to handle large-scale the stochastic expansion planning as a tradeoff between accuracy and calculation time. The proposed stochastic generation expansion planning approach would inherently form a large-scale optimization problem and a decomposition method is used to alleviate the calculation burdens. The application of mixed-integer programming (MIP) presents attractive features including a fast convergence, simplicity of the model, linearity of constraints, and the ability to handle large-scale problems [17]. The approach can be used by an ISO or a regulatory body to secure the optimal planning of fast-response units proposed by market participants while considering the large-scale WG integration. The contribution of the paper is to consider and utilize new fast-response generating units in power systems that would accommodate large WG integrations. The impact of WG dispersion (i.e., centralized or distributed) on the power system operation and planning is investigated. The planning problem, when considering the WG uncertainty, would present a large-scale problem with major computation burdens. Several improvements in decomposition and modeling are considered in this paper to make the proposed approach more practical.

Other alternatives such as the demand response and the application of storage systems may accommodate the WG uncertainty. However, such alternatives are usually available in small quantities as compared with large WG variations in power systems [18,19]. The application of responsive demands may incur additional investments on communication facilities between the supply and the demand [20].

The rest of this paper is organized as follows. Section 2 describes the modeling of uncertainties in the proposed model. Section 3 presents the framework and the decomposition procedure applied to the model. Section 4 provides a detailed formulation of the problem and the solution methodology. Section 5 presents and discusses the case studies for a six-bus system and the IEEE 118-bus system over a 10-year planning period. The conclusions drawn from the case studies are provided in Section 6.

2. Uncertainty in power system planning

The uncertainty can be categorized into (1) the participant level uncertainty which includes fuel availability and emission costs, discount rates, investment costs, competition, etc., and (2) the ISO level uncertainty which includes random component outages and load and wind forecast errors. The financial risks are usually included in the market participant portfolio optimization [21]. As this paper assumes that the investors have already submitted their expansion planning proposals to the ISO, the participant level uncertainty is not considered. Accordingly, the ISO's uncertainty is considered in scenarios to maintain the reliability index at an acceptable level. The ISO assumes the stochastic behavior of power systems corresponding to component outages and load and wind forecast errors by deploying an optimal level of generation reserves. The embedded expansion planning risk, assumed to be undertaken by the ISO, is modeled in Section 4 by adding the cost of imaginary units to the ISO's objective function.

The Monte Carlo (MC) simulation method is adopted to simulate random characteristics of power systems. The proposed stochastic planning model would consider multiple scenarios in the Monte Carlo simulation [23,24]. To address the uncertainty of WG, we assume the wind power is subject to a Weibull distribution. The detailed modeling of WG uncertainty with a Weibull distribution is provided in Refs. [13,22]. The Monte Carlo simulation will generate a large number of scenarios considering wind speed forecast errors. In each scenario, the hourly WG is considered to be given.

To consider random outages of generators and transmission lines, we use UX and UY vectors in the Monte Carlo simulation, which $UX_{iht} = 1$ indicates that the i th generator is available in year t and scheduling period h while $UX_{iht} = 0$ indicates otherwise. Likewise, $UY_{jht} = 1$ indicates that the j th transmission line is available in year t and scheduling period h while $UY_{jht} = 0$ indicates otherwise [23].

To consider load forecast errors, the annual peak load forecast is expressed as the base load times the annual growth rate. The annual growth rate consists of an average growth rate and a random component. Normally distributed random components are assumed to be added to the average growth rates in order to reflect an uncertain economic growth or weather changes in the load forecast [24]. The hourly load at each bus is then determined based on the annual system peak load using given load distribution factors.

Each scenario is assigned a probability of occurrence, PRs, that is one divided by the number of generated scenarios. The number of scenarios has a substantial impact on the computational requirements for solving scenario-based optimization models. Therefore, using an effective scenario reduction method could be very essential for solving large-scale systems [25]. The reduction technique is a scenario-based approximation with a smaller number of scenarios and a reasonably good approximation of original system. Therefore, we determine a subset of scenarios and a probability measure based on the subset that is the closest to the initial probability distribution in terms of probability metrics. The General Algebraic Modeling System (GAMS) is used in this study. GAMS provides a tool called SCENRED for scenario reduction and modeling random data processes. These scenario reduction algorithms provided by SCENRED determine a scenario subset (of prescribed cardinality or accuracy) and assign optimal probabilities to the preserved scenarios [26].

3. Planning model description

Fig. 1 depicts the proposed planning model. The Benders decomposition is used to decompose the planning problem into the optimal investment plan as master problem, and

Fig. 1. The ISO's proposed planning framework.

the reliability and the optimal operation as two subproblems. The optimality of Benders decomposition as well as its applicability to power system problems is discussed in Refs. [27–30].

It is assumed that the level of wind integration is already known by the ISO. The large WG integration could aggravate the reliability of power systems if non-wind units cannot adequately support WG variations. The fast-response units are planned in this study to tackle such uncertainties. On the other hand, the emission associated with fast-response gas units may negatively contribute to the overall goal of WG expansion. Therefore, the proposed study would determine the optimal mix of generation which would also satisfy the system reliability.

In Fig. 1, the candidate set of fast-response generating units is provided to the ISO by market participants. Although, the ISO is not making any investment decisions, it would maintain the system reliability along with the minimum social cost (i.e., total operation and investment cost) to enhanced the market operation. The optimal investment plan of the new generating units is determined in the ISO's master problem. The objective of the master problem is to minimize the total investment cost of new generating units while considering the planning constraints. The planning constraints include capital investment funds, the maximum number of units, and the construction time of candidate units. The lower bound of the objective function is also obtained in the master problem and used further to check the optimality of the proposed plan. In addition to the planning constraints, the cuts generated in the subproblems are considered in the master problem. All binary variables are considered in the master problem and all constraints are linear. The master problem is a mixed-integer linear programming (MILP) problem. Commitment states are adjusted in the master problem through the cuts provided by reliability and optimal operation subproblems.

The reliability check subproblem examines the plan proposed by the master problem for the feasibility of system reliability constraints. This subproblem would satisfy the power balance in every bus while preserving the transmission security and physical constraints of generating units. In the case of feasibility violations, a reliability cut will be formed and added to the master problem for solving the next iteration of the planning problem. This iterative process will continue until a reliable plan is calculated. Once the system reliability is feasible, the optimal operation subproblem will consider the optimality of the proposed plan. The iterative process will continue until the given convergence criterion is satisfied.

Fig. 2. Flowchart of the ISO's proposed planning problem.

4. Formulation and solution methodology

The ISO's proposed objective of security-constrained planning is to minimize the total cost of planning (1) while satisfying the planning and the operation constraints:

$$Y = \sum_{t=1}^{NT} \sum_{i=1}^{NG} \frac{PIC_{it}(GX_{it} - GX_{i(t-1)})}{(1+d)^{(t-1)}} + \sum_{s=1}^{NS} PR_s \sum_{t=1}^{NT} \sum_{h=1}^{NH} \sum_{i=1}^{NG} \frac{DT_{ht} PO_{iht} P_{ihts}}{(1+d)^{(t-1)}} \quad (1)$$

Fig. 2 depicts the flowchart of the decomposed planning problem. The solution steps are listed as follows:

Step 1 (scenario generation): We assume that the list of fast-response thermal units is provided by the participants as an input data to the ISO. The initial information provided to the ISO includes investment candidate units of individual participants, forced outages of generating units and transmission lines, as well as load and wind speed forecast errors. A set of scenarios is created using the Monte Carlo simulation. The stochastic long-term planning problem is inherently large. So, the scenario reduction is utilized to establish a tradeoff between the execution time and the accuracy of the long-term planning solution.

Step 2 (master problem): The proposed model consists of an MILP master problem and two LP subproblems. The master problem provides the optimal investment plan, while the subproblems provide the reliability check and the optimal market operation. The optimal investment plan is determined in the master problem, where the objective is to minimize the investment cost of new fast-response generating units (2).

Min Z

$$Z \geq \sum_{t=1}^{NT} \sum_{i=1}^{NG} \frac{PIC_{it}(GX_{it} - GX_{i(t-1)})}{(1+d)^{(t-1)}} \quad (2)$$

This objective is subject to planning constraints for new units, which include the construction time (3), the installation status (4), and the commitment state of such fast-response units (5):

$$GX_{it} = 0 \text{ if } t < CT_i \quad (3)$$

$$GX_{i(t-1)} \leq GX_{it} \quad (4)$$

$$I_{iht} \leq GX_{it} \quad (5)$$

The master problem solution consists of the optimal investment plan, commitment state of new units, and the lower bound of the planning objective function. At the first iteration there are no system constraints on commitment states of the units; so random values are assigned to these variables. However, in the subsequent iterations the Benders cuts from the reliability check and the optimal operation subproblems establish the constraints on the unit states. The proper initial values for I could reduce the solution time. If an infeasibility problem occurs (i.e., no solution is found in Fig. 2), the ISO would consider preventive actions including load curtailments or the additional incentives provided to participants for extra capacity expansions.

Step 3 (reliability check subproblem): After determining the optimal plan, $G\hat{X}_{it}$, and commitment states, $\hat{I}_{iht}$, of generating units in the master problem, the reliability check subproblem will minimize the system violations based on the master solution. Slack variables are considered in the power balance constraint, where the objective (6) is to minimize these slack variables. The objective function (6) is subject to nodal power balance constraint (7), generating unit installation status (8), commitment states (9) which are determined in the master problem, generating limits (10), DC power flow (11), transmission lines limits (12), and ramping constraints (13) and (14):

$$\text{Min } W_{ts}^r = \sum_{h=1}^{NH} \sum_{b=1}^{NB} (SL_{bhts,1}^r + SL_{bhts,2}^r) \quad (6)$$

S.t.

$$P_{hbts} - \sum_{j \in J_b} PL_{jbts} + SL_{bhts,1} - SL_{bhts,2} = PD_{bhts} \quad (7)$$

$$GX_{its} = G\hat{X}_{it} \quad \lambda_{its} \quad (8)$$

$$I_{ihts} = \hat{I}_{iht} \quad \mu_{ihts} \quad (9)$$

$$P_{\min,i} I_{iht} UX_{ihts} \leq P_{ihts} \leq P_{\max,i} I_{iht} UX_{ihts} \quad (10)$$

$$PL_{jhts} - \frac{\theta_{jmhts} - \theta_{jnhts}}{x_j} = (1 - U_{jhts})M \quad (11)$$

$$|PL_{jhts}| \leq PL_{\max,j} UY_{jhts} \quad (12)$$

$$P_{ihts} - P_{i(h-1)ts} \leq [1 - I_{ihts}(1 - I_{i(h-1)ts})]RU_i + I_{ihts}(1 - I_{i(h-1)ts})P_{\min,i} \quad (13)$$

$$P_{i(h-1)ts} - P_{ihts} \leq [1 - I_{i(h-1)ts}(1 - I_{ihts})]RD_i + I_{i(h-1)ts}(1 - I_{ihts})P_{\min,i} \quad (14)$$

The stochastic planning solution would satisfy the long-term reliability index, i.e., loss of energy probability (LOEP). A Benders cut at iteration r is generated and the corresponding reliability signal is sent to the master problem when the LOEP at hour h in year t is larger than the target LOEP. LOEP is applied as a constraint to limit the amount of unsupplied hourly load. The yearly sum would satisfy the annual LOEP. However, the benefit of using the hourly index is that it would prevent any large-scale load shedding at certain hours. The LOEP at hour h in year t is calculated by dividing the expected generation deficit, $SL_{bhts,1}^r$, in (6) by the expected load at hour h in year t . The reliability constraint in (15) would also enforce generation surplus, $SL_{bhts,2}^r$, to be zero. If either constraint in (15) is not satisfied, the Benders cut (16) will be generated:

$$\begin{cases} \sum_{h=1}^{NH} \sum_{b=1}^{NB} SL_{bhts,2}^r = 0 \\ \sum_{s=1}^{NS} \left(PR_s \sum_{b=1}^{NB} SL_{bhts,1}^r \right) / \sum_{s=1}^{NS} (PR_s L_{hts}) \leq LOEP_{ht} \end{cases} \quad (15)$$

$$\begin{aligned} & \sum_{s=1}^{NS} (PR_s W_{ts}^r) + \sum_{s=1}^{NS} \sum_{i=1}^{NG} PR_s \lambda_{its} (GX_{its} - G\hat{X}_{it}) \\ & + \sum_{s=1}^{NS} \sum_{i=1}^{NG} \sum_{h=1}^{NH} PR_s \mu_{ihts} (I_{ihts} - \hat{I}_{iht}) \leq \sum_{s=1}^{NS} \sum_{h=1}^{NH} LOEP_{ht} \cdot PR_s \cdot L_{hts} \end{aligned} \quad (16)$$

The Benders cut (16) represents the coupled information on the existing unit commitment state and the candidate unit installation status. The cut indicates that the violation can be mitigated by readjusting the master's investment plan in year t .

Step 4 (optimal operation subproblem): The objective of the optimal operation subproblem is to maximize the social welfare based on submitted bids for generation and demand. The social welfare is defined as the difference between consumption payments, based on accepted bids, and production costs. Security-constrained economic dispatch (SCED) is utilized to model the optimal operation subproblem which checks the optimality of the proposed solution.

When the power demand is inelastic, the objective function is to minimize the system cost for the given investment plan and the unit commitment state (17). In some scenarios, generating unit and transmission line outages can cause solution infeasibility. To calculate the price in such cases, imaginary generating units (IMP) are assumed to supply the deficient energy at high prices as represented below. The energy supplied by the IMPs represents the expected unsupplied energy (EUE):

$$\begin{aligned} \text{Min } V_s^q = & \sum_{t=1}^{NT} \sum_{h=1}^{NH} \sum_{i=1}^{NG} \frac{DT_{ht} PO_{iht} P_{ihts}}{(1+d)^{(t-1)}} \\ & + \sum_{t=1}^{NT} \sum_{h=1}^{NH} \sum_{b=1}^{NB} \frac{DT_{ht} IMC_{bht} IMP_{bhts}}{(1+d)^{(t-1)}} \end{aligned} \quad (17)$$

S.t.

$$\sum_{i=1}^{NG} P_{ihts} + \sum_{b=1}^{NB} IMP_{bhts} = \sum_{b=1}^{NB} PD_{bhts} \quad (18)$$

$$\mathbf{A} \cdot \mathbf{P} - \mathbf{B} \cdot \mathbf{PD} + \mathbf{IMP} \leq \mathbf{K} \cdot \mathbf{PL} \quad (19)$$

$$0 \leq IMP_{bhts} \quad \forall b \quad (20)$$

The optimal operation objective is subject to physical constraints, which are similar to the reliability check subproblem (8)–(14). The solution of this subproblem provides the upper bound of the objective function in the master problem. This upper bound is used to check the optimality of the solution. If the proposed plan is not optimal, the Benders cut (21) will be formed and added to the master problem for the next iteration.

$$\begin{aligned} Z \geq & \sum_{s=1}^{NS} PR_s V_s^q + \sum_{t=1}^{NT} \sum_{i=1}^{NG} \frac{PIC_{it}(GX_{its} - GX_{i(t-1)s})}{(1+d)^{(t-1)}} \\ & + \sum_{s=1}^{NS} PR_s \sum_{t=1}^{NT} \sum_{i=1}^{NG} \lambda_{its}(GX_{its} - G\hat{X}_{it}) \\ & + \sum_{s=1}^{NS} PR_s \sum_{t=1}^{NT} \sum_{h=1}^{NH} \sum_{i=1}^{NG} \mu_{ihts}(I_{ihts} - \hat{I}_{iht}) \end{aligned} \quad (21)$$

The important feature of the Benders decomposition is the availability of upper and lower bounds to the optimal solution at each iteration. These bounds are used as an effective convergence criterion. The convergence criterion is given as

$$\frac{Y - Z}{Y + Z} < \varepsilon \quad (22)$$

where ε is a small positive number which shows the predefined threshold to accept the solution as optimal.

Table 2

Transmission line data.

Line number	From bus number	To bus number	Reactance (Ω)	Capacity (MW)
1	1	2	0.17	200
2	2	3	0.137	100
3	1	4	0.258	100
4	2	4	0.197	100
5	4	5	0.137	100
6	5	6	0.14	100
7	3	6	0.118	100

Fig. 3. Six-bus system.

Table 1

Existing generator data.

Generator	Capacity (MW)	Ramp up/down (MW/h)	Operating cost coefficient (\$/MWh)
G ₁	250	20	13.5
G ₂	100	30	22.6
G ₃	50	20	17.6

5. Numerical simulations

In this section, two case studies are presented. In Section 6.1, different aspects of centralized and distributed WG expansion are investigated.

Two case studies consisting of a six-bus system and the IEEE 118-bus system are analyzed to illustrate the performance of the proposed method. The model is implemented on a 2.4-GHz server with a 64 GB of memory with the CPLEX solver. Using the six-bus system, centralized and distributed WG expansions are discussed. The IEEE 118-bus system is selected to investigate the effect of transmission constraints on the proposed expansion planning model. This study will consider the planning of fast-response thermal generating units for a given level of WG integration.

5.1. Six-bus system

This system is shown in Fig. 3 [31]. Based on wind speed forecasts, three wind zones are defined in the system with the WG capacity factors of 47%, 39% and 32%, respectively. The capacity factor of a WG is the ratio of the actual available wind power generation over a given period (e.g., 1 year) to its output if it had operated at full nameplate capacity the entire time. A 10-year planning horizon is considered for this study. The system data are given in Tables 1 and 2. The base-case annual peak load forecast is listed in Table 3. This load is distributed with the ratio of 50%, 30% and 20% among buses 3, 4 and 5, respectively. It is assumed that the load has the same distribution factor in the

Table 3

Forecasted annual peak load of six-bus system.

Year	1	2	3	4	5	6	7	8	9	10
Peak load (MW)	256	262	269	276	283	290	297	304	312	320

Table 4

Candidate fast-response generating units in six-bus system.

Bus number	Capacity (MW)	Ramp up/down (MW/h)	Operating cost coefficient (\$/MWh)	Investment cost (k\$/MW)
1	30	30	18.3	1050
2	30	30	20.9	959
3	30	30	22.5	847
4	30	30	24.55	780.5
5	30	30	26.4	700
6	30	30	28.1	577.5

entire planning period. The annual peak load forecast is the base load (i.e., 256 MW) times the annual growth rate (i.e., 2.5% per year). The random component of the peak load and energy demand growth rate is assumed to have a normal distribution with a zero mean and standard deviation of 0.01. The hourly load distribution factor and the hourly wind generation forecast are provided in <http://motor.ece.iit.edu/data/6bus.Hourly.Data.xls>.

Table 4 shows the candidate generating unit data. The hourly cost of wind generation is negligible. The WG capacity is 120 MW which is centralized (i.e., Case 1) and distributed (Cases 2–4). Five cases are studied as follows:

Case 1: Planning with WG centered at bus 1.

Case 2: Planning with WG distributed at buses 1, 3 and 4.

Case 3: WG in Case 2 with the outage of line 5–6 in year 8.

Case 4: WG in Case 2 with the outage of unit 3 in year 8.

Case 5: WG in Case 2 with the simultaneous outages in Cases 3 and 4.

Case 1: In this case, the proposed WG capacity is aggregated at bus 1 located in zone 1 with the best wind speed pattern. In this case a 120 MW WG with a capacity factor of 47% is added in the first year of planning period at bus 1. The shortcoming of such a plan is that large wind speed variations at bus 1 may not be compensated by other generating units. The proposed method is used to find the results shown in Table 5. WG and the cheaper existing unit 1 are committed at all hours while the existing unit 2 is used at peak hours to satisfy the remaining load and minimize the operating cost. The total investment and operating costs are \$178.15M while the operating cost is \$73.75M. In this case, at the beginning, the candidate unit 1 is installed at bus 1 and the candidate unit 3 is introduced at bus 3 which is the system's largest load center. The other three candidate units in Table 5 are added in later years when the WG capacity and loads are increased. Another significant deficit of such centralized solution could be the lack of enough transmission access [32].

Case 2: We disaggregate the WG capacity in Case 1 to represent three WG units located at different zones as depicted in Fig. 3. Each WG has a capacity of 40 MW and the WG capacity factor in the two remote areas, i.e., zones 2 and 3, are less than that in zone 1 (i.e., site in Case 1). Table 6 shows the candidate unit installation year. Similar to Case 1, candidate units 2 and 3 are installed in years 5 and 1, respectively. However, the installation of candidate unit 1 at bus 1 is delayed until year 7. The average generation of WG₁ located at bus

Table 5

Candidate fast-response unit installation year: Case 1.

Unit	1	2	3	4	5	6
Year	1	5	1	5	7	–

Table 6

Candidate generating units installation year: Case 2.

Unit	1	2	3	4	5	6
Year	7	5	1	–	–	–

1 is 9 MW (i.e., 22.5% of WG₁ capacity) while there is no congestion on lines 1 and 3. The reason the low-cost WG₁ is dispatched below its capacity factor in some periods is the system ramping constraint. Therefore, after the installation of the fast-response unit in year 7, the average generation of WG₁ increases to 17 MW (i.e., 42.5% of WG₁ capacity). This amount is less than WG₁ capacity factor (i.e., 47%), which is due to transmission and operating constraints (i.e., thermal generating units min generation limit, system ramping and min on/off constraints, etc.). Compared to Case 1, the total investment and operating costs decrease to \$142.91M while the operating cost increases to \$80.07M.

In Case 2 the total WG utilization decreases by 24% as compared to Case 1, which is because of the lower capacity factor in zones 2 and 3. A lower WG utilization would result in the dispatch of more expensive thermal units and the increase in operating costs. If we could set the capacity factor of zones 2 and 3 to be the same as that in zone 1 (i.e., 47%) the operating cost would decrease to \$71.95M. Fig. 4 depicts operation and investment costs as a function of WG capacity. The initial point in Fig. 4 is associated with the current level of WG penetration. Here, the operation cost would decrease as the investment cost on fast-response generating units increases. Based on social cost results, it is concluded that the optimal increase in WG capacity is 20% (i.e., it would result in the minimum social cost).

While zones 2 and 3 have lower WG capacity factors, the dispersion of WG in the three locations would cause a significant decrease in the total cost and a more utilization of available low-cost WG. The reason for such cost reductions is that the intermittency of WG in one zone may be compensated by available WGs in the other zones. Accordingly, a smaller fast-response generation capacity would be needed for reliability purposes.

Fig. 4. System operation cost and fast-response unit investment cost vs. WG capacity.

Table 7

Candidate generating units installation year: Case 3.

Unit	1	2	3	4	5	6
Year	7	5	1	10	8	–

Table 8

Candidate generating units installation year: Case 4.

Unit	1	2	3	4	5	6
Year	7	5	1	8	–	–

Case 3: The outage of line 5–6 at the peak-load period in the year 8 is considered in this case. Similar to Case 2, the candidate generating units 3, 2 and 1 are installed in years 1, 5 and 7, respectively as shown in Table 7. In addition, as a preventive action, candidate units 5 and 4 are installed in years 8 and 10, respectively. The outage of line 5–6 decreases the transmission access between zones 2 and 3. Therefore, the addition of candidate units 4 and 5 would be necessary at zone 2. Compared to Case 2, the total cost has increased to \$163.65M.

Case 4: The outage of unit 3 in the peak-load period in the year 8 would change the plan proposed in Case 2. New generating units 3, 2 and 1 are again added in years 1, 5 and 7, respectively as shown in Table 8. In addition, the installation of candidate unit 4 in year 8 is a preventive action to compensate the possible outage of unit

Table 9

Candidate generating units installation year: Case 5.

Unit	1	2	3	4	5	6
Year	7	7	1	8	8	–

3. This preventive action increases the planning cost to \$154.94M and the operating cost to \$80.08M.

Case 5: Simultaneous outages of line 5–6 and generating unit 3 at peak and off-peak periods in the year 8 are considered respectively. Similar to previous cases, the candidate unit 1 is installed in year 1. Candidate units 4 and 5 are installed in the year 8 as shown in Table 9 to compensate the system's possible outage. The total cost increases to \$164.31M, which is the highest among all the cases, while the operating cost does not change significantly as compared to Cases 4 and 5.

5.2. IEEE 118-bus

A modified 118-bus system in Fig. 5 is used in this case. The test data and the single line diagram are provided in <http://motor.ece.iit.edu/data/IEEE118bus.data.figure.xls>. The system has 54 units, 186 branches, 14 capacitors, 9 tap-changing transformers, and 91 demand sides. The peak load of initial year is 3733 MW. The system is tested in a 10-year time horizon to

Fig. 5. One-line diagram of IEEE 118-bus system.

Table 10
WG data and network connection year.

WG	Bus number	Capacity (MW)	Wind capacity factor (%)	Network connection year
1	1	150	39	1
2	2	200	37	3
3	3	250	36	5
4	11	250	35	7
5	13	300	34	9

demonstrate the stochastic long-term planning solution. The average annual peak load growth rate is assumed to be 5%. The random component of the peak load and energy demand growth rate is assumed to have a normal distribution with a zero mean and standard deviation of 0.01. The discount rate is 10% which is used in the calculation of net present value of new generating units and the operating cost of existing units during the planning period. The convergence criterion ε is 0.1%. The planning period includes hours in which the WG variation is significant. The target LOEP is 5% at all hours. Five WGs are to be connected to the grid, which is based on the predefined schedule given in Table 10. The candidate fast-response generating unit data are presented in Table 11.

The low-discrepancy Monte Carlo simulation method is used to create 1000 scenarios, each representing possible component outages, load forecast errors, and wind speed volatilities. The computation time for the scenario-based problem depends on the number of scenarios. Therefore, using the scenario reduction method, the number of scenarios is reduced from 1000 to 10 as a tradeoff between the computation time and the solution accuracy. Table 12 shows the scenario weights after the reduction. We consider four test cases categorized into deterministic (Cases 1 and 2) and stochastic (Case 3 and 4) cases as follows.

Case 1: Transmission-constrained deterministic case.

Case 2: Deterministic case without transmission constraints.

Case 3: Transmission-constrained stochastic case.

Case 4: Stochastic case without transmission constraints.

Table 13 shows the installation year of candidate units. In Case 3, the candidate unit 5 is installed in year 5 to handle uncertainties. Compared to Case 1, the candidate generating units 2 and 9 are installed a year earlier in Case 3. Additional fast-response generating unit would have to be installed earlier in the stochastic cases (Cases 3 and 4) as compared to the deterministic cases (Cases 1 and 2). This is because of the random outages of generation units and transmission lines as well as load and wind forecast errors.

Table 14 shows the planning and operating costs in four cases. The costs in Case 3 are higher than those in Case 1 by \$43.287M and \$2.871M, respectively. The costs are higher when uncertainties are considered as additional generating units and transmission lines would be installed. The operating and planning costs could

Table 12
Weight of each scenario after scenario reduction (%).

Scenario	1	2	3	4	5	6	7	8	9	10
Weight	5.3	0.1	0.1	0.1	61.2	3.9	4.4	0.1	5.0	19.8

Table 13
Candidate unit installation year.

Unit number	1	2	3	4	5	6	7	8	9	10
Case 1	8	8	9	–	–	1	1	1	7	8
Case 2	–	–	–	–	–	1	1	6	–	–
Case 3	8	7	9	–	5	1	1	1	6	8
Case 4	–	–	–	–	5	1	1	6	–	–

Table 14
Total planning and operating costs.

Case	Planning cost (billion\$)	Operating cost (billion\$)
Case 1	2.149	1.516
Case 2	1.834	1.489
Case 3	2.192	1.518
Case 4	1.877	1.490

Table 15
Computation time for one scenario in each iteration.

Convergence criterion value (%)	Computation time for one scenario (h)
0.001	5.41
0.01	5.29
0.05	5.21
0.1	4.93
10	4.57

be decreased when transmission constraints are relaxed (Cases 2 and 4). Here, the system can handle more WG variations if a sufficient transmission access is available. Therefore, a coordinated generation-transmission planning would be necessary for a high integration of WG.

The CPU time is about 5 h for one scenario in Case 3 (i.e., the most computationally intensive case). Table 15 lists the computation time for different convergence criteria. With the possible short-cuts introduced in Section 6, the CPU time could be further reduced to less than 2 h.

6. Discussions and conclusions

A stochastic planning method is proposed for the fast-response generating units in power systems with large WG integrations. In this paper, we assume that market participants would individually submit their candidate list of units to the ISO. It is the responsibility of the ISO to determine which candidates would violate the system reliability by considering the power system constraints. In this

Table 11
Candidate fast-response generating units in 118-bus system.

Unit number	Bus number	Capacity (MW)	Ramp up/down (MW/h)	Operating cost coefficient (\$/MWh)	Investment cost (Thousand \$/MW)
1	35	100	100	17.5	1050
2	41	100	100	18	945
3	45	100	100	18.5	840
4	60	100	100	19.5	735
5	75	100	100	20	630
6	94	150	150	13.5	945
7	95	150	150	14.5	875
8	96	150	150	15.5	770
9	98	150	150	16	665
10	118	150	150	16.5	595

paper, the ISO does not make any investments. Rather it maintains the reliability of the system. Although, the proposed expansion model is for fast-response units, the same approach can be utilized for the capacity expansion planning of any kind of generating units or transmission lines. The Monte Carlo simulation and the scenario reduction techniques are applied for representing the random outages of generating units and transmission lines, and load and wind speed forecast errors. Scenarios would add a dimension to the planning problem that could make the large-scale expansion planning problem more complex and computationally impractical. Hence, the Benders decomposition is utilized for the decomposition of the problem into tractable easy-to-solve subproblems at each period.

The numerical experiments show that the fast-response units can improve the reliability of power systems in the case of large integration of volatile WG. The merits of proposed stochastic approach include the provision of reliable decision signals to planners and regulators on the long-term capacity expansion planning. It is also observed that the transmission access has a significant impact on the generation expansion especially when there is a large wind integration. The results show that a coordinated generation-transmission planning can significantly improve the WG integration.

A few short-cuts are introduced to speed up the solution. These short-cuts are listed as follows:

- Limit the hours under study: power systems may not face large wind variations on the hourly basis. Wind variations at many hours may also be compensated by the existing generation redispatch. So, we could select certain hours for analyses at which the incremental wind generation in two subsequent hours is larger than a percentage of the generation at the given hours. To ensure the capacity adequacy, the peak load hours are always added to the study.
- Limit the committable units: generating units may be classified as always ON, always OFF and committable units [33]. Intrinsically, peak loads will utilize Always OFF units and base loads utilize Always ON units. We determine the status of committable units by iterations between the master and the subproblems.

Appendix A. List of symbols

b	index of bus
t	index of planning year
h	index of subperiod
i	index of generating unit
j	index of transmission line
s	index of scenario
r, q	index of iteration number

Parameters and variables

CT_i	construction time of candidate unit i
d	discount rate
DT_{ht}	duration of subperiod h in year t , e.g., 1 h
Gx_{its}	installation status of generating unit i in year t and scenario s , 1 if installed, otherwise 0
I_{ihts}	commitment state of generating unit i in subperiod h of year t in scenario s , 1 means on and 0 means off
j_b	preserved set of branches connected to bus b
IMP_{bhts}	dispatched capacity of imaginary unit at bus b in subperiod h of year t in scenario s
IMC_{bht}	cost of imaginary unit at bus b in subperiod h of year t
L_{hts}	load in subperiod h of year t in scenario s
LOEP	target LOEP, reliability criterion
NB	number of buses

NT	number of years
NG	number of generating units
NH	number of subperiods
NS	number of scenarios
PIC_{it}	investment cost of unit i at year t
PD_{bhts}	load at bus b in subperiod h at year t in scenario s
PR_s	probability of scenario s
PL_{jhts}	real power flow of transmission line j in subperiod h of year t in scenario s
P_{ihts}	generation dispatch of unit i in subperiod h of year t in scenario s
PO_i	operating cost of generating unit i
RU_i, RD_i	ramping up/down limit of unit i
SL^r_{bhts}	slack variable for bus b in subperiod h of year t in scenario s
UY_{jhts}	transmission lines availability status of transmission line j subperiod h of year t in scenario s , 0 if in outage, otherwise 1
UX_{ihts}	generators availability status of unit i in subperiod h of year t in scenario s , 0 if in outage, otherwise 1

Matrices and vectors

A	bus-unit incidence matrix
B	bus-load incidence matrix
IMP	dispatched capacity of imaginary unit vector
K	bus-branch incidence matrix
P	real power output vector
PD	load vector

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Generation expansion planning in wind-thermal power systems

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Abstract: The intermittency and volatility of wind generation (WG) would require additional upward and downward reserves, as well as enhanced ramping capabilities in power systems. This study investigates the optimal expansion planning of fast-response generating capacity (e.g. gas-fired units) to accommodate the uncertainty of WG. The study utilises a mixed integer programming-based security-constrained unit commitment for analysing operational and reliability issues related to the proposed optimisation problem. Numerical experiments signify the effectiveness of the proposed method.

Nomenclature

The symbols used in this paper are classified into indices, parameters and variables as follows.

Indexes

t	index of planning time
i	index of thermal unit
g	index of gas-fired unit
w	index of wind generator (WG)
cm	index of compressor
s	index of scenario

Parameters and variables

PO	operation cost of generating unit
PIC	investment cost
NT	number of times under study
NI	number of thermal generation units
NG	number of gas-fired units
NW	number of WGs
NS	number of scenarios
I	unit commitment schedule vector
$F_i(\cdot)$	fuel cost function of thermal generation unit
$F_g(\cdot)$	operating cost function of gas-fired units

$F_w(\cdot)$	operating cost function of WG
P	generation dispatch of a unit
GX_g	installation status of candidate gas-fired unit g , 1 if installed, otherwise 0
wf	weighting factor (represents energy not served cost a percentage of social cost)
CENS	cost of energy not served
a, b, c	coefficients of thermal unit cost function
ga, gb, gc	gas consumption coefficients of compressor
gc	cost of natural gas contract
C_{cm}	cost of natural gas consumption of a compressor
HP	horsepower of compressor
ρ_{gas}	price of natural gas
f_{gas}	natural gas consumption of gas-fired unit
LS	amount of scheduled load shedding
EENS	expected energy not served
VOLL	value of lost load
$PR(Z_s)$	individual probability of forced outage of Z_s (MW)
Z_s	load shedding in the s th contingency scenario
EC_s	energy curtailed due to forced outage of Z_s MW
D	power system demand
GL	total generation capacity of power system
USR,	system up/down spinning reserve requirement
DSR	without the WG uncertainty

ASR_U, ASR_D	coefficients of up/down spinning reserve due to the WG uncertainty
US_{it}, DS_{it}	up/down spinning reserve of unit i at time t
RU_i, RD_i	ramp up/down limit of unit i
$d\%$	percentage of unit capacity available for reserve
MSR	maximum sustained ramp rate (MW/min)
$X_{it}^{on}, X_{it}^{off}$	period that unit i has been on/off at time t
T_i^{on}, T_i^{off}	minimum up/down time of unit i
κ, η	Weibull's probability distribution function shape and scale parameter
v, v_{CI}, v_{CO}, v_R	instantaneous, cut-in, cut-out and rated wind speed
P_w^*	available WG power
PW	system's total WG
SRC	system total ramping capability
SRCD	system ramp down capability without gas-fired unit contribution
SRCU	system ramp up capability without gas-fired unit contribution

1 Introduction

Wind generation (WG) emerges with new challenges in power systems. In practice, WG large forecasting errors are not uncommon [1, 2]. Therefore the volatile nature of WG would require a more sophisticated approach to the planning and operation of power systems [3, 4]. During the last decade, the capital cost of WG has substantially decreased, which has made WG a serious contender among generation resources [5, 6]. The environmental concerns have also persuaded governments to impose additional restrictions such as production tax credit (PTC) on carbon production and enhanced standards and initiatives such as renewable portfolio standard (RPS) and regional greenhouse gas initiative (RGGI) for expanding renewable energy generation [7].

The intermittent nature of WG would create a planning challenge for calculating the optimal size of reserve and generation ramping that could guarantee a reliable supply of load. The WG penetration could result in power system vulnerabilities, if ancillary services are not scheduled properly [3, 4]. The additional reserves must also be co-ordinated with ramping requirements in order to respond to WG interruptions quickly. Temporary solutions like the utilisation of storage systems or additional power exchanges with adjacent power systems have been considered. However, the most effective solution for responding to the volatility and intermittency of WG is the use of fast-response conventional generation systems for compensating the WG shortcomings [8].

Several publications have addressed the WG integration in power systems. The impact of large-scale WG on the scheduling of conventional generation is investigated when considering the operation cost and reliability of the system [8]. The impact of wind forecasting errors on power system operations is discussed in [1] by applying different unit commitment models. In [9] by applying the Monte-Carlo simulation, a security-constrained unit commitment algorithm has been developed that takes into account the intermittency and variability of wind power generation. An economic dispatch model was developed in [10] by applying genetic algorithm. The incorporation of wind energy conversion system in power system unit commitment and economic dispatch was discussed in [11]. A co-ordinated wind-thermal dispatch using direct search method was presented in [12]. A combination of branch and bound and dynamic programming algorithms was developed in [13] to model the co-ordinated economic dispatch of wind and thermal generation in isolated power systems. The impact of transmission capacity on the WG expansion was discussed in [14], which considered additional zonal reserves for an uncertain WG. The adequacy of power systems with WG was evaluated in [15]. A few articles investigated the utilisation of demand response for the reliability enhancement when considering the WG uncertainty [16–18]. The main problem with such approaches is that the amount of interruptible load is usually small as compared with drastic WG changes. However, very few articles considered power system operation issues in the WG expansion planning.

This paper presents a co-ordinated wind-thermal planning framework for managing hourly WG operation issues. We utilise fast-response generating units to respond to the unpredictability of WG. The quick-start and high ramping capability of fast-response generating units allows units to reach a maximum capacity in a short time. This is a NP-complete non-convex large-scale mixed-integer optimisation problem [19]. A mixed-integer linear programming (MILP) algorithm is utilised which presents attractive features, including short convergence time, simplicity of algorithm, linearity of constraints and ability to handle large-scale problems. In our proposed stochastic resource planning problem, each possible system state is represented by a scenario. The consideration of power system component outages and the WG volatility along with the load forecast uncertainty could result in a large number of scenarios. The number of scenarios would have a substantial impact on computational requirements. So, we determine a subset of scenarios and a probability measure based on this subset that is the closest to the initial probability distribution in terms of probability metrics.

The rest of this paper is organised as follows. Section 2 briefly introduces mathematical model of wind generators. Section 3 presents problem formulation and the objective function. Incorporation of WG in optimal scheduling model with the prevailing constraints is provided in Section 4. Stochastic planning is discussed in Section 5. Section 6

presents a numerical experiments and results. Lastly, in Section 7, the conclusions drawn from the studies are provided.

2 Mathematical model of wind generators

The wind speed distribution is modelled by the Weibull probability distribution function (PDF) [20–22] as

$$f(v) = \frac{\kappa}{\lambda} \left(\frac{v}{\lambda}\right)^{\kappa-1} \cdot \exp\left[-\left(\frac{v}{\lambda}\right)^{\kappa}\right] \quad (\kappa > 0, v > 0, \lambda > 0) \quad (1)$$

We assume the WG volatility is subject to a Weibull PDF, that is, $f(v)$, where k is the shape factor based on historical data and λ is the scale factor which represents the forecasted WG.

Various methods for estimating Weibull's parameters are discussed in [23–25]. The power output of a wind turbine [26, 27] is given as

$$P_{wt}^* = \begin{cases} P_w^{\max} \frac{v^{\kappa} - v_{CI}^{\kappa}}{v_R^{\kappa} - v_{CI}^{\kappa}} & (v_{CI} \leq v \leq v_R) \\ P_w^{\max} & (v_R \leq v \leq v_{CO}) \\ 0 & (v < v_{CI} \text{ and } v > v_{CO}) \end{cases} \quad (2)$$

There is a small cost associated with WG operations. The market price of WG is determined based on bilateral contracts or locational marginal prices. Upper and lower WG are constrained by the physical characteristics of WG units as well as the optimal operation of power systems.

3 Mathematical formulation

The power system's objective (3) is to minimise the social cost (operating cost of existing generation units plus investment costs of new gas-fired units for catering to WG uncertainty). This objective is subject to unit and system constraints, including new unit installation status and commitment states (6) and (7), thermal and gas-fired unit cost function (8) and (9), fuel and compressor costs in gas-fired units (10) and (11), contingency condition (12)–(16), system constraints (17)–(19), generating unit physical constraints (20)–(29), WG constraints (30)–(33) and system ramping capability (34)–(36). The planned WG capacity is assumed to be known based on a given criterion such as the RPS plan.

3.1 Objective function

$$\text{Min PO} + \text{PIC} \quad (3)$$

such that

$$\text{PO} = \sum_{s=1}^{NS} \sum_{t=1}^{NT} \left\{ \sum_{i=1}^{NI} [F_i(P_{its})I_{its}] + \sum_{g=1}^{NG} [F_g(P_{gts})I_{gts}] + \sum_{w=1}^{NW} [F_w(P_{wts})] + wf \times \text{CENS}_{ts} \right\} \quad (4)$$

$$\text{PIC} = \sum_{g=1}^{NG} IC_g P_{\max,g} GX_{gt} \quad (5)$$

$$GX_{g(t-1)} \leq GX_{gt} \quad (6)$$

$$I_{gts} \leq GX_{gt} \quad (7)$$

$$F_i(P_{it}) = a_i + b_i P_{its} + c_i P_{its}^2 \quad (8)$$

$$F_g(P_{gts}) = gc_{ts} + C_{cm,ts} \quad (9)$$

$$gc_{ts} = \rho_{gas,t} f_{gas,gts} \quad (10)$$

$$C_{cm,ts} = ga + gbHP_{cm,s} + gcHP_{cm,s}^2 \quad (11)$$

$$\text{CENS}_{ts} = \text{EENS}_{ts} \times \text{VOLL} \quad (12)$$

$$\text{EENS}_t \leq \text{EENS}^{\max} \quad (13)$$

$$\text{EENS}_t = \sum_s (\text{PR}(Z_{ts}) \text{EC}_{ts}) \quad (14)$$

$$\text{EC}_{ts} = \begin{cases} D_t - (GL_{ts} - Z_{ts}), & \text{when } D_{ts} > GL_{ts} - Z_{ts} \\ 0, & \text{otherwise} \end{cases} \quad (15)$$

$$GL_{ts} = \sum_{i=1}^{NI} P_{its}^{\max} + \sum_{g=1}^{NG} P_{gts}^{\max} + \sum_{w=1}^{NW} P_{wts}^{\max} \quad (16)$$

3.2 Power system constraints ($\forall t = 1, \dots, DT$)

3.2.1 Power balance constraint

$$\sum_{i=1}^{NI} P_{its} I_{its} + \sum_{g=1}^{NG} P_{gts} I_{gts} + \sum_{w=1}^{NW} P_{wts} = D_{ts} \quad (17)$$

Load shedding could be considered in the case of contingencies.

3.2.2 System up/down spinning reserve requirements:

$$\sum_{i=1}^{NI} \text{US}_{its} I_{its} + \sum_{g=1}^{NG} \text{US}_{gts} GX_{gt} \geq \text{USR}_t + \text{ASR}_U \left(\sum_{w=1}^{NW} P_{wts} \right) \quad (18)$$

$$\begin{aligned} \sum_{i=1}^{NI} \text{DS}_{its} I_{its} + \sum_{g=1}^{NG} \text{DS}_{gts} I_{gts} \\ \geq \text{DSR}_t + \text{ASR}_D \left(\sum_{w=1}^{NW} P_{wts}^{\max} - \sum_{w=1}^{NW} P_{wts} \right) \end{aligned} \quad (19)$$

Equations (18) and (19) indicate that the system would require hourly up/down spinning reserves for responding to WG uncertainties. Extra reserve requirements are in proportion

to estimated hourly WGs, which are represented by ASR_U and ASR_D factors. Fast-response gas-fired generation units can enhance the system's up/down reserve requirements as discussed here. Theoretically, if the number of scenarios be large enough, then the reserve requirement can be neglected, that is, the reserve parameters (USR , DSR , ASR_U and ASR_D) would take smaller values. However, in practice there is always a trade-off between accuracy and speed. Therefore here we considered a combination of scenario-based and regulatory reserve constrained models.

3.3 Thermal and gas-fired generating unit constraints

3.3.1 Generation capacity limit

$$P_i^{\min} I_{its} \leq P_{its} \leq P_i^{\max} I_{its} \quad (20)$$

$$0 \leq P_{gts} \leq P_g^{\max} I_{gts} \quad (21)$$

3.3.2 Up/down 10-min spinning reserve contribution

$$US_{its} = \text{Min}\{d\% \times P_i^{\max}, 10 \times MSR_i, P_i^{\max} - P_{its}\} \quad (22)$$

$$DS_{its} = \text{Min}\{d\% \times P_i^{\max}, 10 \times MSR_i, P_{its} - P_i^{\min}\} \quad (23)$$

3.3.3 Ramping up/down constraints

$$P_{its} - P_{i(t-1)s} \leq [1 - I_{its} \times (1 - I_{i(t-1)s})]RU_{its} + I_{its}(1 - I_{i(t-1)s})P_i^{\min} \quad (24)$$

In (24) and (26), the assumption is that the thermal units can start-up/shutdown only at their minimum generation limit.

$$RU_{its} = \text{Min}\{RU_i, P_i^{\max} - P_{its}\} \quad (25)$$

$$P_{i(t-1)s} - P_{its} \leq [1 - I_{i(t-1)s} \times (1 - I_{its})]RD_{its} + I_{i(t-1)s}(1 - I_{its})P_i^{\min} \quad (26)$$

$$RD_{its} = \text{Min}\{RD_i, P_{its} - P_i^{\min}\} \quad (27)$$

3.3.4 Minimum up/down time constraints

$$(X_{i(t-1)s}^{\text{on}} - T_i^{\text{on}}) \times (I_{i(t-1)s} - I_{its}) \geq 0 \quad (28)$$

$$(X_{i(t-1)s}^{\text{off}} - T_i^{\text{off}}) \times (I_{its} - I_{i(t-1)s}) \geq 0 \quad (29)$$

4 Wind generator constraints

WGs incur additional constraints to optimal scheduling problem. Three constraints could limit the available WG as follows:

1. Wind velocity (2)
2. System spinning reserve (32)
3. System maximum ramping capability (33)

$$0 \leq P_{wts} \leq P_{wts}^* \quad (30)$$

$$PW_{ts} = \sum_{w=1}^{NW} P_{wts} \quad (31)$$

Using (18) and (31), the system up-spinning reserve limit is linked with the maximum available WG as

$$PW_{ts} \leq \frac{\sum_{i=1}^{NI} (US_{its} I_{its}) + \sum_{g=1}^{NG} US_{gts} GX_{gt} - USR_t}{ASR_U} \quad (32)$$

The hourly system ramping capability is linked to the hourly change in the WG output as

$$|PW_{ts} - PW_{(t-1)s}| \leq SRC_{ts} \quad (33)$$

where (see (34))

and

$$SRCD_{ts} = \sum_{i=1}^{NI} [\text{Min}(60 \times RD_i, P_{i(t-1)s} - P_i^{\min})] \quad (35)$$

$$SRCU_{ts} = \sum_{i=1}^{NI} [\text{Min}(60 \times RU_i, P_i^{\max} - P_{i(t-1)s})] \quad (36)$$

Here $\sum P_{gs}$ is the total planning candidate gas-fired generation. GX_{gt} is the decision variable for the required gas-fired generation to compensate WG deficiencies. Equation (35) forms a non-linear constraint. Therefore to keep the problem in linear conditions, this constraint is linearised by using auxiliary binary variables discussed in Section 10.1 (Appendix). The problem in (4)–(36) in addition to DC network security constraints provided in [28] is solved at all scenarios as explained in the following section.

$$SRC_{ts} = \begin{cases} SRC_{ts} + \sum_{g=1}^{NG} P_g GX_{gt}, & \text{if } PW_{ts} \geq PW_{(t-1)s} \\ SRCU_{ts} + \sum_{g=1}^{NG} (P_g^{\max} - P_g) GX_{gt}, & \text{if } PW_{ts} \leq PW_{(t-1)s} \end{cases} \quad (34)$$

5 Stochastic planning solution

The Monte-Carlo simulation along with a scenario reduction technique is applied to generate scenarios that simulate random characteristics of system components. The stochastic model is proposed which considers outages of generator and transmission system components as well as the uncertainty of load and available wind forecasts in the proposed scenarios. A set of possible scenarios is considered for modelling the uncertainties in the long-term planning problem. We assign a weight, PRs, to each scenario that would reflect the probability of the occurrence of the scenario. The WG planning would form a large-scale problem when considering operating constraints. Hence the Monte-Carlo simulation method is well-suited for such an application because the number of samples for a given accuracy level is independent of system size. A detailed formulation of Monte-Carlo approach for creating scenarios in power system operation with uncertainties can be found in [29, 30].

To address the volatility of WG, we assume the wind power is subject to a Weibull distribution, that is, $W(k, \lambda)$ where k is the shape factor achieved from historical data and λ is the scale factor which represents the forecasted WG. The Monte-Carlo simulation will generate a large number of scenarios subject to a Weibull distribution. A probability is assigned to each scenario, that is, one divided by the number of generated scenarios. In each scenario, an hourly random wind power generation is considered which is based on the forecasted wind power generation.

The simulation of power system component outages, volatility of WG and uncertainty of load forecast would result in a large number of scenarios. On the other hand, the large number of scenarios would have a substantial impact on the computational requirements of the scenario-based optimisation model. Therefore using an effective scenario reduction method would be very essential for large-scale systems [29]. The reduction technique would present a scenario-based approximation with a smaller number of scenarios for a reasonably good representation of the original system. So, we determine a subset of scenarios and a probability measure based on the subset that is the closest to the initial probability distribution in terms of probability metrics. A general algebraic modelling system (GAMS) is used in this study. GAMS provides a tool called SCENRED for scenario reduction. The scenario reduction algorithm provided by SCENRED determines a scenario subset (of prescribed cardinality or accuracy) and assigns optimal probabilities to the preserved scenarios [31].

Table 1 Weight of each scenario after scenario reduction

Scenario	1	2	3	4	5	6	7	8	9	10
Weight, %	5.1	0.1	0.1	0.1	61.2	4.1	6.9	0.1	4.8	17.5

6 Numerical results

In this section, two case studies are presented. In Section 6.1, different aspects of centralised and distributed expansion of WG are discussed. The purpose is to investigate the planning of fast-response gas-fired generation units to compensate WG uncertainties. In this paper, we assumed that market participants (e.g. GENCOs) already expressed their willingness to install new generation units by submitting the proposals to the ISO. Therefore ISO's role is to accept the proposals which benefit the system the most. In Section 6.2, a six-bus test system is selected to investigate the effect of network constraints on the proposed hybrid expansion planning. The spinning reserve parameters are $ASR_U = 20\%$, $ASR_D = 50\%$, $wf = 1$ and $VOLL = 1000$ \$/MWh. The WG parameters are $v_{CI} = 5$, $v_R = 15$ and $v_{CO} = 45$ m/s and the Weibull wind speed PDF is assumed to have $k = 2$ and $\lambda = 20$. Wind farms are assumed to operate with a negligible cost. In the following numerical experiments, the effect of gas transmission network is not considered. However, when the penetration of gas-fired units increases in the system, the impact of gas transmission network could be significant. This is the subject of our future research. The problem is coded in the GAMS with CPLEX 11.0 solver on a 2.4 GHz server computer with 64 GB memory.

6.1 Centralised and distributed wind models

The study period is one year with hourly simulations. The base-case load profile and the system data are given in Section 10.2 (Appendix). USR is assumed to be 10% of the load. The computation time for the scenario-based problem depends on the number of scenarios. The scenario reduction method would reduce the total number of scenarios from 100 to 10 as a trade-off between the solution speed and accuracy. Table 1 shows the weights of each scenario after reduction. The WG in power systems is simulated in four possible modes as follows.

6.1.1 Centralised planning: Wind unit only planning: WG expansion is concentrated in a limited area. The WG intermittency could result in higher load shedding if system reserves/ramping cannot accommodate large changes in WG. The other shortcoming of centralised investment could be the lack of large access to transmission capacity [32], which is beyond the scope of this discussion. Table 2 shows the simulation results for three different wind patterns in the zone without the addition of any gas-fired units. In this case, the installed wind capacity is 90 MW and the total thermal generation is 525 MW.

Table 2 Centralised WG without gas-fired generation expansion

Capacity factor, %	Social cost, M\$/year	
	With load shedding	Without load shedding
39	46.81	infeasible
45	45.85	infeasible
55	44.4	44.4

The capacity factor of a WG is the ratio of the actual power generation over a given period to its output if it had operated at full nameplate capacity the entire time. In Table 2, when the WG capacity factor is not large enough the solution is infeasible because the gas-fired generation capacity is not increased accordingly. This is because the existing generation units cannot provide the required spinning reserve or the system ramping capability is not sufficient to accommodate the WG fluctuations. However, a higher WG capacity factor would offer a more robust power system. If the load shedding is allowed, a feasible solution is possible at higher operating costs.

Combined wind and gas-fired unit planning: To maintain a secure operation, the combined wind-thermal planning is investigated in a centralised case. The capacity factor of WG is 39%. In this case, there is an option of installing new gas-fired units to prevent emergency load shedding. One of the major challenges would be determining the optimal reserve and its associated gas-fired unit capacity. Fast-response units provide large ramping rates which enhance the SRC along with the available 10-min spinning reserve. On the other hand, the cost of these units is usually high (e.g. annualised investment cost of \$100 k/MW is assumed). The stochastic solution provides a total objective value of \$51.95 M/year. The social cost is higher than that of the previous case when the cost of gas-fired capacity expansion is considered. However, this extra cost would benefit the social welfare by not enforcing the service curtailment to the consumers. The gas-fired unit is installed on 24th June, which is the beginning of hot season with higher hourly demands. Furthermore, the WG output would experience more fluctuations in the summer months, that is, wind speed is smaller and there would be high possibility that the WG output falls to zero ($v < v_{CI}$).

6.1.2 Dispersed planning: *Wind unit only planning:* WG farms located in a limited geographical area could increase the risk of power shortages at certain periods when the wind is not available. On the other hand, WG farms dispersed at several zones may impose additional financial risks if some of those locations possess a low quality wind. In such cases, local authorities may provide additional incentives to investors, such as easier transmission access or faster grid connection time, to encourage the dispersion of

wind farms. Indeed, the diverged planning option would result in higher system reliability if the wind is more readily available at individual zones. Assume that there are three wind farms in separate zones, each with a capacity of 30 MW (total wind capacity is the same as that in the centralised case, see Section 6.1.1) and WG capacity factor in the two remote zones are 37 and 36% which are less than that in the local site (39%).

Fig. 1 depicts the average WG variation in a 24-hour period of the operation in aforementioned three zones. Comparing with the case in Section 6.1.1 (Wind unit only planning), someone would learn that wind shortages in one zone could be covered by those in other zones (e.g. in Fig. 1 wind speed is low at hour 11 in zone 1, whereas it is higher in zones 2 and 3). Therefore the probability of large WG deficits is reduced. The study results show that the social cost is \$47.06 M/year and no gas-fired capacity expansion is needed. Despite the fact that the total capacity factor in remote zones are less than 39% (as was in the centralised zone), the cost decreases as compared to that in the centralised case. Therefore not only the WG capacity factor is an important factor in locating new wind farms, but also distance to the existing ones can significantly affect system reliability.

In another study, the available generation capacity is on outage by 20% and load shedding is considered at the cost of 1000 \$/MWh. Here, the available thermal and WG capacity is higher than the peak-load of 503.42 MW and the social cost is \$117.14M. This is because the available WG is significantly less than its rated value in most periods. The fast-response gas-fired generation is considered next.

Combined wind and gas-fired unit planning: As discussed in Section 6.1.2 (Wind unit only planning), when WG farms are dispersed geographically, the optimal solution may not require any gas-fired capacity expansions. However, the expansion of fast-response gas-fired units will provide spinning reserves and ramping requirements when considering the existing thermal unit outages. Table 3 shows the results of existing generation capacity outages. In Table 3, the larger rate of capacity outage would result

Figure 1 24-hour average WG in three zones

Table 3 Changes in social costs when resources are on outage

Capacity outage	Gas-fired installation period, hours/month	Social cost, M\$
thermal by 20%	212/January	57.35
thermal by 10%	4096/May	52.66
thermal by 5%	4910/July	51.69

Figure 2 Six-bus system single diagram**Table 4** WGs expansion plan in six-bus test case system

Bus number	WG capacity, MW	Grid connection time, year	Wind zone	Wind zone capacity factor, %
1	80	1	1	45
4	60	3	2	40
3	40	5	3	35

in the earlier generation capacity expansion as well as higher social costs.

The wind speed pattern has a substantial impact on fast-response generation expansion. The generation capacity

Table 6 Weights of each scenario after scenario reduction

Scenario	1	2	3	4	5	6
Weight	0.05	0.08	0.23	0.04	0.06	0.24
Scenario	7	8	9	10	11	12
Weight	0.05	0.045	0.045	0.015	0.045	0.1

expansion needs to be enhanced when the WG capacity factor is less than expectation. If we decrease the capacity factor in the three zones to 30, 28 and 27%, respectively, generation expansion will occur at hour 4913 while the social cost increase to \$53.05M.

6.2 Six-bus test case

This case demonstrates the effectiveness of the proposed approach for solving the optimal planning problem in a transmission-constrained power system. The optimal capacity of gas-fired generation units associated with the WG uncertainty is investigated. In addition, the impact of WG expansion on power system operation is studied. The system is shown in Fig. 2 [33] and the system data are provided in Section 10.3 (Appendix). The planning period is five years and WGs come into service at the beginning of each planning year according to the plan given in Table 4. The maximum load is 505 MW and the average load is 300 MW in the initial year of study, which is increased 5% annually in the base-case scenario. The candidate gas-fired generating units are given in Table 5. The scenario weights after reduction are shown in Table 6.

6.2.1 Fast-response generating units

requirement: Table 7 summarises the generating unit installation schedule in the planning period. The earliest installed fast-response unit is unit 4. This unit shows a balance of investment and operating costs. Furthermore, this generation unit is located at load bus 4 where WG 2 is installed in year 4. However, with an increase in WG penetration and transmission capacity limitations, extra fast-response units are installed in the last planning year. The candidate generation unit 6 is installed at bus 6

Table 5 Candidate fast-response gas-fired generation units

Bus number	Capacity, MW	Investment cost, k\$/MW/year	Operating cost, k\$/MWh	MSR, MW/min	Ramp up/down, MW/h	d%
1	50	65	15	8	100	80
2	50	60	18	8	100	80
3	50	55	18	8	100	80
4	50	50	21	8	100	80
5	50	45	23	8	100	80
6	50	40	24	8	100	80

Table 7 Generating units installation time

Unit	1	2	3	4	5	6
Hour (year/month)	40 357 (5/August)	—	39 974 (5/July)	31 213 (4/July)	—	39 973 (5/July)

in the summer of year 5. At the same time, candidate unit 3 is added to the load bus 3. In addition, candidate unit 1 is installed at bus 1 where the largest WG is located. The major reason for adding this gas-fired unit at a later period, while it has the lowest operating cost, is that the bus 1 in zone 1 has a favourable wind speed, which would reduce the necessity of adding fast-response unit.

6.2.2 Sensitivity analysis of spinning reserve and social cost: In Table 7, the fast-response units are installed to compensate the WG uncertainty which would increase the required spinning reserve capacity. The experiments demonstrate changes in system parameters as a result of WG capacity expansion. Fig. 3 depicts variations in average up/down spinning reserve requirements when WG penetration increases. Here the base case (Section 6.2.1) represents zero percent wind capacity increase. ASR_D is assumed to be larger than ASR_U , so the down spinning reserve is more influenced by the WG penetration. Hence, the down spinning reserve variation curve has a larger gradient as compared to that of the up-spinning reserve.

Increase in WG penetration would change reserve requirements and consequently affects generation scheduling. Different approaches used in literatures aimed to obtain optimal reserve requirements [34–36]. However, determining optimal amount of reserve requirements which consider

Figure 3 Average Up/down spinning reserve by increasing the WG capacity

security and economy of the system is still an open question. This deserves to be the subject of a separate paper, especially when there is large wind power penetration in the system. Based on the proposed approach, the amount of reserve requirement is directly influenced by ASR_U and ASR_D parameters. Therefore finding optimal values of these parameters would be essential. Fig. 4 depicts variation of the production, energy not served (ENS) and total operating (OP) costs when reserve parameter change. As the study shows, the minimum operating cost is obtained when $ASR_U = 1.1$ (i.e. roughly 5.5 times the wind to thermal installed capacity ratio). In the similar study, minimum OP is obtained when $ASR_D = 2$ (i.e. roughly 10 times the wind to thermal installed capacity ratio). However, the value of these parameters may change in different systems and with various wind speed pattern.

Figure 4 The effect of the variation of reserve parameter on system costs

- a Production
- b ENS
- c Total operation costs variation for change of ASR_U

Figure 5 WG variation by increasing the WG capacity

Figure 6 Cost variations by increasing the WG capacity

Fig. 5 shows the WG (MWh) addition as a result of the WG capacity (MW) expansion. However, the WG gradient decreases gradually since the system reserve and ramping capability would constrain WG. On the other hand, system may not have the capability (reserve, ramping etc.) of absorbing the whole available WG when the wind penetration is significant. Hence, fast-response units are installed when WG capacity increases by 40%. However, WG cannot increase further when the WG capacity is increased beyond 80% which is due to transmission constraints.

In Fig. 6, operation costs decrease by increasing the WG capacity. On the other hand, fast-response units are installed at additional costs to compensate the WG uncertainty. Therefore the optimal social cost provides planners with a trade-off for the optimal WG capacity expansion. In this case, the minimum social cost is \$282.72M which is achieved when the WG capacity increases by 60%.

7 Conclusions

A stochastic model for long-term generation scheduling problem is proposed in this paper. Scenario-based approach along with modified reserve and ramping constraints are modelled considering trade-off between accuracy and calculation time. Fast-response generating unit expansion is considered to alleviate WG uncertainty impacts on system reliability.

In many countries, the expansion planning of renewable energy resources is usually based on pre-scheduled or regulatory plans. We assume the WG expansion plan is given, and utilise gas-fired units as candidates to cater to the volatility and intermittency of WGs. The proposed long-term scheduling considers operating issues (e.g. system reserves and ramping of thermal units) for enhancing the system reliability. The fast-response units are costly and may contribute to emission. The optimal size and type of these units are determined in the proposed approach. Case studies showed the effectiveness of the proposed model and the effects of system component outages and load and WG uncertainties on generation capacity expansion plans and costs. Numerical experiments showed that fast-response units can improve the reliability of power systems with a large penetration of volatile WG, especially in the limited geographical area. The size of the problem becomes too large when considering detailed operation constraints, and the calculation time would increase. In such cases, proper simplifications, for example, decomposition methods or parallel simulation can be utilised for large system solutions.

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10 Appendix

10.1 Linearising non-linear constraint using auxiliary binary variables

Equation (34) represents a non-linear conditional constraint which is modelled in MILP by using an auxiliary integer variable approach presented in Table 8. Table 8 shows that (34) conditional non-linear constraints can be modelled by linear constraints as follows

$$PW_t - PW_{t-1} \leq (m - \varepsilon)\delta + \varepsilon \quad (37)$$

$$SCR_t - SRCU_t - \sum_{g=1}^{NG} (P_g^{\max} - P_{gt}) \leq M(1 - \delta) \quad (38)$$

$$SCR_t - SRCU_t - \sum_{g=1}^{NG} (P_g^{\max} - P_{gt}) \geq m(1 - \delta) \quad (39)$$

Table 8 MILP representation of conditions

#	Condition	Represented by
1	$\sum_j a_j x_j \leq b \rightarrow \delta = 1$	$\sum a_j x_j - (m - \varepsilon)\delta \geq b + \varepsilon$
2	$\delta = 1 \rightarrow \sum_j a_j x_j = b$	$\sum a_j x_j + M\delta \leq M + b$ $\sum a_j x_j + m\delta \geq m + b$
3	$\sum_j a_j x_j \geq b \rightarrow \delta = 0$	$\sum a_j x_j + (M + \varepsilon)\delta \leq M + b$
4	$\delta = 0 \rightarrow \sum_j a_j x_j = b$	$\sum a_j x_j - M\delta \leq b$ $\sum a_j x_j - m\delta \geq b$

Table 9 Generation data

Unit type	Capacity, MW	Ramp-up/down, MW/h	MSR, MW/min	d%	Levelised investment cost, k\$/MW/year	FOR, %
thermal	525	180	6	50	existing unit	5
gas	100	300	10	40	100	5
wind	90	90	0	0	existing unit	0

Table 10 Load profile

Months	Total, GWh	Average, MW	Peak, MW
January	239.45	321.42	413.74
February	209.82	312.23	403.81
March	223.62	300.56	388.47
April	196.62	273.09	351.59
May	204.82	275.29	394.36
June	226.82	315.02	466.41
July	228.14	306.63	499.66
August	249.26	335.02	503.42
September	208.97	292.11	429.61
October	208.16	279.78	359.77
November	203.43	283.05	377.92
December	222.98	299.70	414.55

Table 11 Six-bus system generation data

Bus number	Capacity, MW	Ramp up/down, MW/h	MSR, MW/min	d%	FOR, %
1	180	60	2	50	5
2	130	60	2	50	5
6	100	60	2	50	5

Table 12 Six-bus system transmission data

Line number	From bus	To bus	Reactance, Ω	Capacity, MW
1	1	2	0.17	130
2	2	3	0.037	120
3	1	4	0.258	170
4	2	4	0.197	140
5	4	5	0.037	100
6	5	6	0.14	170
7	3	6	0.018	160

$$PW_t - PW_{t-1} \leq M - (m + \varepsilon)\delta \quad (40)$$

$$SCR_t - SRCD_t - \sum_{g=1}^{NG} P_{gt} \leq M\delta \quad (41)$$

$$SCR_t - SRCD_t - \sum_{g=1}^{NG} P_{gt} \geq m\delta \quad (42)$$

where M is an upper bound and m is a lower bound for the expression $(\sum_j a_j x_j - b)$ and ε is a small tolerance value.

10.2. Data for centralised and distributed cases

Generation data and load profile are given in [Tables 9](#) and [10](#).

10.3 Six-bus system data

Six-bus system data are given in [Tables 11](#) and [12](#).

Integration of High Reliability Distribution System in Microgrid Operation

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Abstract— In this paper, the application of high reliability distribution system (HRDS) in the economic operation of a microgrid is studied. HRDS, which offers higher operation reliability and fewer outages in microgrids, is applied to looped networks in distribution systems. The microgrid model in this study is composed of distributed energy resources (DER) including distributed generation (DG), controllable loads, and storage. The microgrid would utilize the local DER as well as the main grid for supplying its hourly load economically which is subject to power quality and reliability requirements. The HRDS implemented at Illinois Institute of Technology (IIT) is used as a case study along with the local DER to increase the load point reliability and decrease the operation cost of the IIT microgrid. The availability of distribution lines, main grid supply, and microgrid generation is considered using the Markov chain Monte Carlo simulation in the microgrid scenarios. The reliability indices based on frequency and duration of outages are measured at the microgrid level and the load point level, and the potential system enhancements are discussed for improving the economic operation of the IIT microgrid.

Index Terms— Microgrid economics, high reliability distribution system, storage, stochastic security constrained unit commitment

NOMENCLATURE

Variables

$E_{k,t}^{(.)}$	Available energy in storage unit k at time t
$F_{c,(.)}$	Production cost function of a DG unit
g	Denote the main grid connection
i	Denote a DG unit
k	Denote a storage unit
$I_{(.)}^{(.)}$	Unit status; 1 means on and 0 means off
$I_{c,(.)}^{(.)}$	Indicator of storage unit in charging mode
$I_{dc,(.)}^{(.)}$	Indicator of storage unit in discharging mode
j, o	Index of bus
$P_{(.)}^{(.)}$	Dispatch of a unit/grid generation
$P_{c,(.)}^{(.)}, P_{dc,(.)}^{(.)}$	Charge/discharge power of storage unit
$P_{j,(.)}^{d,(.)}, Q_{j,(.)}^{d,(.)}$	Real/reactive served load at bus j
$P_{j,(.)}^{inj,(.)}, Q_{j,(.)}^{inj,(.)}$	Real/reactive injection at bus j
$PL_{j,o}^{(.)}$	Real power flow between buses j and o

$Q_{(.)}^{(.)}$	Reactive power generation of a unit
$QL_{j,o}^{(.)}$	Reactive power flow between buses j and o
s	Denote a scenario
$SD_{(.)}^{(.)}$	Shutdown cost of a generation unit
$SL_{j,o}^{(.)}$	Apparent power flow between buses j and o
$SU_{(.)}^{(.)}$	Startup cost of a generation unit
t	Hour index
$V_{j,t}^s$	Voltage of bus j at hour t in scenario s
$\theta_{(.)}^{(.)}$	Bus voltage angle

Constants

$B_{(.)}^{(.)}$	Imaginary part of microgrid admittance matrix
$b_{j,o}^{(.)}$	Susceptance of the branch between buses j and o
CS_i, CD_i	Startup/Shut down cost of the thermal DG unit i
$D_j^{(.)}$	Set of units/loads which are connected to bus j
$E_k^{\min}, E_k^{\max}$	Min/max energy stored in storage unit k
$E0_k, ET_k$	Initial and terminal energy stored in storage unit k
$G_{(.)}^{(.)}$	Real part of microgrid admittance matrix
$g_{j,o}^{(.)}$	Conductance of the branch between buses j and o
NB	Total number of buses in the system
NT	Total number of hours under study
p^s	Probability of scenario s
$P_{(.)}^{\min}, P_{(.)}^{\max}$	Min/max generation capacity
$P_{c,k}^{\min}, P_{c,k}^{\max}$	Min/max charging capacity of storage unit k
$P_{dc,k}^{\min}, P_{dc,k}^{\max}$	Min/max discharging capacity of storage unit k
$P_{D,t}$	Total microgrid load
$P_{j,(.)}^D$	Load at bus j
$Q_{(.)}^{\min}, Q_{(.)}^{\max}$	Min/max reactive power capacity of unit
$r_{j,o}, x_{j,o}$	Line resistance & reactance between buses j and o
$SL_{o,j}^{\max}$	Maximum line capacity between buses j and o
$U_{j,o}^{(.)}$	Line availability between buses j and o
$UX_{(.)}^{(.)}$	Generation availability, 1 if available, otherwise 0
$VOLL$	Value of lost load

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$y_{j,o}$	Admittance connected between buses j and o
ρ_t	Hourly price of the grid supply
η_k	Charge/discharge cycle efficiency of storage unit k

I. INTRODUCTION

MICROGRIDS are considered as viable options for the electrification in university campuses, military installations, and other locations where the main grid expansion is either impossible or has no economic justification [1]. The operation and control of microgrids with distributed energy resources (DER) could also reduce the transmission burden on a power utility system. DER in a microgrid could include combined heat and power (CHP), photovoltaic (PV), small wind turbines (WT), heat or electricity storage, and controllable loads. DER applications increase the efficiency of energy supply and reduce the electricity delivery cost and carbon footprint in a microgrid. DER applications could also make it possible to impose intentional islanding in microgrids [2]. The proximity of generation to loads in microgrids could improve the power quality and reliability (PQR) at load points.

The emergence of microgrids in power utility systems has raised additional technical, economical, and regulatory challenges [3]. Matching generation and load to maintain the frequency and managing reactive power to regulate voltages and minimize losses are important issues in microgrid operations especially when microgrids are operated in an island mode. Storage devices including batteries, super-capacitors, and flywheels are used to match generation with load in microgrids. Storage can supply generation deficiencies, reduce load surges by providing ride-through capability for short periods [4], reduce network losses [5], and improve the protection system by contributing to fault currents [6].

The operation and control of automated switches can improve PQR indices in microgrids. Proper control signals would ensure the economics and the security of microgrids in grid-connected and island modes. Control schemes in microgrids include hierarchical and decentralized controls. The decentralized control facilitates distributed control and management of large complex systems by offering small autonomous systems referred to as agents. However, decentralized control requires significant experimentation with coordination before implementation and could introduce security challenges [7]. In [8], the economic operation of microgrids is evaluated by incorporating a hierarchical control. Hierarchical control is performed by a master controller which matches generation and load for real and reactive power control. The voltage-reactive power and frequency-real power characteristics of DGs would provide the required real and reactive power to adjust the voltage and frequency in microgrids. The master controller is responsible for maintaining the frequency in a microgrid by adjusting DG according to their frequency droop characteristics, utilizing storage, and load shedding. Moreover, voltage control strategies can be utilized by the master controller considering the voltage/reactive power droop of DGs so that there would be no reactive circulating currents among such resources. The

Kyotango microgrid project in Japan is an example of hierarchically controlled microgrid [1]. In [9]-[11], the role of power sharing is evaluated to regulate the frequency and the voltage in microgrids.

From the reliability point of view, microgrids can provide higher reliability and power quality at load points. The proximity of DG and load could decrease the duration and the frequency of outages as well as the level of energy not supplied at a microgrid [12]-[13]; however, the microgrid topology could play a crucial role in supplying the microgrid loads with diverse reliability requirements. In a grid-connected mode, outages of the main grid could lead to the microgrid islanding. In the island mode, the master controller relies on the microgrid generation and storage to balance the load with generation and prevent load curtailments. The load-supply balancing in an islanded microgrid could depend on the load priority and reliability requirements. In [14], the effect of load-supply mismatch on the microgrid reliability indices is evaluated by incorporating the stochastic nature of DGs. Ref. [15] addresses the load serving sequence in microgrids considering load point reliability indices.

This paper will evaluate the effect of HRDS switches and storage facilities on increasing the reliability indices in looped distribution systems. HRDS is introduced and applied to the IIT microgrid and the improvements on reliability indices are evaluated. The proposed reliability indices include the system average interruption frequency index (SAIFI), system average interruption duration index (SAIDI), customer average interruption duration index (CAIDI), customer average interruption frequency index (CAIFI), expected energy not supplied (EENS), and loss of load expectation (LOLE). The numerical results show that the integration of HRDS switches will help improve the reliability indices in a microgrid. Moreover, it is shown that integrating storage will not only improve the reliability indices in a microgrid but also reduce the operation cost at consumer levels. Section II introduces the HRDS and automatic switches. Section III presents the mathematical formulation and the solution methodology for the optimal operation and control of microgrids. Section IV presents an overview of the IIT microgrid and Section V discusses the optimal operation and control of IIT microgrid and evaluates the effect of HRDS on the IIT microgrid and consumer reliability indices. The conclusions are presented in Section VI.

II. HIGH RELIABILITY DISTRIBUTION SYSTEM

The implementation of microgrid loops is made possible by the use of automatic switches in HRDS. An example of HRDS is to apply Vista switches, equipped with SF₆ gas insulated fault interrupters, manufactured by the S&C Electric Company. HRDS switches can sense the cable faults and isolate the faulted section with no impact on other sections in a microgrid. The master controller will monitor the status of each HRDS switch using the supervisory control and data acquisition (SCADA) system. The master controller is responsible for economic operation of the microgrid based on signals received from switches on the status of distribution branches. Fig.1 shows the sample microgrid network with a

traditional protection scheme. Fig. 2 shows the HRDS implementation.

Comparing Figs. 1 and 2, it is clear that any line outages in microgrid shown in Fig. 1 will lead to load interruptions. In Fig. 1, if a fault occurs on the line connecting buses 2 and 3, the switches 4 and 5 will open and the load at buses 3 and 4 will be interrupted. In Fig. 2, if a fault occurs on the line connecting buses 2 and 3, switches 4 and 5 detect the fault according to the fault current direction and clear the fault without any interruptions to the loads at buses 3 and 4. Hence, loads will remain in service. In this case, all switches remain closed except S4 and S5. By incorporating the fiber optic technology for the communications between switches and fast response directional relays, the fault in Fig. 2 is cleared in less than 6 cycles (0.1 sec) which will not be sensed by the other microgrid loads.

Fig. 1 Sample of a microgrid without HRDS switches

Fig. 2 Sample of a microgrid with HRDS switches

The relays incorporated in HRDS switchgears provide permissive over-reaching transfer trip (POTT) and directional comparison blocking (DCB) protection. Before isolation, POTT monitors the direction of over-current relays on both sides of the cable to confirm that there is a fault. DCB acts as a backup protection system which tends to isolate the fault once the short circuit current is sensed by switches; however, POTT sends blocking signals if a fault is not occurred between the switches. As a backup protection scheme, DCB is always active in the microgrid even if the distribution system is open-looped. Fiber optics is used as a communication medium between relays and switches. The fiber optic communication system is capable of transferring the information in less than 2 msec which enables the main protection system to clear the fault in less than 6 cycles. The backup non-directional over current protection will operate if the primary protection scheme or the communication system fails.

III. OPTIMAL OPERATION OF MICROGRIDS

At steady state, the microgrid master controller will minimize the operation cost of DG, including startup and shut down costs, the cost of energy supplied by the main grid, and penalty costs (i.e., value of lost load) associated with the microgrid load curtailments. The optimal solution is subject to microgrid and the main grid constraints. The master controller will create an islanded microgrid in the case of grid contingencies and supply the microgrid loads by the local microgrid generation.

In this paper, a stochastic security-constrained unit commitment formulation is proposed for the master controller which is solved using the mixed-integer programming (MIP) model for the microgrid generation, grid supply and battery storage. The master controller objective and constraints are shown in (1)-(25). The load balance constraint is shown in (2). The mismatch represents the lost load, which is minimized in the objective function by penalizing the value of lost load. (3)-(4) represent the startup and shutdown costs of local generation. The real and reactive power generation constraints by the local and the main grid generation are shown in (5)-(8), respectively. The substation transformers/breakers will limit the energy trades with the main grid. Microgrid outages could further constrain such trades.

The microgrid storage will store energy when the market price of electricity is low and supply energy to the microgrid when the hourly market price is high. The storage constraints are shown in (9)-(16). The dispatch of storage unit is represented by (9). The constraint on the storage commitment is represented by (10) and charge/discharge capacity limits are shown in (11)-(12). The reactive power supplied by power electronic interface of the storage unit is shown in (13) [20]. The available energy at hour t is shown in (14) which is dependent on the available energy at hour $(t-1)$ and the charged/discharged energy at hour t . In (14), the hourly charged/discharged energy is restricted by the charge/discharge cycle efficiency of the storage unit. The limitation on stored energy which is represented by min/max state of charge of the storage unit is represented by (15) and (16). The net injected real/reactive power at each bus is shown in (17)-(18). Eq. (19) shows the admittance of distribution lines. The linearized formulation of real/reactive power injections are given in (20)-(21). Eq. (22)-(23) show the linearized formulation of real and reactive line flow and (24) represents the apparent power flow through the distribution line. Here, $\zeta_{j,o}^{t,s}$ is an auxiliary parameter, which is dependent on the load power factor as calculated in Appendix. The constraint on apparent power flow which is enforced by the line capacity is shown in (25).

Random outages are considered in the main grid and the microgrid. The Monte Carlo representation of outages is applied and the Latin Hypercube Sampling (LHS) technique is used to develop a large number of scenarios with equal probabilities. A two-state Markov chain process is utilized to represent microgrid outages according to the microgrid component outage and repair rates. The scenario reduction technique is applied to reduce the number of generated scenarios to an acceptable level with the corresponding

probabilities. Scenario reduction will eliminate the low probability scenarios and bundle scenarios that are close in terms of statistical metrics [16]-[18].

The MIP formulation in each scenario is decomposed into a master problem and several subproblems based on the linear programming duality theory [21]. In each scenario, the master problem determines the hourly unit commitment and dispatch solution of generation and storage facilities while the subproblems will check the distribution network constraints. In the case of violations, Benders cuts are generated and added to the master problem. The master problem is solved with the new constraints and the network constraints are checked in the next step. This iterative process will continue until there is no further transmission violation [21]-[23].

$$\text{Min} \sum_s p^s \left\{ \sum_t \sum_i \left(F_{c,i}^s(P_{i,t}^s) + SU_{i,t}^s + SD_{i,t}^s \right) + \rho_t \cdot P_{g,t}^s + VOLL \cdot \left(\sum_t \sum_j P_{j,t}^D - P_{j,t}^{d,s} \right) \right\} \quad (1)$$

s.t.

$$\sum_i P_{i,t}^s + P_{g,t}^s + \sum_k P_{k,t}^s = \sum_j P_{j,t}^{d,s} \quad (2)$$

$$SU_{i,t}^s \geq CS_i \cdot (I_{i,t}^s - I_{i,t-1}^s) \quad (3)$$

$$SD_{i,t}^s \geq CD_i \cdot (I_{i,t-1}^s - I_{i,t}^s) \quad (4)$$

$$P_i^{\min} \cdot UX_{i,t}^s \cdot I_{i,t}^s \leq P_{i,t}^s \leq P_i^{\max} \cdot UX_{i,t}^s \cdot I_{i,t}^s \quad (5)$$

$$P_g^{\min} \cdot UX_{g,t}^s \leq P_{g,t}^s \leq P_g^{\max} \cdot UX_{g,t}^s \quad (6)$$

$$Q_i^{\min} \cdot I_{i,t}^s \cdot UX_{i,t}^s \leq Q_{i,t}^s \leq Q_i^{\max} \cdot I_{i,t}^s \cdot UX_{i,t}^s \quad (7)$$

$$Q_{grid}^{\min} \cdot UX_{g,t}^s \leq Q_{g,t}^s \leq Q_{grid}^{\max} \cdot UX_{g,t}^s \quad (8)$$

$$P_{k,t}^s = P_{dc,k,t}^s - P_{c,k,t}^s \quad (9)$$

$$I_{dc,k,t}^s + I_{c,k,t}^s \leq 1 \quad (10)$$

$$I_{c,k,t}^s \cdot P_{c,k}^{\min} \leq P_{c,k,t}^s \leq I_{c,k,t}^s \cdot P_{c,k}^{\max} \quad (11)$$

$$I_{dc,k,t}^s \cdot P_{dc,k}^{\min} \leq P_{dc,k,t}^s \leq I_{dc,k,t}^s \cdot P_{dc,k}^{\max} \quad (12)$$

$$Q_k^{\min} \cdot (I_{dc,k,t}^s + I_{c,k,t}^s) \leq Q_{k,t}^s \leq Q_k^{\max} \cdot (I_{dc,k,t}^s + I_{c,k,t}^s) \quad (13)$$

$$E_{k,t}^s = E_{k,t-1}^s - (P_{dc,k,t}^s - \eta_k \cdot P_{c,k,t}^s) \quad (14)$$

$$E_k^{\min} \leq E_{k,t}^s \leq E_k^{\max} \quad (15)$$

$$E_{k,0} = E_{k,NT} \quad (16)$$

$$\sum_{i \in D_j^i} P_{i,t}^s + \sum_{g \in D_j^g} P_{g,t}^s + \sum_{k \in D_j^k} P_{k,t}^s - \sum_{d \in D_j^d} P_{d,t}^{d,s} = P_{j,t}^{inj,s} \quad (17)$$

$$\sum_{i \in D_j^i} Q_{i,t}^s + \sum_{g \in D_j^g} Q_{g,t}^s + \sum_{k \in D_j^k} Q_{k,t}^s - \sum_{d \in D_j^d} Q_{d,t}^{d,s} = Q_{j,t}^{inj,s} \quad (18)$$

$$y_{o,j}^{t,s} = g_{o,j}^{t,s} + Jb_{o,j}^{t,s} = \frac{r_{o,j} \cdot U_{o,j}^{t,s}}{r_{o,j}^2 + x_{o,j}^2} - J \frac{x_{o,j} \cdot U_{o,j}^{t,s}}{r_{o,j}^2 + x_{o,j}^2} \quad (19)$$

$$P_{j,t}^{inj,s} = (2V_{j,t}^s - 1) \cdot G_{j,j}^{t,s} + \sum_{o(j \neq o)}^{NB} G_{j,o}^{t,s} (V_{j,t}^s + V_{o,t}^s - 1) + B_{j,o}^{t,s} (\theta_{j,t}^s - \theta_{o,t}^s) \quad (20)$$

$$Q_{j,t}^{inj,s} = -(2V_{j,t}^s - 1) \cdot B_{j,j}^{t,s} + \sum_{o(j \neq o)}^{NB} -B_{j,o}^{t,s} (V_{j,t}^s + V_{o,t}^s - 1) + G_{j,o}^{t,s} (\theta_{j,t}^s - \theta_{o,t}^s) \quad (21)$$

$$PL_{j,o}^{t,s} = G_{j,o}^{t,s} (V_j^{t,s} - V_o^{t,s}) + B_{j,o}^{t,s} (\theta_j^{t,s} - \theta_o^{t,s}) \quad (22)$$

$$QL_{j,o}^{t,s} = B_{j,o}^{t,s} (V_o^{t,s} - V_j^{t,s}) + G_{j,o}^{t,s} (\theta_j^{t,s} - \theta_o^{t,s}) \quad (23)$$

$$SL_{j,o}^{t,s} = PL_{j,o}^{t,s} + \xi_{j,o}^{t,s} \cdot QL_{j,o}^{t,s} \quad (24)$$

$$|SL_{j,o}^{t,s}| \leq SL_{j,o}^{\max} \quad (25)$$

IV. THE PERFECT POWER SYSTEM - IIT MICROGRID

In 2004-2006, the underground distribution system at IIT suffered 12 unplanned power outages which disrupted academic and administrative activities and damaged several operation and research equipment. The outages were due to partial or complete loss of the utility supply and malfunctions of aged cables and other distribution components at IIT. The lack of system redundancy and the unavailability of replacement components prolonged the outage durations at IIT. In 2005, the Galvin Electricity Initiative lead a campaign to implement a perfect power system at IIT with the objective of establishing a microgrid that is environmentally friendly, fuel efficient, robust, and resilient with a self-healing capability. The microgrid at IIT empowers the campus consumers, in response to the real time price of electricity, to control daily power consumptions. IIT microgrid enhances its operation reliability by applying a real-time reconfiguration of power distribution assets, real-time islanding of critical loads, and real-time optimization of power supply resources.

Fig. 3 shows the configuration of the ComEd distribution network (main grid) that feeds the IIT microgrid. IIT is supplied by three 12.47 KV circuits fed from the ComEd Fisk substation. The peak load at IIT is approximately 10 MW. The IIT's 4.16 KV distribution system consists of 12.47/4.16 kV transformers, supply/feeder breakers and building transformers. Siegel Hall is the pilot building for the perfect power demonstration which is fed through the primary - which is backed up by a secondary (redundant) - feeder equipped with automatic switch. The voltage is further stepped down to 120 V in the building.

Fig. 3 ComEd system configuration feeding IIT substations [24]

In Fig. 4, the IIT microgrid consists of seven loops. The North Substation feeds three loops while the South Substation supplies energy to the remaining loops. Each building is supplied by redundant feeders which are normally energized to ensure that the building is fed by an alternate path in the case of an outage.

Fig. 4. IIT distribution system layout based on HRDS

Fig. 5 Third loop layout without HRDS switches

Fig. 6 Third loop layout with HRDS switches

The HRDS at IIT utilizes Vista underground closed loop fault-clearing switchgear with SEL-351 directional over-current protection relays. The fault isolation takes place in a quarter of a cycle by automatic breakers. The communication system is via fiber optic cables which facilitate the coordination between switches.

In Fig. 4, the third loop which is connected to the North Substation consists of five buildings including Hermann Hall, Wishnick Hall, Siegel Hall, Perlstein Hall, and Alumni Hall. Figs. 5 and 6 show the third loop with and without HRDS switches. It is also assumed that the redundant cables in Figs. 5 and 6 will be available when the primary feeding cable has failed. The load at Perlstein and Alumni Hall are aggregated as the Perlstein Hall load. In Fig. 5, an outage will result in downstream load curtailments until the manual switching restores the loads. Since the transfer switches are manually operated, the estimated time for manual source transfer at the building feeder is about three hours. In Fig. 6, the HRDS switches at load points provide uninterruptible load serving capability. Here, buildings are referred to as customers throughout the paper.

The IIT microgrid generation includes combustion microturbines connected to the North Substation as well as renewable energy sources. The IIT microgrid is equipped with an 8 MW gas-fired power plant which includes two 4 MW Rolls Royce gas turbines. The microgrid generation could be used for reliability and economic improvements in the main grid-connected and the island modes.

Renewable energy sources include wind and solar generation. An 8 kW Viryd wind turbine is installed on the north side of the campus in the Stuart soccer field. 60 kW of PV cells are installed on two building rooftops to supply portions of campus load. A 500 kWh ZBB storage is installed on campus to increase the reliability and efficiency of the IIT microgrid. Moreover, several electric vehicle charging stations are deployed on campus to utilize the microgrid energy storage and provide green energy for on campus electric vehicles.

A major element of the IIT microgrid is its master controller. Master controller applies a hierarchical control via SCADA to ensure reliable and economic operations of the IIT microgrid. It also coordinates the operation of HRDS controllers, on-site generation, storage, and individual building controllers [25]. Intelligent switching and advanced coordination technologies of master controller through communication systems facilitates rapid fault assessments and isolations in the IIT microgrid [24]. Fig. 7 shows the overview of the control tasks performed by master controller at IIT.

Fig. 7 Overview of the master controller system

The IIT microgrid participates in real-time electricity markets. Once the real-time price exceeds 7-8 cents per kWh (marginal cost of microgrid generation), the microgrid generation could serve the IIT load. The on-site generation can provide demand response and increase the reliability. The provision of spinning reserve and day ahead load response is also offered by master controller by managing microgrid generation, storage, controllable loads, power quality devices and smart switches.

V. SIMULATION OF IIT MICROGRID OPERATION

The master controller simulation at steady state and in contingencies (with and without HRDS) is considered. The simulation period is one year. The maximum loads at Hermann, Siegel, Wishnick, and Perlstein Halls are 289 kW, 167 kW, 272 kW and 513 kW, respectively. The typical Hermann Hall load is shown in Fig. 8, in which the weekend load is approximately 30% of that of weekdays.

Fig. 8 Load pattern in Hermann Hall

Tables I and II show the IIT distribution system characteristics with and without HRDS respectively. The line numbers are shown in Figs. 5 and 6. It is assumed that the backup lines are always available once they are energized to serve the loads. For example, in Fig. 5, once Lines 1, 2 or 3 fail, the Wishnick Hall load is served through Lines 4 and 9. Here, the microgrid generation capacity is 1 MW. The mean time to failure (MTTF) for the microgrid generation and grid supply is 1,200 hours and the mean time to repair (MTTR) of microgrid generation and grid supply is 25 hours. For simplicity, the charge/discharge efficiency and the availability of storage and HRDS switches are assumed to be 100%. The maximum charge/discharge rate of the 500 kWh ZBB storage unit is 250 kW/h.

The stochastic solution of microgrid provides the expected economic and reliability indices once HRDS switches and

storage are integrated into the IIT microgrid. The availability of distribution lines, grid supply, and microgrid generation is considered in scenarios using the Markov chain Monte Carlo (MCMC) simulation. The Monte Carlo simulation is applied to generate a large number of scenarios. The scenario reduction is applied to select 10 scenarios corresponding to Figs. 5 and 6 with their assigned probabilities. The reliability indices of microgrid are calculated and compared with and without HRDS switches. In the following, the contribution of master controller, HRDS, and storage to the reliability and the optimality of microgrid are evaluated for the eighth scenario, followed by a discussion on the results in other scenarios.

Table I Cable characteristic at IIT microgrid with HRDS

Line ID	Resistance ($\Omega/1000$ ft)	Inductance ($\Omega/1000$ ft)	Length (ft.)	Failure Rate (/yr)	MTTR (hr)	MTTF (hr)
1	0.028	0.037	159.2	0.2866	20	30,565
2	0.028	0.037	435.9	0.7846	20	11,164
3	0.028	0.037	144.5	0.2601	20	33,679
4	0.028	0.037	261.3	-	-	-
5	0.028	0.037	584	-	-	-
6	0.028	0.037	1,409.9	2.5378	20	3,451
7	0.028	0.037	755.7	-	-	-
8	0.028	0.037	452.7	0.8148	20	10,751
9	0.028	0.037	65.7	0.1182	20	74,111
10	0.028	0.037	376.8	-	-	-
11	0.028	0.037	99.4	0.1789	20	48,965
12	0.028	0.037	76.0	0.1368	20	64,035

Table II Cable characteristic at IIT microgrid without HRDS

Line ID	Resistance ($\Omega/1000$ ft)	Inductance ($\Omega/1000$ ft)	Length (ft.)	Failure Rate (/yr)	MTTR (hr)	MTTF (hr)
1	0.028	0.037	145.8	0.2624	20	33,384
2	0.028	0.037	382.6	0.6886	20	12,721
3	0.028	0.037	100.5	0.1809	20	48,424
4	0.028	0.037	758.1	-	-	-
5	0.028	0.037	182.6	0.3286	20	26,658
6	0.028	0.037	407.9	0.7342	20	11,931
7	0.028	0.037	250.0	0.45	20	19,466
8	0.028	0.037	238.5	-	-	-
9	0.028	0.037	92.6	-	-	-
10	0.028	0.037	30	-	-	-

In the following two options for the modeling of campus microgrid are studied. Option A applies a deterministic operation by considering the eighth scenario as the only alternative for the microgrid operation, and option B analyzes the stochastic behavior of the IIT microgrid.

A. Deterministic Operation of Microgrid

In this case, one scenario is closely analyzed and the effect of HRDS and the storage system on the microgrid reliability indices is evaluated. The following cases are studied:

Case 1: IIT microgrid is not equipped with HRDS switches (Fig. 5)

Case 2: IIT microgrid is equipped with HRDS switches (Fig. 6)

Case 3: IIT microgrid is equipped with HRDS switches and the storage system which is located next to Hermann Hall.

Table III shows the annual incidents with HRDS in the eighth scenario. The table shows that the first grid outage took place in the second day at hour 6 with two-hour duration while the second outage occurred on the fifth day which required a two-day repair. In the eighth scenario, there are five cable outages in the system equipped with HRDS switches while there is only one cable outage in the system without HRDS switches. Without HRDS, line L6 failed on the 224th day at hour 23 and was restored on the 225th day at hour 6. The outages of the main grid and DG are the same in both systems. In this scenario, we could have additional outages with HRDS because there are more components in a loop; however, the loads have never been interrupted.

Table III IIT microgrid with HRDS (start and end date of outage, day/hr)

	Grid	Power Plant	L1	L2	L6	L8
First Outage	2/6-2/8	88/19-88/21	212/12-212/18	7/6-8/16	67/17-69/1	59/20
Second Outage	5/1-7/6	146/11-147/7	-	-	174/14-175/12	-
Third Outage	38/10-39/21	334/13-336/23	-	-	-	-
Fourth Outage	193/9-194/10	337/20-338/17	-	-	-	-
Fifth Outage	201/18-202/9	343/22-345/1	-	-	-	-
Sixth Outage	280/12-280/19	-	-	-	-	-
Seventh Outage	284/13-289/17	-	-	-	-	-
Eighth Outage	311/18-311/23	-	-	-	-	-

a) Economic Operation of Microgrid

The microgrid operation cost includes the cost of main grid energy transactions (in both directions), cost of microgrid energy supply, and curtailment costs (value of lost load.) The operation cost of storage is assumed negligible. When the hourly market price of energy is higher than the marginal cost of microgrid generation, the microgrid could supply its excess energy to the main grid for reducing its operation cost. The main grid electricity prices in this study are based on historical hourly electricity prices of commercial customers [26].

Proper protective devices are located in the microgrid at the point of common coupling (PCC) which enables bi-directional power flows. The failure rate of the grid indicates the failure rate of the interface facilities at PCC. It is assumed that the price of electricity for trading with the grid is the same as the grid LMP at PCC.

The microgrid outages could result in the loss of revenue estimated at 80\$/kWh (value of lost load) which covers the replacement cost of the damaged equipment (campus facilities as well as those in laboratories), personnel and administrative cost of restoring and sustaining research and educational experiments, cost of aggravation associated with disrupted academic classes, laboratories, and any other major campus events such as open houses and conferences that are interrupted by microgrid outages.

The annual operation cost in Case 1 is 140,497\$/yr. The HRDS implementation reduces the operation cost to 126,644\$/yr. The use of storage will further reduce the annual operation cost to 119,236\$/yr by performing demand response and taking daily market price fluctuations into account. The

lost loads in the three Cases are 173.236, 0, and 0 kWh/yr, respectively.

Fig. 9 shows the microgrid energy flow on the 23rd day of the year. Here the energy drawn from the main grid is stored at the storage when the main grid hourly prices are low (hours 4, 5, 16 and 17) and deployed once the main grid prices are high (hours 10, 11, 19 and 20.) The main grid prices in Fig. 9 are not high enough to trigger the local microgrid generation. The lowest prices at the microgrid occurs at hours 4 and 5 (2.4 ¢/kWh) which increase to 3.5 and 3.6 ¢/kWh at hours 10 and 11, respectively. This cycle is repeated at hours 16-17 and 19-20.

Fig. 10 shows the energy supply to the microgrid on the 217th day (summer day) when the main grid electricity prices are higher. Here, the local microgrid generation is dispatched at hour 10 when the main grid prices are higher than 6¢/kWh. The microgrid revenue for a single day energy sale is \$473.699.

Fig. 9 Storage and the main grid supply on the 23rd day.

Fig. 10 Microgrid and the main grid supply on the 217th day.

b) Microgrid Reliability Evaluation

In this case, interruption indices for consumers and the entire microgrid are evaluated. There are four customers in the third loop. In Case 1, there is a single load interruption in Perlstein Hall, so SAIFI and CAIFI are 0.25 (interruption/customer.yr) and 1 (interruption/affected customer.yr) respectively. The outage duration is 3 hours and SAIDI and CAIDI are 0.75 (hrs/customer.yr) and 3 (hrs/customer interruption.yr) respectively. In Case 2, no microgrid outages occur which decreases SAIFI, CAIFI, SAIDI and CAIDI to zero. Likewise, in Case 3, SAIFI, CAIFI, SAIDI and CAIDI are zero.

The results show that the HRDS integration will decrease the microgrid outage duration and frequency in Case 2, and lower the microgrid SAIFI, SAIDI, CAIDI and CAIFI. In Cases 2 and 3, we could have additional outages with HRDS because there are more components in a loop; however, the loads would never be interrupted as shown in Table IV. In the eighth scenario, there is only one outage at L6 in Case 1 which lasts 9 hours. Since the manual switching takes 3 hours and the

building is fed by the redundant path after manual switching, this event leads to a 3 hour outage and 173.236 kWh energy not supplied in Perlstein Hall. The EENS and LOLE in this case are 173.236 kWh/yr and 3 hours/yr respectively. In Cases 2 and 3 there are 5 cable outages which lasted 103 hours; however, these events did not interrupt the served loads because of HRDS.

Table IV. Annual energy not supplied at load points

	Hermann Hall (kWh/yr)	Siegel Hall (kWh/yr)	Wishnick Hall (kWh/yr)	Perlstein Hall (kWh/yr)
Case 1	0	0	0	173.236
Case 2	0	0	0	0
Case 3	0	0	0	0

B. Stochastic Solution of Microgrid Operation

a) Operation Cost

A scenario reduction technique was applied to select 10 scenarios from a large number of scenarios generated by the MCMC method [27], [28]. The scenario reduction algorithms include fast backward, fast forward/backward and fast backward/backward methods [28]. The algorithms are chosen according to the size of the stochastic problem and the required solution accuracy. For large scenario trees, the fast forward method provides a more accurate solution with a longer processing time. In this paper, a fast backward/forward method is used for the scenario reduction. The probabilities of 10 stochastic scenarios are shown in Table V.

Table V. Probability of stochastic scenarios after scenario reduction

Scenario No.	1	2	3	4	5
Probability	0.107	0.119	0.126	0.0326	0.084
Scenario No.	6	7	8	9	10
Probability	0.125	0.092	0.108	0.0964	0.11

Table VI. Operation cost of stochastic scenarios in Case 1

Scenario No.	1	2	3	4	5
Operation Cost (\$/yr)	182,655	191,727	154,340	730,330	232,863
Scenario No.	6	7	8	9	10
Operation Cost (\$/yr)	226,398	192,773	140,497	238,694	303,518

Table VII. Operation cost of stochastic scenarios in Case 2

Scenario No.	1	2	3	4	5
Operation Cost (\$/yr)	127,087	125,041	125,750	609,400	124,609
Scenario No.	6	7	8	9	10
Operation Cost (\$/yr)	127,544	127,861	126,644	152,777	146,649

Table VIII. Operation cost of scenarios in Case 3

Scenario No.	1	2	3	4	5
Operation Cost (\$/yr)	119,525	117,513	118,223	549,537	117,108
Scenario No.	6	7	8	9	10
Operation Cost (\$/yr)	120,045	119,109	119,236	122,157	120,968

The operation costs of scenarios are shown in Tables VI-VIII. Here, the operation cost of Case 2 is lower than that in Case 1 in all scenarios because HRDS can reduce the energy not supplied and its respective penalties. The storage will also reduce the duration of microgrid load curtailments and the annual energy not supplied. Comparing Tables VIII and VII, it is shown that the cost in Case 3 is decreased as compared to that in Case 2. The expected operation costs in Cases 1-3 are 224,073\$/yr, 146,899\$/yr and 120,038\$/yr respectively. The estimated saving at the IIT microgrid with HRDS installed at all seven loops is 621,867\$/yr.

b) Microgrid Reliability indices

Tables IX-XI show the microgrid system and customer interruption indices in stochastic scenarios. Table X shows the HRDS reduces SAIFI and SAIDI; however, it may not decrease CAIDI and CAIFI consistently. In the seventh scenario, CAIFI is not reduced in Case 2 because fewer outages will affect fewer customers proportionally which leads to an equal frequency of interruption per affected customer per year. In Case 1, there are 3 outages which affect 3 customers. In Case 2, there is a single outage which affected one customer; hence the CAIFI in Cases 1 and 2 are equal. In the fourth scenario, CAIDI in Case 2 is increased as compared to Case 1. The reason for a higher CAIDI is that the frequency of interruption drops faster than the duration of interruption; hence the duration of interruption per affected customer per year is higher.

Table IX. Microgrid and consumer interruption indices in Case 1

Scenario No.	1	2	3	4	5
SAIFI (int./cust.yr)	0.25	1.25	0.5	3.5	1.5
SAIDI (hr/ cust. yr)	0.75	2.25	1.5	18	3.75
CAIFI (int./aff. cust. yr)	1	1.25	1	3.5	3
CAIDI (hr/cust. int. yr)	3	1.8	3	5.14	2.5
Scenario No.	6	7	8	9	10
SAIFI (int./cust.yr)	1.25	0.75	0.25	2.5	2.25
SAIDI (hr/ cust. yr)	3.75	1.75	0.75	5.25	5.75
CAIFI (int./aff. cust. yr)	1.66	1	1	3.33	2.25
CAIDI (hr/cust. int. yr)	3	2.33	3	2.1	2.55

Table X. Microgrid and consumer interruption indices in Case 2

Scenario No.	1	2	3	4	5
SAIFI (int./cust.yr)	0	0	0	1.75	0
SAIDI (hr/ cust. yr)	0	0	0	12.75	0
CAIFI (int./aff. cust. yr)	0	0	0	1.75	0
CAIDI (hr/cust. int. yr)	0	0	0	7.28	0
Scenario No.	6	7	8	9	10
SAIFI (int./cust.yr)	0	0.25	0	0.75	0.25
SAIDI (hr/ cust. yr)	0	0.25	0	1	0.5
CAIFI (int./aff. cust. yr)	0	1	0	1	1
CAIDI (hr/cust. int. yr)	0	1	0	1.33	2

Table XI. Microgrid and consumer interruption indices in Case 3

Scenario No.	1	2	3	4	5
SAIFI (int./cust.yr)	0	0	0	1.25	0
SAIDI (hr/ cust. yr)	0	0	0	11.25	0
CAIFI (int./aff. cust. yr)	0	0	0	1.25	0
CAIDI (hr/cust. int. yr)	0	0	0	9	0
Scenario No.	6	7	8	9	10
SAIFI (int./cust.yr)	0	0	0	0	0
SAIDI (hr/ cust. yr)	0	0	0	0	0
CAIFI (int./aff. cust. yr)	0	0	0	0	0
CAIDI (hr/cust. int. yr)	0	0	0	0	0

In Case 2, the duration of interruption is 51 hours/yr and the frequency of interruptions is 7, while in Case 1, the duration of interruption is 72 hours and the frequency of interruption is 14. Although the frequency of interruption is decreased by a half, the duration of interruption is not decreased proportionally, leaving a higher CAIDI in Case 2. In Case 2, most scenarios have lower CAIDI and CAIFI than those in Case 1. Although it is not shown, CAIFI can also be higher in some scenarios in Case 2, as compared to that in Case 1, if the number of outages and the affected customers are not reduced proportionally. CAIDI is dependent on the duration and the frequency of outages. In some scenarios, CAIDI is higher because the

frequency and the duration of outages are not reduced proportionally. So the HRDS implementation will lead to shorter frequency and duration for outages with lower SAIFI and SAIDI.

Table XII. Energy not supplied at load points in Case 1 (kWh/yr)

Scenario No.	1	2	3	4	5
Hermann Hall	0	56.662	0	1,413.705	0
Wishnick Hall	0	495.024	0	1,951.124	0
Siegel Hall	0	32.803	292.129	1,370.819	404.838
Perlstein Hall	694.830	249.597	65.467	2,802.999	948.843
Total	694.830	834.086	357.596	7,538.647	1,353.681
Scenario No.	6	7	8	9	10
Hermann Hall	172.573	0	0	0	437.242
Wishnick Hall	658.611	17.793	0	622.114	1,129.902
Siegel Hall	405.045	84.496	0	645.066	580.567
Perlstein Hall	0	903.08	173.236	96.612	42.08
Total	1,236.229	1,005.369	173.236	1,363.792	2,189.791

Table XIII. Energy not supplied at load points in Case 2 (kWh/yr)

Scenario No.	1	2	3	4	5
Hermann Hall	0	0	0	1,451.496	0
Wishnick Hall	0	0	0	1,356.101	0
Siegel Hall	0	0	0	791.003	0
Perlstein Hall	0	0	0	2,427.678	0
Total	0	0	0	6,026.278	0
Scenario No.	6	7	8	9	10
Hermann Hall	0	17.793	0	61.401	227.972
Wishnick Hall	0	0	0	68.201	0
Siegel Hall	0	0	0	159.771	0
Perlstein Hall	0	0	0	0	0
Total	0	17.793	0	289.373	227.972

Table XIV. Energy not supplied at load points in Case 3 (kWh/yr)

Scenario No.	1	2	3	4	5
Hermann Hall	0	0	0	1,248.662	0
Wishnick Hall	0	0	0	1,017.405	0
Siegel Hall	0	0	0	769.404	0
Perlstein Hall	0	0	0	2,335.710	0
Total	0	0	0	5,371.181	0
Scenario No.	6	7	8	9	10
Hermann Hall	0	0	0	0	0
Wishnick Hall	0	0	0	0	0
Siegel Hall	0	0	0	0	0
Perlstein Hall	0	0	0	0	0
Total	0	0	0	0	0

Table XV. Total outage duration in Cases and Scenarios (hr/yr)

Scenario No.	1	2	3	4	5
Case 1	3	9	6	72	15
Case 2	0	0	0	51	0
Case 3	0	0	0	45	0
Scenario No.	6	7	8	9	10
Case 1	15	7	3	21	23
Case 2	0	1	0	4	2
Case 3	0	0	0	0	0

Table XVI. Expected reliability and economic indices

Case	1	2	3
Exp. SAIFI (int./cust.yr)	1.22	0.18	0.04
Exp. SAIDI (hr/ cust. yr)	3.29	0.59	0.37
Exp. CAIFI (int./aff. cust. yr)	1.73	0.36	0.04
Exp. CAIDI (hr/cust. int. yr)	2.69	0.68	0.29
Exp. Operation Cost (\$/yr)	224,073	146,899	120,038
Exp. Energy not Supplied (kWh/yr)	1,216.21	251.07	175.10
LOLE (hr/yr)	13.153	2.360	1.467

In Case 3, SAIFI, SAIDI and CAIFI are reduced as compared to that in Case 2; however, CAIDI in the fourth scenario is higher. In this scenario, there are 7 outages in Case 2 as compared to 5 outages in Case 3, and the outage duration is dropped from 51 hours in Case 2 to 45 hours in Case 3.

Hence, CAIDI is higher in Case 3 since the duration of interruption drops more slowly than its frequency.

In Table XII, scenario 4 corresponds to a generation failure when the grid fails. In this case, the storage unit would supply the load partially which is supplemented by the microgrid load curtailment. Table V shows a lower probability in this case.

Although interruption frequency indices are lower, the integration of microgrid storage may not decrease SAIFI and CAIFI in all scenarios since the storage will lower the unserved load rather than the frequency of interruptions. However, the expected SAIFI and CAIFI will be lower when the storage is implemented. When the storage is introduced, SAIFI, SAIDI, CAIFI and CAIDI are lowered to zero in Scenarios 7, 9 and 10, which shows that the storage can eliminate the energy not supplied. In summary, SAIDI and SAIFI are lowered in all scenarios once the HRDS is installed and SAIDI is lower with the microgrid storage in place.

Table XVI shows lower expected SAIFI, SAIDI, CAIFI and CAIDI when HRDS is implemented and demonstrates an enhance reliability when the storage is used. Tables XII-XIV show the energy not supplied. As expected, Case 3 shows the lower energy not supplied in each scenario due to storage. HRDS will lead to lower energy not supplied with the lowest expected energy not supplied in Case 3 followed by that of Case 2.

Storage can also reduce the LOLE in microgrids. In Table XV, Case 3 demonstrates the lowest outage hours followed by that in Case 2. The LOLE in Cases 1-3 are 13.15, 2.36, and 1.47 hr/yr which are reduced with HRDS switches and storage. Here, microgrid load shedding occurs when the main grid supply is unavailable. Table XVI shows the enhancements in Cases 2 and 3.

VI. CONCLUSIONS

In this paper, reliability and economic indices of a microgrid equipped with HRDS switches is analyzed. The simulation of the IIT microgrid is presented and the contributions are highlighted as follows:

- The stochastic AC network formulation for the master controller is offered to solve the hourly unit commitment and economic dispatch in microgrids.
- The role of local generation, main grid, and energy storage on the economic operation of microgrids is considered and the enhanced reliability indices at load points are calculated.
- Storage can reduce the operation cost of a microgrid by performing demand response and avoiding emergency load curtailments. Storage helps mitigate the expected interruption duration and frequency and improves the customer reliability in microgrids.
- HRDS is used for the evaluation of reliability and economic indices in microgrids which are compared to those in traditional distribution systems.
- The implementation of HRDS and automatic switches can reduce the expected frequency and the duration of interruptions and the expected energy not supplied in microgrids. HRDS can also reduce the expected operation

cost of a microgrid by mitigating emergency load curtailments and reducing the value of lost loads.

- Microgrid reliability indices are calculated with/without HRDS.
- It is estimated that the expected operation cost at the IIT microgrid would be lowered by \$621,867 annually by integrating HRDS; the storage can further reduce the operation cost by \$109,220.

APPENDIX

$\zeta_{j,o}^{t,s}$, derived here, is an auxiliary parameter which is dependent on the load power factor. The apparent power flow through the line is written as:

$$SL_{j,o}^{t,s} = \sqrt{(PL_{j,o}^{t,s})^2 + (QL_{j,o}^{t,s})^2} \quad (A1)$$

$$SL_{j,o}^{t,s} = PL_{j,o}^{t,s} \cdot \sqrt{1 + \left(\frac{QL_{j,o}^{t,s}}{PL_{j,o}^{t,s}} \right)^2} \quad (A2)$$

Using Taylor series:

$$SL_{j,o}^{t,s} = PL_{j,o}^{t,s} \cdot \left[1 + \frac{1}{2} \cdot \left(\frac{QL_{j,o}^{t,s}}{PL_{j,o}^{t,s}} \right)^2 \right] \quad (A3)$$

$$SL_{j,o}^{t,s} = PL_{j,o}^{t,s} + \frac{1}{2} \cdot QL_{j,o}^{t,s} \cdot \tan \theta_{j,o}^{t,s} \quad (A4)$$

where

$$\xi_{j,o}^{t,s} = \frac{1}{2} \cdot \tan \theta_{j,o}^{t,s} \quad (A5)$$

$$\theta_{j,o}^{t,s} = \tan^{-1} \left(\frac{Q_j^{t,s} + Q_o^{t,s}}{P_j^{t,s} + P_o^{t,s}} \right) \quad (A6)$$

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Microgrid-based Co-optimization of Generation and Transmission Planning in Power Systems

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Abstract— This paper presents an algorithm for the microgrid planning as an alternative to the co-optimization of generation and transmission expansion planning in electric power systems. The integration of microgrids in distribution systems will offer a decentralized control of local resources for satisfying the network reliability and the power quality required by local loads. The objective in this paper is to minimize the total system planning cost comprising investment and operation costs of local microgrids, the co-optimized planning of large generating units and transmission lines, and the expected cost of unserved energy. The cost of unserved energy reflects the cost of load shedding which is added to the objective function for reliability considerations. The microgrid-based co-optimization planning problem is decomposed into a planning problem and annual reliability subproblem. The optimal integer planning decisions calculated in the planning problem will be examined against the system reliability limits in the subproblem and the planning decisions will be revised using proper feasibility cuts if the annual reliability limits are violated. Numerical simulations demonstrate the effectiveness of the proposed microgrid-based co-optimization planning in power systems and explore the economic and reliability merits of microgrid planning as compared to grid-based generation and transmission upgrades.

Index Terms— Power system expansion planning, microgrids, co-optimization of transmission and generation planning, Annual reliability

NOMENCLATURE

Indices:

b	Index for load blocks
h	Index for periods
i	Index for generating units
l	Index for transmission lines
m	Index for buses
q	Index for microgrids
s	Superscript for scenarios
t	Index for years
$\wedge$	Index for calculated variables

Sets:

CG	Set of candidate generating units
CL	Set of candidate transmission lines
EG	Set of existing generating units

EL	Set of existing transmission lines
N_m	Set of components connected to bus m

Parameters:

B	Bus-line incidence matrix
CC	Capital cost
d	Discount rate
D	HV bus load demand
DT	Duration time
M	Large positive constant
NQ	Maximum number of microgrid installations
PD	Microgrid load demand
pr	Probability
T	Number of years in the planning horizon
T^{com}	Commissioning year
UX	Contingency state of generating units
UY	Contingency state of transmission lines
$VOLL$	Value of lost load
x	Reactance of line
κ	Coefficient of present-worth value
γ	Salvage factor

Variables:

C	Total investment and operation cost
CR	Cost of unserved energy
$EENS$	Expected energy not served
LS	Load shedding
OC	Operation cost
P	Unit generation
PL	Line flow
PM	Microgrid local generation
u	Microgrid investment state
y	Line investment state
z	Unit investment state
ω	System load curtailment
θ	Voltage angle
λ, μ, π	Dual variables

I. INTRODUCTION

Microgrids generate, distribute and regulate the flow of electricity to local customers, representing a modern small-scale power system with a high degree of flexibility and efficiency in both supply and demand sectors [1]-[5]. Technically, a microgrid is a system with at least one distributed energy resource (DER) and one demand which can be islanded from the main power distribution system. In

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practice, microgrids are introduced to address the emergence of a large number of DERs in distribution systems and to ensure secure and optimal operations of potentially islanded power grids.

A microgrid is considered as a controllable aggregated load from a utility's point of view. The hourly operation of a microgrid is controlled by the microgrid master controller instead of a central dispatch provided by the utility. The DERs located within a microgrid differ from conventional power plants as they possess a smaller capacity, are directly connected to the microgrid distribution network, and could be customized to supply local load requirements [6].

The benefits of a microgrid include the improved reliability by introducing self-healing at the local distribution network, higher power quality by managing local loads, reduction in carbon emission by the diversification of energy sources, economic operation by reducing T&D costs, utilization of less costly renewable energy sources, and offering energy efficiency by responding to real-time market prices [7]-[10].

The salient feature of a microgrid is its ability to be islanded from the main grid by upstream switches at the point of common coupling (PCC). Islanding could be introduced for economic as well as reliability purposes. During main grid disturbances, microgrid is transferred from the grid-connected to the islanded mode and a reliable and uninterrupted supply of consumer loads is offered by local generation resources. The microgrid master controller would offer the optimal operation by maintaining the frequency and voltages within permissible ranges. The islanded microgrid would be resynchronized with the main grid once the disturbance is removed [11]-[13].

Microgrid alternatives to the traditional T&D expansion could reduce the total planning cost and increase the system reliability with a local control option for lowering the possibility of load shedding. Microgrids offer a lower construction time and are regarded as viable options for reducing the transmission congestion when large investments on new generation and transmission facilities are not forthcoming [14]-[18].

Previous power system planning studies investigated generation and transmission expansion planning methodologies in a vertically integrated power system (where a centralized generation and transmission expansion is performed), and a market-based environment (where proposed generation and transmission expansion planning options are coordinated) [19]-[29]. However, existing planning approaches did not consider the impact of microgrid installations on the power system expansion.

This paper utilizes a co-optimization approach to the generation and transmission expansion planning which also considers the most suitable locations for microgrid installations in a power system. The proposed approach considers short-term operation constraints in conjunction with the co-optimization planning of generation and transmission. The proposed microgrid-based co-optimization approach will simulate the iterative and the interactive planning coordination among generation companies, transmission companies, and the ISO in a competitive electricity market.

The proposed microgrid-based co-optimization planning is a

mixed-integer programming (MIP) problem. The optimal cost of reliability is considered as an objective and the acceptable reliability level is modeled as a constraint. The Monte Carlo simulation is applied to simulate random component outages and a scenario reduction method is applied as a tradeoff between the computation time and the solution accuracy. The random outages of system components are considered in the calculation of annual expected energy not supplied (EENS).

The rest of the paper is organized as follows. Section II discusses the microgrid architecture and introduces microgrid components. Section III proposes the microgrid-based planning model, while Section IV presents the problem formulation. Section V presents illustrative examples to show the proposed model applied to a standard power system. Discussion on the features of the proposed model and concluding remarks are provided in Sections VI and VII, respectively.

II. MICROGRID MODEL

Fig. 1 depicts a typical microgrid configuration, where DERs are connected to loads through low voltage (LV) and medium voltage (MV) distribution networks. The PCC circuit breaker enables the microgrid islanding. The integration of DERs facilitates bidirectional electricity flows in the distribution network.

Fig. 1 A typical microgrid architecture (DG: distributed generation, ESS: energy storage system, PCC: point of common coupling)

The microgrids could be interconnected to form a cluster of microgrids. In this fashion, the loads in each microgrid would be supplied from several interconnected microgrids using a common distribution network. The interconnected microgrids would achieve greater stability and controllability as well as enhanced redundancy to ensure the supply reliability. The interconnection of microgrids significantly reduces the complexity in the control and operation of hundreds of individual DERs. DERs would seamlessly control power and provide required energy to local loads in the interconnection. We assume that DERs and loads are coordinated such that the microgrid generation is used solely to satisfy the interconnected microgrid loads or stored in the energy storage system. DERs in a microgrid are not designed to continuously generate power for supplying the main grid. By allowing such power transfers, the power system could further rely on the DER generation in lieu of large generation expansion planning. Thus, microgrids are regarded as controllable loads

in this study and no power generation is injected to the main grid from the interconnected microgrids. A microgrid may include several DERs with variable generation profiles; however, in this study, we assume DERs are aggregated in a cluster of microgrids for supplying local loads in which a microgrid is regarded a controllable load with a more settled hourly profile from the ISO's point of view. The intermittency of DERs inside a microgrid would require additional scenario generation to model DER operation. We assume the distribution network expansion is internalized as part of the microgrid cluster which would not be the ISO's concern.

III. PROPOSED MICROGRID-BASED PLANNING MODEL

Fig. 2 depicts the proposed microgrid-based planning model. We assume candidate microgrids installed at designated buses would normally be operated in a grid-connected mode. In the case of a main grid disturbance, however, the microgrid would switch over to an islanded mode to satisfy local loads. The investments are analyzed on an annual basis. A year is decomposed into multiple periods and the load duration curve (LDC) is utilized with load blocks at each period. The number and the duration of load blocks are considered as a tradeoff between the accuracy and the computation burden in the proposed planning model. The load forecast at every block in every period of the planning horizon is met by system operation and expansion planning decisions.

Fig. 2 Proposed microgrid-based co-optimization planning model

The planning problem in Fig. 2 co-optimizes the least-cost options of candidate generating units, transmission lines, and microgrids for supplying the load forecast and satisfying prevailing operation and planning constraints. The objective comprises investment costs and salvage values for new resources, operation costs of generating units and microgrids, and the cost of unserved energy.

A decomposition is applied in Fig. 2 to coordinate the operation and planning constraints as part of the co-optimization scheme. The decomposition would separate the

planning problem into a co-optimization of generation, transmission and microgrid, a short-term operation subproblem (which checks the transmission network constraints in the proposed plan) and an economic operation subproblem (which finds the optimal system operation based on the proposed plan). If the feasibility or the optimality check fails, proper cuts are generated in the corresponding subproblems and added to the next iteration of co-optimization of generation, transmission and microgrid. This iterative process will continue until a secure and optimal expansion planning solution is achieved.

IV. MICROGRID-BASED PLANNING PROBLEM FORMULATION

A. Planning Problem

The objective of the proposed microgrid-based planning problem is to minimize the total planning cost throughout the planning horizon as shown in (1)

$$\text{Min} \sum_t \sum_i \kappa_t C_{it} + \sum_t \sum_l \kappa_t C_{lt} + \sum_t \sum_m \sum_q \kappa_t C_{qmt} + \sum_t \kappa_t CR_t \quad (1)$$

Here, $\kappa_t = 1/(1+d)^{t-1}$ is the present-worth value coefficient. The objective includes investment and operation costs associated with new generating units, transmission lines, and microgrids, in addition to the cost of unserved energy. The objective is evaluated in terms of discounted costs, where discount rates are incorporated in the present-worth cost components. A higher discount rate would affect investments as candidates with higher investment costs become inferior. The cost of unserved energy in the objective would represent the economics of system reliability.

Equations (2)-(5) define cost terms used in the objective function. The generation costs (2) include the investment cost of new generating units and the operation cost of existing and installed units. The operation cost includes fuel and maintenance costs. The investment cost of new transmission lines is represented by (3). The salvage value, i.e., the percentage of depreciation of the initial investment, is included in the investment cost to represent the monetary value of the installed resource at the end of the planning horizon. κ_T is the worth value coefficient of the resources at the end of the planning horizon.

$$C_{it} = CC_i P_i^{\max} (z_{it} - z_{i(t-1)}) - \frac{\kappa_T}{\kappa_t} \gamma_{it} CC_i P_i^{\max} (z_{it} - z_{i(t-1)}) + \sum_h \sum_b DT_{bht} OC_i P_{ibht} \quad (2)$$

$$C_{lt} = CC_l PL_l^{\max} (y_{lt} - y_{l(t-1)}) - \frac{\kappa_T}{\kappa_t} \gamma_{lt} CC_l PL_l^{\max} (y_{lt} - y_{l(t-1)}) \quad (3)$$

$$C_{qmt} = CC_{qm} (PM_{qmt}^{\max} u_{qmt} - PM_{qm(t-1)}^{\max} u_{qm(t-1)}) - \frac{\kappa_T}{\kappa_t} \gamma_{qmt} CC_{qm} (PM_{qmt}^{\max} u_{qmt} - PM_{qm(t-1)}^{\max} u_{qm(t-1)}) + \sum_h \sum_b DT_{bht} OC_{qm} PM_{qmbht} \quad (4)$$

$$CR_t = VOLL_t EENS_t \quad (5)$$

The candidate generating units and transmission lines will

be commissioned once the planning, the detailed engineering design, and the construction work are completed. The commissioning time is dependent on the type and the size of the unit (6)-(7). Once a candidate generating unit or transmission line is installed, its investment state will be fixed at 1 for the remaining years in the planning horizon (8)-(9).

$$z_{it} = 0 \quad \forall i \in CG, \forall t < T_i^{\text{com}} \quad (6)$$

$$y_{lt} = 0 \quad \forall l \in CL, \forall t < T_l^{\text{com}} \quad (7)$$

$$z_{i(t-1)} \leq z_{it} \quad \forall i \in CG, \forall t \quad (8)$$

$$y_{l(t-1)} \leq y_{lt} \quad \forall l \in CL, \forall t \quad (9)$$

The investment and operation costs of a microgrid would depend on the size and the type of DERs used in the microgrid. The microgrid investment cost is assumed to be a linear function of its generation capacity. The operation cost is obtained based on the microgrid generation dispatch. The total planning cost of the microgrid is the sum of its investment and operation costs minus its salvage value (4).

The bus load supply is limited to the associated microgrid generation capacity (10)-(11). The microgrid would shift seamlessly from grid-connected to the islanded mode for supplying local loads. The microgrid generation (12) would either supply loads at associated microgrids or be stored at local storage facilities (rather than feeding the main grid loads). A microgrid could be subject to further expansion (13) to supply the local load forecast. Microgrids are interconnected to form a cluster so that the required reserve in one microgrid could be supplied by the interconnected microgrids where DERs would seamlessly provide the required energy to local loads in the interconnection. In a case that a microgrid is not interconnected to other microgrids, (10) would be modified to increase the installed capacity and further consider the required spinning reserve.

$$PM_{qmt}^{\max} = \max_{h,b} \{PD_{qmbht}\} \quad \forall q, \forall m, \forall t \quad (10)$$

$$PM_{qmbht} \leq PM_{qmt}^{\max} u_{qmt} \quad \forall q, \forall m, \forall b, \forall h, \forall t \quad (11)$$

$$\sum_q (PM_{qmbht} - PD_{qmbht}) \leq 0 \quad \forall m, \forall b, \forall h, \forall t \quad (12)$$

$$u_{qm(t-1)} \leq u_{qmt} \quad \forall q, \forall m, \forall t \quad (13)$$

The cost of unserved energy defined by (5) is obtained based on EENS and the value of lost load (VOLL). EENS is calculated in the subproblem and added in each iteration to the planning problem. The EENS in the first iteration is the base case system reliability. VOLL, which is the load shedding price for compensating customers, depends on several factors including the types of customers, the amount and the duration of load interruption, and the time of outage. A higher VOLL corresponds to lower load shedding [30]-[31]. VOLL is given as an input to our model.

The proposed co-optimization expansion planning objective is subject to prevailing operation constraints, such as the limits on generation, fuel, ramping, emission, etc., and transmission network constraints [32]-[33]. A dc power flow is used, where it is assumed that the voltage related concerns would be handled by the microgrid master controller. Additional details

on the decomposition of the planning problem are found in [34]-[37].

B. Role of Annual Reliability

Once the optimal planning decisions for microgrids and the main grid are made in the planning problem, the new system topology is sent to the subproblems to calculate the annual EENS. The annual reliability calculation at load block b , period h , year t and scenario s is formulated in (14)-(28).

The objective (14) is to minimize the load curtailment for balancing purposes in the case of system component outages [38]. Equation (15) defines the load balance at each system bus incorporating load shedding variable. The dual variables are obtained in (16)-(18) to represent the incremental reduction in load curtailments with regards to system investments. The dual variables are used to generate investment signals for consequent iterations of the planning problem. The existing and candidate generating unit capacity limits are defined by (19)-(20), respectively. Constraints on existing transmission lines are imposed by (21)-(22), while those of candidate transmission lines are (23)-(24). The microgrid generation is limited by (25), while that of a cluster of microgrids is limited by (26). Load shedding is limited by (27). The phase angle of the reference bus is set to zero by (28).

$$\text{Min } \omega_{bht}^s = \sum_m (LS_{mbht}^s) \quad (14)$$

$$\sum_{i \in N_m} P_{ibht}^s + \sum_{l \in N_m} PL_{lbht}^s + \sum_q PM_{qmbht}^s + LS_{mbht}^s = D_{mbht} \quad \forall m \quad (15)$$

$$z_{it} = \hat{z}_{it} \leftrightarrow \lambda_{it}^s \quad \forall i \in CG \quad (16)$$

$$y_{lt} = \hat{y}_{lt} \leftrightarrow \mu_{lt}^s \quad \forall l \in CL \quad (17)$$

$$u_{qmt} = \hat{u}_{qmt} \leftrightarrow \pi_{qmt}^s \quad \forall q \quad (18)$$

$$0 \leq P_{ibht}^s \leq P_i^{\max} UX_{ibht}^s \quad \forall i \in EG \quad (19)$$

$$0 \leq P_{ibht}^s \leq P_i^{\max} UX_{ibht}^s z_{it} \quad \forall i \in CG \quad (20)$$

$$\left| PL_{lbht}^s - \sum_m B_{l,m} \theta_{mbht}^s / x_l \right| \leq M (1 - UY_{lbht}^s) \quad \forall l \in EL \quad (21)$$

$$\left| PL_{lbht}^s \right| \leq PL_l^{\max} UY_{lbht}^s \quad \forall l \in EL \quad (22)$$

$$\left| PL_{lbht}^s - \sum_m B_{l,m} \theta_{mbht}^s / x_l \right| \leq M (1 - UY_{lbht}^s) + M (1 - y_{lt}) \quad (23)$$

$$\forall l \in CL$$

$$\left| PL_{lbht}^s \right| \leq PL_l^{\max} UY_{lbht}^s y_{lt} \quad \forall l \in CL \quad (24)$$

$$0 \leq PM_{qmbht}^s \leq PM_{qmt}^{\max} u_{qmt} \quad \forall q \quad (25)$$

$$\sum_q (PM_{qmbht}^s - PD_{qmbht}^s) \leq 0 \quad \forall m \quad (26)$$

$$0 \leq LS_{mbht}^s \leq PD_{mbht} \quad \forall m \quad (27)$$

$$\theta_{mbht}^s = 0 \quad m = \text{Ref} \quad (28)$$

In the above formulation, the constraints on candidate generating unit, transmission line, and microgrids include the associated binary variables determined in the planning problem. The contingency state of generating units and

transmission lines are included in the set of constraints. The Monte Carlo simulation is applied to model the random outages of generating units and transmission lines [39]-[40]. Moreover, a scenario reduction method is adopted as a tradeoff between the computational burden and the modeling accuracy. An outage in a microgrid will be compensated by adjacent microgrids rather than the main grid. The annual EENS for a system of microgrids is calculated as

$$EENS_t = \sum_h \sum_b \sum_s pr^s DT_{bht} \omega_{bht}^s \quad \forall t \quad (29)$$

If the EENS limit is violated, reliability constraints (30)-(31) are generated and added to the planning problem for promoting investments on new generating units, transmission lines, and microgrids.

$$EENS_t = \sum_h \sum_b \sum_s pr^s DT_{bht} \omega_{bht}^s + \sum_{s \in CG} \sum_{i \in CG} pr^s \lambda_{it}^s (z_{it} - \hat{z}_{it}) + \sum_{s \in CL} \sum_{l \in CL} pr^s \mu_{it}^s (y_{it} - \hat{y}_{it}) + \sum_{s \in q} \sum_{m} pr^s \pi_{qmt}^s (u_{qmt} - \hat{u}_{qmt}) \quad \forall t \quad (30)$$

$$EENS_t \leq EENS_t^{\text{target}} \quad \forall t \quad (31)$$

where λ , μ , and π are dual values of constraints (16)-(18), respectively. In addition, the reliability constraints facilitate the calculation of cost of unserved energy in the planning problem. The iterative procedure will continue until an optimal plan is calculated.

V. NUMERICAL SIMULATIONS OF THE PLANNING PROBLEM

A modified IEEE 118-bus system is used to demonstrate the application of the proposed model for microgrid-based co-optimization of generation and transmission planning. The system has 118 buses, 54 units and 186 branches. The data are given in motor.ece.iit.edu/data/MicrogridPlanning.xls. A set of 16 candidate generating units and 8 candidate transmission lines are considered. Forced outage rates of generating units and transmission lines are 4% and 1%, respectively. A 20-year planning horizon is considered. Each planning year is divided into 12 monthly periods. The monthly load is divided into three load blocks representing off-peak, intermediate and peak loads. The quantity and the duration of load blocks may vary in each period within each year. The planning is performed annually while the operation is carried out for each load block. The VOLL is \$10/kWh and the discount rate is 5%.

There are no limitations on annual investments or the number of microgrids, generating units or transmission lines that could be installed annually. The initial system peak load is 5400 MW with an annual load growth rate of 2.9%. Table I shows annual peak load forecasts. The initial available generation capacity is 5,850 MW. The EENS limit of 150 MWh is considered for the first planning year. The EENS limit is increased 2.9% annually as shown in Table II. The total EENS for the entire planning horizon is limited to 3,990 MWh.

We assume microgrids can be installed at any system buses with an investment cost of \$2000/kW and operation cost of \$1/MWh for microgrids [41]. The Monte Carlo simulation is applied to generate scenarios and simulate random outages of system components. Each possible system state is represented

by a scenario. A uniformly distributed random number from 0 to 1 is sampled for representing the outages of generating units and transmission lines. If the random number is less than the associated forced outage rate, the corresponding generating unit or transmission line is on outage, otherwise it is in service [39]-[40]. The scenario reduction is applied which reduces the number of scenarios from 1000 to 12 and the corresponding probabilities are demonstrated in Table III. The probability metrics based scenario reduction method [39] is applied in this paper. The proposed planning method is implemented on a 2.4-GHz personal computer using CPLEX 11.0 [42].

TABLE I
ANNUAL PEAK LOAD FORECAST

Year	1	2	3	4	5
Peak Load (MW)	4000	4116	4235	4385	4485
Year	6	7	8	9	10
Peak Load (MW)	4615	4748	4886	5028	5174
Year	11	12	13	14	15
Peak Load (MW)	5324	5478	5637	5800	5969
Year	16	17	18	19	20
Peak Load (MW)	6142	6320	6503	6692	6886

TABLE II
ANNUAL EENS LIMIT

Year	1	2	3	4	5
EENS (MWh)	150.00	154.35	158.83	163.43	168.17
Year	6	7	8	9	10
EENS (MWh)	173.05	178.07	183.23	188.54	194.01
Year	11	12	13	14	15
EENS (MWh)	199.64	205.43	211.39	217.52	223.82
Year	16	17	18	19	20
EENS (MWh)	230.31	236.99	243.87	250.94	258.22

TABLE III
PROBABILITIES OF SCENARIOS AFTER SCENARIO REDUCTION

Scenario	1	2	3	4	5	6
Probability	0.6103	0.0330	0.0273	0.0317	0.0497	0.0357
Scenario	7	8	9	10	11	12
Probability	0.0293	0.0250	0.0383	0.0347	0.0430	0.0420

The following cases are studied:

- Case 0:** Base case planning of the main grid generating units
- Case 1:** Co-optimization planning of the main grid generating units and transmission lines
- Case 2:** Co-optimization planning of the main grid generating units with microgrids
- Case 3:** Co-optimization planning of the main grid generating units and transmission lines with microgrids

Case 0: The existing system cannot satisfy the load growth in the planning horizon. The existing generation capacity is larger than the load in years 1-14; however, the system is unable to meet the load and satisfy the reliability requirements together in years 5-20. In years 5-20, the annual EENS limit is violated and additional load shedding is unavoidable. Accordingly, generating units 1-7 and 9-11 are installed by the proposed planning problem to meet the forecasted load. However, the expanded generation capacity does not satisfy system reliability requirements in the subproblems. Although, the original EENS is reduced once the new units are installed, the new EENS would violate the EENS limit in years 5-20. In this case, additional units would violate the EENS limit when the transmission network is congested.

Case 1: The 20-year co-optimization planning of the main grid generation and transmission expansion planning is applied without any microgrid installations. The candidate generating units and transmission lines installation years are shown in Tables IV and V, respectively. The installed generation capacity at the end of the planning horizon is 7,590 MW with a total planning cost of \$4.496B. The total EENS is 862.47 MWh and the cost of unserved energy is \$4M. Load shedding occurs partially at buses 1,4,35,59,60,95 and 117. The load shedding in this case is an economic option that is offered by the planning solution. In this case, the proposed load shedding would replace the installation of candidate units 14-16.

TABLE IV
CANDIDATE UNITS AND INSTALLATION YEARS

Candidate Unit	Bus	Capacity (MW)	Inv. Cost (\$/kW)	Comm. (year)	Case 1	Case 2	Case 3
1	5	200	750	10	14	20	14
2	12	200	750	10	11	16	11
3	25	200	750	10	17	-	-
4	26	200	750	10	20	-	-
5	80	200	750	10	15	20	19
6	89	200	750	10	13	20	20
7	18	100	400	6	19	11	-
8	32	100	400	6	20	15	-
9	55	100	400	6	17	-	-
10	56	100	400	6	19	-	-
11	62	100	400	6	18	-	-
12	78	20	200	3	20	-	-
13	78	20	200	3	20	-	-
14	78	20	200	3	-	-	-
15	95	20	200	3	-	-	-
16	95	20	200	3	-	-	-

TABLE V
CANDIDATE LINES AND INSTALLATION YEARS

Candidate Line	From Bus	To Bus	Capacity (MW)	Inv. Cost (\$/kW)	Comm. (year)	Case 1	Case 2	Case 3
1	8	5	200	267	5	5	-	5
2	11	12	100	196	4	-	-	-
3	26	30	200	860	5	-	-	-
4	38	37	200	375	5	15	-	-
5	77	78	100	124	4	-	-	-
6	94	100	100	580	4	20	-	-
7	99	100	100	813	4	-	-	-
8	17	113	100	301	4	-	-	-

Case 2: The co-optimization planning of microgrids and the main grid generation is considered. Table VI summarizes the total planning cost along with the expected cost of unserved energy. In Case 2, 42 microgrids are installed and a partial load shedding is applied to buses 4,5,9,60, and 82. Table IV shows that the microgrid installations would eliminate the requirement for the installation of generating units 3, 4 and 9-16. The total EENS is 1047.37 MWh which entails to a higher load shedding as compared to that in Case 1. In Case 1, we considered the installation of candidate transmission line 1 which would reduce the congestion on the existing line 4-5, and accordingly reduce the load shedding at bus 4. However in Case 2, a higher total EENS occurs when no microgrid is installed at bus 4. As will be discussed in Case 3, the system will consider the installation of a transmission line in order to reduce EENS.

The total investment cost is increased and the total operation cost is decreased in Case 2 as compared to Case 1. The

proposed microgrid installations will mitigate the congestion on transmission lines 2-12, 23-25 and 84-85. The generation supply by less expensive units will be increased in a less congested grid and the operation cost will be reduced. The installed microgrid capacity at the end of the planning horizon would supply 30% of the associated peak load, which shows that the majority of loads will be satisfied by the main grid generation. In this case, the total planning cost is lowered by 1.36% to \$4.435B as compared to that in Case 1, which suggests that the Case 2 provides a more economical solution with a higher EENS.

Fig. 3 illustrates the total planning cost and the cost of unserved energy as a function of the microgrid capital cost. The microgrid capital cost depends on the type and the location of DER. A less expensive microgrid will result in a higher number of microgrid installations which will reduce the level of load shedding and the cost of unserved energy. In addition, fewer generating units will be installed at the main grid level. A microgrid with a capital cost of \$1000/kW will result in the installation of 5 generating units and 52 microgrids, while a microgrid with a capital cost of \$3000/kW will result in the installation of 9 generating units and 12 microgrids. Fig. 3 illustrates that the investment cost is a decisive factor in microgrid installations, though microgrids will offer low operation costs for supplying local loads. As microgrid investment costs increase, it will be more economical to build a candidate generating unit at the main grid level and/or consider additional load shedding as microgrid installations become inferior.

TABLE VI
SUMMARY OF SYSTEM COSTS (\$BILLION)
(G: GENERATING UNIT, T: TRANSMISSION LINE, M: MICROGRID)

Costs (\$Billion)	Case 1			Case 2			Case 3		
	G	T	M	G	T	M	G	T	M
Investment Cost	0.225	0.052	-	0.062	-	0.435	0.115	0.036	0.221
Operation Cost	4.215	-	-	3.916	-	0.017	4.045	-	0.009
Unserved Energy Cost	0.004			0.005			0.003		
Total Planning Cost	4.496			4.435			4.429

Fig. 3 Cost of planning and unserved energy as a function of microgrid capital cost

In this paper, VOLL is fixed at \$10/kWh at all buses. However, VOLL depends on the types of customers, the amount and the duration of load interruptions, and the time in which the interruption occurs [43]. VOLL, which would impact the unserved energy, would accordingly influence microgrid investments. Fig. 4 illustrates the total planning cost

and the cost of unserved energy as a function of VOLL. Fig. 4 shows that smaller VOLL will result in higher unserved energy. On the other hand, higher VOLL will reduce the system EENS and the cost of unserved energy which corresponds to a higher investment in system planning. Therefore, VOLL will control the expected level of load shedding at each load bus. When VOLL is \$10/kWh, load will be partially curtailed at buses 4,36,59,60,82,93,94. As VOLL increases to \$20/kWh, more microgrids are installed and the load shedding is dropped at buses 36,93,94. When VOLL is \$30/kWh, an additional microgrid is installed at bus 62. So, higher VOLL will results in additional microgrid investments.

Fig. 4 Total planning cost and cost of unserved energy as a function of VOLL

Case 3: A co-optimization expansion planning is considered for the microgrids and the main grid generating units and transmission lines. Table IV shows that only 4 units are installed. Transmission line 1 is installed at year 5 to reduce the congestion on existing line 4-5, enhance generation of unit 1 (at bus 5) and reduce load shedding in bus 4. The low capital cost of this candidate transmission line makes it a more viable investment option as compared to a microgrid installation at bus 4. It is presumed that the microgrids will be installed in a year. As the commissioning time of generating units and transmission lines are large, several microgrids are installed in years 1-4 to reduce the system EENS and meet the system reliability requirements. In this case, a total of 31 microgrids are installed in the planning horizon and transmission line flows are altered as compared to previous cases.

The transmission congestion on lines 4-5, 15-17, 23-25, 84-85 and 17-113 is mitigated. The total planning cost is less by 1.49% as compared to that in Case 1 and 0.13% as compared to that in Case 2. The presented result indicates that higher reliability and economic milestones are attainable in a co-optimization planning of the main grid and microgrids.

The microgrids represent the aggregation of several buses and, as such, can be installed at any main grid regions. In the given system, bus 117 represents a remote bus which is interconnected with the rest of the system through a single transmission line. The annual peak load at this bus in year 1 is 4 MW which increases to 6.88 MW in year 20. The lack of enough generation at this bus, following the line outage, will result in the curtailment of the entire load. The outage of this single line may result in an expected unserved energy of 643.48 MWh (when peak load with probability of 0.042 occurs in a scenario). The load shedding at this bus may be reduced by the installation of either a second transmission line

to connect this bus to the rest of the system or a microgrid at this remote bus location. The first option may feature high installation costs and large commissioning time of the transmission line. Therefore, a microgrid is considered as a quick and efficient solution to this curtailment problem.

Next, we would limit the number of microgrid installations to NQ , where $\sum_m u_{qmt} \leq NQ, \forall t$ in order to provide an insight on a reasonable number of microgrid installations, how microgrid installations would affect the operation and reliability results, and the most suitable buses for microgrid installations, the expansion planning problem. Table VII summarizes the results. The necessary investments on generating units and transmission lines will drop when a higher number of microgrids are installed at proper locations. The locations and the number of microgrids will depend on the maximum number of microgrids that can potentially be installed. The microgrid installations could reduce the annual EENS. However, the total EENS will not change monotonically with the number of installed microgrids. Comparing the load shedding level in Cases 1 and 2 with the number of installed microgrids in Table VII, it is clear that the majority of microgrids are installed at buses where load shedding occurs (i.e., buses 1,35,60,95). There are a few other buses with load shedding (i.e. buses 4,59,82) where microgrids are not ultimately installed. The additional dispatch of generating unit at the main grid level would mitigate the load shedding at these buses. Therefore, microgrids are primarily installed at buses where the load shedding is eminent and local generating units are insufficient to supply the designated load.

TABLE VII
SUMMARY OF MICROGRID INSTALLATIONS

Max. No. of Microgrids	Microgrid Installations	Unit Installations	Line Installations	Total EENS (MWh)
1	60	1-11	1, 4, 6	958
2	35, 95	1-13	1, 4, 6	1209
3	1, 35, 60	1-11	1, 4	862
4	35, 39, 41, 60	1-3, 5-11	1, 4	968
5	35, 39, 41, 45, 60	1-3, 5-11	1, 4	1055
6	1, 35, 39, 41, 60, 83	1-3, 5-7, 9-11	1, 4	526
7	1, 11, 35, 39, 41, 45, 60	1-3, 5-7, 9-11	1, 4	380
8	1, 11, 35, 39, 41, 45, 60, 95	1-3, 5-7, 9-10	1, 4	707
9	1, 11, 35, 39, 41, 45, 60, 88, 95	1, 2, 4-7, 10, 11	1, 4	1208
10	1, 13, 33, 35, 39, 41, 45, 60, 83, 95	1-3, 4-9	1	822

VI. DISCUSSIONS

Microgrids increase the system reliability (by reducing load shedding and enhancing the local controls) and improve the system economics (by reducing system congestion, enhancing the operation of less expensive units, and reducing the need for additional generation and transmission investments). Specific features of the proposed microgrid-based co-optimization

planning of generation and transmission are listed as follows:

- Co-optimization expansion planning: The microgrid-based planning incorporates a co-optimization planning of generation and transmission. The microgrid investment decisions are made as planning alternatives to those of generation and transmission.
- Stochastic Planning Approach: A stochastic approach is applied to the proposed co-optimization planning approach to calculate the system reliability criterion. The stochastic planning employs the Monte Carlo simulation for the modeling of random outages of system components. The stochastic planning approach considers the microgrid as an alternative for enhancing the system reliability when considering the main grid contingencies.
- Enhancements in system operation: The generation and transmission upgrades are subject to large commissioning time and depend on the availability of geographical locations in the main grid; however, microgrids could be installed quickly in any selected system buses, providing a quick and efficient solution to the system reliability requirements.
- Optimal location of microgrids: All system buses are considered as potential options for microgrid installations. Most suitable buses for the installation of microgrids are located at constrained geographical locations which are often subject to hourly load curtailments.
- Economics of microgrids: Despite higher capital investment requirements, microgrids offer economic benefits to power systems. Microgrids could lower the cost of supplying the local loads by reducing the network congestion and enhancing the utilization of less expensive units in power systems.
- Economics of load shedding: A high VOLL in the proposed planning approach would justify the microgrid installation, while for lower VOLLs the economics of load shedding could be comparable with those of a microgrid installation.
- Computational efficiency: Microgrid-based co-optimization planning would include additional binary and continuous variables associated with microgrid investments and operations. In order to reduce the computational burdens, the reliability requirements are examined in annual reliability subproblems as post-processor, which would reduce the size of the microgrid-based planning problem and makes it possible to apply the approach to large-scale planning problems.

VII. CONCLUSIONS

A microgrid-based co-optimization planning model considering the power system reliability and economic criteria was proposed. An efficient formulation of the microgrid installation was proposed, incorporating investment and operation costs of microgrids. The proposed problem considered the annual reliability as a planning criterion. The solution of the planning problem was obtained by minimizing the investment and operation costs of generating units,

transmission lines and microgrids, as well as the cost of unserved energy. The problem utilized the proposed plan to calculate the system annual reliability index and compare it with the targeted EENS value. In the case of violations, reliability constraints were formed and added to the next iteration of the planning problem. The proposed model was analyzed further through numerical simulations, where it was shown that microgrid investments in the power system can provide significant reliability and economic benefits and are viable options for system upgrades when large investments on new generation and transmission facilities are not forthcoming.

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Stochastic Price-based Coordination of Intra-hour Wind Energy and Storage in a Generation Company

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Abstract — This paper develops a day-ahead price-based scheduling strategy for the coordination of wind and storage units in a generating company (GENCO). The proposed strategy is based on the stochastic price-based unit commitment (PBUC) for the scheduling of wind energy and storage units, which considers volatilities in day-ahead intra-hour market prices and wind power generation. The proposed approach firms up the hourly sum of wind and storage unit generation, and mitigate potential wind energy imbalance charges for participating GENCOs in electricity markets. Although the proposed approach would apply to any kind of storage, we consider the pumped-storage hydro (PS) unit as an example in this study. Numerical examples illustrate a GENCO's day-ahead coordinated scheduling results for wind and PS units.

Index Terms — Variable wind power generation, pumped-storage hydro units, GENCOs, Stochastic PBUC, day-ahead market.

NOMENCLATURE

Indices:

h	Index for PS units
k	Index for intra-hour intervals
s	Index for scenarios
t	Index for hourly scheduling periods
w	Index for wind energy units

Functions:

$F_{g,h}$	Water to power conversion function of PS unit h in generation mode
$F_{p,h}$	Water to power conversion function of PS unit h in pump mode

Variables:

$I_{g,h,t}$	Commitment status of PS unit h in generation mode at hour t (binary variable, 0: not in generation mode, 1: in generation mode)
$I_{i,h,t}$	Commitment status of PS unit h in idle mode at hour t (binary variable, 0: not in idle mode, 1: in idle mode)
$I_{p,h,t}$	Commitment status of PS unit h in pump mode at hour t (binary variable, 0: not in pump mode, 1: in pump mode)
$P_{h,t}$	Generation dispatch of PS unit h at hour t (MW)

$P_{C,h,t}$	Coordinated generation dispatch of PS unit h and its coordinated wind energy units at hour t (MW)
$P_{(\cdot),t,k}^s$	Generation dispatch of unit at hour t and intra-hour k in scenario s (MW)
$P_{g,h,t,k}^s$	Generation dispatch of PS unit h in generation mode at hour t and intra-hour k in scenario s (MW)
$P_{p,h,t,k}^s$	Output power of PS unit h in pump mode at hour t and intra-hour k in scenario s (MW)
$P_{w,t}$	Generation dispatch of wind energy unit w at hour t (MW)
$P_{\Delta,(\cdot),t,k}^s$	Power imbalance of unit at hour t and intra-hour k in scenario s (MW)
$P_{\Delta,C,h,t,k}^s$	Deviation of coordinated dispatch of wind-PS at hour t and intra-hour k in scenario s (MW)
$P_{w,t,k}^{c,s}$	Wind power curtailment of wind energy unit w at hour t and intra-hour k in scenario s (MW)
$q_{h,t,k}^s$	Net water flow rate of PS unit h at hour t and intra-hour k in scenario s (Hm ³ /h)
$q_{g,h,t,k}^s$	Water flow rate of PS unit h in generation mode at hour t and intra-hour k in scenario s (Hm ³ /h)
$q_{p,h,t,k}^s$	Water flow rate of PS unit h in pump mode at hour t and intra-hour k in scenario s (Hm ³ /h)
$V_{h,t,k}^s$	Reservoir volume of PS unit h at hour t intra-hour k in scenario s (Hm ³)
$y_{g,h,t}$	Generation startup indicator of PS unit h at hour t
$z_{g,h,t}$	Generation shutdown indicator of PS unit h at hour t
$y_{p,h,t}$	Pumping startup indicator of PS unit h at hour t
$z_{p,h,t}$	Pumping shutdown indicator of PS unit h at hour t
Constants:	
NH	Number of PS units
NK	Number of intra-hour intervals in one hour
NS	Number of scenarios
NT	Number of hours
NW	Number of wind energy units
p^s	Probability of scenario s
$P_{w,t,k}^{f,s}$	Forecasted generation of wind energy unit w at hour t and intra-hour k in scenario s (MW)

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$q_{g,h}^{\max}, q_{g,h}^{\min}$	Max/min water flow rates of PS unit h in generation mode (Hm ³ /h)
$q_{p,h}^{\max}, q_{p,h}^{\min}$	Max/min water flow rates of PS unit h in pump mode (Hm ³ /h)
$RU_{g,h}, RD_{g,h}$	Ramp up/down rate limits of PS unit h in generation mode (MW/h)
$RU_{p,h}, RD_{p,h}$	Ramp up/down rate limits of PS unit h in pump mode (MW/h)
$S_{C,h}$	Set of wind energy units coordinated with PS unit h
$V_h^{\max}, V_h^{\min}$	Max/min reservoir volume of PS unit h (Hm ³)
ρ_{BP}	Energy balancing price (\$/MWh)
$\rho_{DA,t}^s$	Day-ahead energy price at hour t in scenario s (\$/MWh)
$\rho_{DA,t,k}^s$	Day-ahead energy price at hour t and intra-hour k in scenario s (\$/MWh)

I. INTRODUCTION

GENCOs with wind energy units could incur imbalance energy charges in real-time markets due to uninstructed deviations of wind power generation from the day-ahead schedule. In practice, wind energy units participate in day-ahead markets as price takers by offering hourly generation quantities that are based on wind speed forecasts [1].

State-of-the-art forecasting models are able to predict the hourly wind power generation with a mean absolute error in the range of 15–20% of the installed capacity of a wind farm [2]. Such errors may considerably lower the payoff of GENCOs when the scheduled wind power generation cannot be delivered in real-time. Furthermore, the intermittency of wind power generation could make it difficult for wind energy units to take advantage of differences in daily locational marginal prices (LMPs) [3]–[5]. The coordination of energy storage with wind energy is a promising strategy since it not only reduces imbalance energy charges but also improves the dispatchability of wind power generation [6]–[13].

An optimal PS bidding strategy is proposed in [14] which is based on the forecasted market clearing price (MCP) in a competitive electricity market. However, the coordination of energy storage and intermittent wind energy would need to be further addressed. An optimization approach to procure the hourly operation strategy of wind farms located near a small PS generation in a day-ahead energy market is proposed in [15]. In [16], the optimal operation of wind energy unit and PS is investigated from a GENCO's viewpoint considering the volatility of hourly wind power generation and electricity prices in a day-ahead electricity market. The proposed optimization model includes a stochastic analysis of PS and wind power generation in coordinated and uncoordinated schemes. However, the market price volatility and intra-hour fluctuations of wind energy would need to be further addressed [17].

Hourly or intra-hourly variations of load and wind power generation will impose load following and regulation charges

on power systems [18]. Imbalance energy charges imposed on wind energy units would compensate the corresponding load following and regulation charges borne by the power system.

In this paper, we apply the stochastic price based unit commitment (PBUC) to the day-ahead coordinated scheduling of PS and wind energy units in a GENCO [19],[20]. The coordination, depicted in Fig. 1, would firm-up the hourly wind power generation and increase the payoff of wind energy units by mitigating imbalance energy charges. The stochastic PBUC considers day-ahead market price and wind power generation forecast errors in Monte Carlo scenarios. We divide the hourly scheduling period into k intra-hour intervals. The auto-regressive moving average (ARMA) time series is used to simulate the intra-hour wind speed variations [21]. Artificial Neural Network (ANN) is used to represent the intra-hour price forecasts [22].

The rest of this paper is organized as follows. The stochastic PBUC formulation with wind-PS unit coordination is presented in section II. Illustrative example and conclusions are provided in sections III and IV, respectively.

Fig. 1 Coordination of wind energy and PS units

II. STOCHASTIC PBUC FOR WIND-PS UNIT COORDINATION

The PBUC formulation with wind-PS unit coordination is presented in this section as a stochastic optimization problem. In this paper, we assume the forecasts for day-ahead hourly energy prices as well as intra-hourly energy price and wind power generation are available. The wind power generation forecast is procured by incorporating power curve of wind turbine and wind speed time series. The wind speed time series is procured by Markov chain with the probability transition matrix. The probability transition matrix is a square matrix which defines probabilities of transiting from one wind speed category to others. Each wind speed category defines a wind speed range represented by its respective mean value. The probability transition matrix is either constructed by using historical data or by incorporating the characteristics of the probability distribution of the wind speed. Considering the

Weibull distribution function and the autocorrelation factor for the wind speed time series, the probability transition matrix is procured by incorporating an initial probability vector, a weighting matrix and a normalizing vector [23]. Once the probability transition matrix is acquired, Markov chain simulation is used to procure the wind speed time series. In the next step, the diurnal pattern strength is applied to the acquired time series. The diurnal pattern strength which has a sinusoidal form signifies the daily pattern of wind speed. The peak value indicates the ratio of the maximum wind speed to the average wind speed. The wind speed forecast error is further represented by ARMA which is applied to the procured time series [24],[25].

The time series for the market price forecast is procured by using the historical data and ANN. In this paper, the intra-hour (5-min) historical data of the ISO New England is procured [26]. The Monte Carlo simulation method is applied for generating scenarios. The computation burden in the scenario-based optimization is highly dependent on the number of scenarios. The basic idea of scenario reduction is to eliminate low-probability and bundle similar scenarios [27]-[30]. After scenario reduction, each scenario s is associated with a probability p^s . The scenario input to the stochastic PBUC includes the day-ahead hourly energy price, day-ahead intra-hour energy price, and intra-hour wind power generation.

The stochastic optimization is decomposed into a master MIP problem and several linear programming (LP) sub-problems. Once a solution for master problem is procured, the sub-problems check the volume constraints of PS hydro units in scenarios. In case of any violation in scenarios, Benders cuts are generated and fed back to the master problem. The decomposition methodology is shown in Fig. 2.

Fig. 2. Proposed GENCO's Stochastic PBUC solution

The stochastic PBUC formulation with wind-PS unit coordination is represented by (1)-(28). The objective function (1) maximizes the expected payoff of the coordinated wind-PS schedule which is represented in (2), (3). The rest of the

constraints include wind energy unit constraints (4)-(6) and PS unit constraints (7)-(28). The expected day-ahead payoff (1) represents the weighted revenue from day-ahead energy sales based on day-ahead hourly energy prices, day-ahead intra-hourly prices and coordinated wind-PS hourly and intra-hourly schedules.

$$\begin{aligned} \max \sum_{s=1}^{NS} p^s \cdot & \left[\sum_{h=1}^{NH} \sum_{t=1}^{NT} (\rho_{DA,t}^s \cdot P_{C,h,t}) \right] \\ & + p^s \cdot \left[\frac{1}{NK} \sum_{h=1}^{NH} \sum_{t=1}^{NT} \sum_{k=1}^{NK} (\rho_{DA,t,k}^s \cdot P_{\Delta,C,h,t,k}) \right] \\ & - p^s \cdot \left[\frac{1}{NK} \sum_{h=1}^{NH} \sum_{t=1}^{NT} \sum_{k=1}^{NK} \rho_{BP} \cdot P_{\Delta,C,h,t,k} \right] \end{aligned} \quad (1)$$

s.t.

$$P_{C,h,t} = \sum_{w \in S_{C,h}} P_{w,t} + P_{h,t} \quad \forall h, \forall t \quad (2)$$

$$P_{\Delta,C,h,t,k}^s = P_{\Delta,w,t,k}^s + P_{\Delta,h,t,k}^s \quad \forall h, \forall t, \forall k, \forall s, \forall w \in S_{C,h} \quad (3)$$

$$P_{\Delta,w,t,k}^s = P_{w,t,k}^s - P_{w,t} \quad \forall w, \forall t, \forall k, \forall s \quad (4)$$

$$P_{w,t,k}^s = P_{w,t,k}^{f,s} - P_{w,t,k}^{c,s} \quad \forall w, \forall t, \forall k, \forall s \quad (5)$$

$$P_{w,t} \leq \sum_{s=1}^{NS} p^s \cdot \frac{1}{NK} \sum_{k=1}^{NK} P_{w,t,k}^{f,s} \quad \forall w, \forall t, \forall k, \forall s \quad (6)$$

$$P_{h,t,k}^s = P_{g,h,t,k}^s - P_{p,h,t,k}^s \quad \forall h, \forall t, \forall k, \forall s \quad (7)$$

$$P_{\Delta,h,t,k}^s = P_{h,t,k}^s - P_{h,t} \quad \forall h, \forall t, \forall k, \forall s \quad (8)$$

$$P_{g,h,t,k}^s = F_{g,h}(q_{g,h,t,k}^s) \quad \forall h, \forall t, \forall k, \forall s \quad (9)$$

$$P_{p,h,t,k}^s = F_{p,h}(q_{p,h,t,k}^s) \quad \forall h, \forall t, \forall k, \forall s \quad (10)$$

$$-RD_{g,h}/NK \leq P_{g,h,t,(k+1)}^s - P_{g,h,t,k}^s \leq RU_{g,h}/NK \quad \forall h, \forall t, \forall k \in [1, NK-1] \quad (11)$$

$$P_{g,h,t+1,1}^s - P_{g,h,t,NK}^s \leq (RU_{g,h}/NK)(1 - y_{g,h,t+1}) + F(q_{g,h}^{\min}) \cdot y_{g,h,t+1} \quad \forall h, \forall t, \forall s \quad (12)$$

$$(-RD_{g,h}/NK)(1 - z_{g,h,t+1}) - F(q_{g,h}^{\min}) \cdot z_{g,h,t+1} \leq P_{g,h,t+1,1}^s - P_{g,h,t,NK}^s \quad \forall h, \forall t, \forall s \quad (13)$$

$$-RD_{p,h}/NK \leq P_{p,h,t,(k+1)}^s - P_{p,h,t,k}^s \leq RU_{p,h}/NK \quad \forall h, \forall t, \forall k \in [1, NK-1] \quad (14)$$

$$P_{p,h,t+1,1}^s - P_{p,h,t,NK}^s \leq (RU_{p,h}/NK)(1 - y_{p,h,t+1}) + F(q_{p,h}^{\min}) \cdot y_{p,h,t+1} \quad \forall h, \forall t, \forall s \quad (15)$$

$$(-RD_{p,h}/NK)(1 - z_{p,h,t+1}) - F(q_{p,h}^{\min}) \cdot z_{p,h,t+1} \leq P_{p,h,t+1,1}^s - P_{p,h,t,NK}^s \quad \forall h, \forall t, \forall s \quad (16)$$

$$z_{g,h,t} + y_{g,h,t} \leq 1 \quad (17)$$

$$y_{g,h,t} - z_{g,h,t} = I_{g,h,t} - I_{g,h,t-1} \quad (18)$$

$$z_{p,h,t} + y_{p,h,t} \leq 1 \quad (19)$$

$$y_{p,h,t} - z_{p,h,t} = I_{p,h,t} - I_{p,h,t-1} \quad (20)$$

$$q_{h,t,k}^s = q_{g,h,t,k}^s - q_{p,h,t,k}^s \quad \forall h, \forall t, \forall k, \forall s \quad (21)$$

$$q_{g,h}^{\min} \cdot I_{g,h,t} \leq q_{g,h,t,k}^s \leq q_{g,h}^{\max} \cdot I_{g,h,t} \quad \forall h, \forall t, \forall k, \forall s \quad (22)$$

$$q_{p,h}^{\min} \cdot I_{p,h,t} \leq q_{p,h,t,k}^s \leq q_{p,h}^{\max} \cdot I_{p,h,t} \quad \forall h, \forall t, \forall k, \forall s \quad (23)$$

$$I_{g,h,t} + I_{p,h,t} + I_{i,h,t} = 1 \quad \forall h, \forall t \quad (24)$$

$$V_{h,t,k}^s = V_{h,t,k-1}^s - \frac{1}{NK} q_{h,t,k}^s \quad \forall h, \forall t, \forall k \in [2, NK], \forall s \quad (25)$$

$$V_{h,t,1}^s = V_{h,(t-1),NK}^s - \frac{1}{NK} q_{h,t,1}^s \quad \forall h, \forall t, \forall s \quad (26)$$

$$V_h^{\min} \leq V_{h,t,k}^s \leq V_h^{\max} \quad \forall h, \forall t, \forall k, \forall s \quad (27)$$

$$V_{h,0,NK}^s = V_{h,NT,NK}^s \quad \forall h, \forall s \quad (28)$$

The first part in (1) represents the expected day-ahead revenue for the coordinated wind-PS dispatch. The second part represents the incurred expected cost in the day-ahead market based on the day-ahead intra-hour energy price and the deviation of intra-hour wind-PS dispatch from the day-ahead hourly schedule. As shown in (2), the coordinated dispatch is the cumulative dispatch of wind energy and PS units. Here, $P_{C,h,t}$ is the hourly PBUC schedule that a GENCO would submit to the ISO in the day-ahead market. The wind-PS power imbalance is the difference between the day-ahead hourly schedule and the intra-hour output. The GENCO gets paid extra if the intra-hour energy delivery is higher than the hourly day-ahead schedule, and pays to the ISO otherwise. The third term in (1) represents imbalance energy charges for the uninstructed deviation of the coordinated wind-PS power from the hourly day-ahead schedule caused by the intra-hour volatility of wind and PS power generation [31],[32].

As shown in (1), the GENCO pays balancing charges based on the energy balancing price and the absolute value of deviation. Once the energy balancing price is high enough, there would be no deviation from the hourly coordinated schedule of wind-PS units and no imbalance energy charge would incur in the day-ahead market. As shown in the numerical cases, the energy balancing price could play a major role in the GENCO's scheduling decision. Note that, the energy balancing price can be different for excesses and shortages of the scheduled coordinated power. For the sake of simplicity we assume in this paper that the two prices are the same.

In this paper, only the hourly schedule for energy is considered; however, ancillary services could also be included. Moreover, the operation cost of PS units, which include startup and shutdown costs caused by the wear and tear of turbines, are ignored. Note that a PS unit can be coordinated with several wind energy units as shown in (2), where $S_{C,h}$ contains wind energy units coordinated with a PS unit h . Eq. (3) represents the deviation of intra-hour coordinated dispatch of wind-PS from the day-ahead hourly schedule.

Eq. (4) represents the deviation of day-ahead intra-hour wind power generation from the hourly generation schedule. The intra-hourly wind curtailment is represented in (5) where the wind power forecast is a function of forecasted wind speed. The wind power generation is zero when the wind speed is below the cut-in and above the cut-out levels and it is procured by incorporating the wind turbine power curve as the wind speed is between the cut-in and cut-out limits. The actual wind power that is delivered to the power system in scenario s is equal to the Monte Carlo simulated wind power generation

minus the non-negative curtailed wind power. In order to maintain the generation/load balance, the wind power generation may also be curtailed at the ISO's request. The hourly wind power dispatch in (6) is limited by the expected hourly wind power forecast.

Eqs. (7)-(28) represent the PS unit constraints at intra-hour levels. A PS unit has multiple operating modes including generation, pump, and idle. Each mode is modeled as a pseudo unit with ramping up/down rate limits, water balance equations, and reservoir limits. Pseudo units corresponding to the same PS unit are mutually exclusive [20].

Eq. (7) shows that the net intra-hour dispatch of a PS unit is either the power output in the generation mode or the negative of the consumed power in the pump mode. The deviation of intra-hour dispatch from the hourly dispatch is shown in (8). The water to power conversion functions are presented in (9)-(10) for the generation mode and the pump mode, respectively. The ramp up/down constraints for the intra-hour operation are shown in (11)-(20). The net intra-hour water flow rate is defined in (21) as the difference between intra-hour generation and pump flow rates, which are constrained by respective lower and upper flow rates in (22)-(23).

Since the switching between operation modes (i.e., generation, pump, idle) would take time, we assume that a PS unit cannot change its operation mode within the same hour. The intra-hour generation dispatch of a PS unit can vary every 10 minutes but its operation mode must be retained for the entire hour. Eq. (24) shows that the pump, generation, and idle modes are mutually exclusive.

The intra-hour water volume in the PS reservoir shown in (25) is dependent on its previous intra-hour value and the net water flow in the present intra-hour. In particular, the volume in the first intra-hour of each hour shown in (26) is dependent on the volume in the last intra-hour of the previous hour and the present net water flow rate. Here, (25)-(26) represent PS reservoirs with no external flows. This implies that the sum of upstream and downstream reservoir volumes is constant; thus, only one reservoir volume (either the upstream or the downstream) is considered. The volume at each intra-hour is bound to be between min/max values as shown in (27). Eq. (28) imposes volume limits at the beginning and the end of the period. For the sake of simplicity, the initial and the terminal volumes of reservoirs are assumed to be the same in this paper so that the simulation can be performed using the same assumptions for the next day. The hourly constraints for PS unit are included in the formulation by representing the same set of constraints (9), (10) and (21)-(28) and changing the intra-hour indices with the hourly ones.

Eqs. (1)-(28) represent the coordinated wind-PS formulation, which is converted into a master problem with several sub-problems as shown in Fig. 2. The master problem is a mixed-integer linear programming (MILP) optimization problem and the sub-problems are LP problems which are solved by the CPLEX MILP/LP solver. The optimization result is the coordinated wind-PS unit schedule that a GENCO would submit to the ISO. For comparison, we calculate the dispatch of wind and PS units independently (without wind-PS unit coordination). In this case, a GENCO would submit to the

ISO a separate schedule for wind energy and PS units. The stochastic PBUC formulation for PS and wind energy units without wind-PS unit coordination is presented in (29), which maximizes the expected payoff of PS and wind energy units separately subjected to the respective unit constraints.

$$\begin{aligned} \max \sum_{s=1}^{NS} p^s \cdot [& \sum_{w=1}^{NW} \sum_{t=1}^{NT} (\rho_{DA,t}^s \cdot P_{w,t}^s) + \frac{1}{NK} \sum_{w=1}^{NW} \sum_{t=1}^{NT} \sum_{k=1}^{NK} (\rho_{DA,t,k}^s \cdot P_{\Delta,w,t,k}^s) \\ & - \frac{1}{NK} \sum_{w=1}^{NW} \sum_{t=1}^{NT} \sum_{k=1}^{NK} \rho_{BP} \cdot |P_{\Delta,w,t,k}^s| + \sum_{h=1}^{NH} \sum_{t=1}^{NT} (\rho_{DA,t}^s \cdot P_{h,t}^s) \\ & + \frac{1}{NK} \sum_{h=1}^{NH} \sum_{t=1}^{NT} \sum_{k=1}^{NK} (\rho_{DA,t,k}^s \cdot P_{\Delta,h,t,k}^s) - \frac{1}{NK} \sum_{h=1}^{NH} \sum_{t=1}^{NT} \sum_{k=1}^{NK} \rho_{BP} \cdot |P_{\Delta,h,t,k}^s|] \end{aligned} \quad (29)$$

In this formulation, the payoff of wind and PS units are presented as autonomous terms in the objective function. The first part in (29) represents the day-ahead revenue for wind energy unit w . The second part represents the incurred cost in the day-ahead market based on the intra-hour energy price and the deviation of intra-hour wind power from the day-ahead hourly schedule. As shown in (4), the wind power imbalance is the difference between the hourly day-ahead schedule and the actual intra-hour output. Hence, the GENCO gets paid if the intra-hourly energy delivery is higher than the hourly day-ahead schedule, and pays to the ISO otherwise. The third part in (29) represents imbalance energy charges for the uninstructed deviation of delivered wind power from the day-ahead schedule caused by wind power generation variations. As shown, GENCO pays balancing charges based on the energy balancing price and the absolute value of deviation. Similar terms for the PS generation are presented in (29). The objective function is maximized subjected to the constraints (4)-(28) which were presented before.

III. NUMERICAL EXAMPLES

To illustrate the proposed PBUC model, we consider a GENCO that has a single wind energy unit and a single PS unit and participates in the day-ahead energy market. The capacity of the wind energy unit is 150 MW and the operating characteristics of the PS unit are provided in Table I. The input to the proposed model includes the day-ahead hourly and intra-hourly forecasted market price and wind power. The output is the GENCO's coordinated and uncoordinated generation dispatch schedule for wind and PS units.

To consider forecast errors in electricity market prices, we generate 10,000 scenarios using ANN based on the hourly and intra-hourly historical data of energy price in the market [26]. The forecasted wind power is procured by synthesizing wind speed time series and adding the wind speed forecast error using the ARMA method. The forecasted wind power generation is procured by applying the power curve of wind turbine. The 10,000 scenarios are then reduced to 13 scenarios using scenario reduction techniques [29], [30]. The 13 scenarios in 10-minute intra-hour intervals for the forecasted energy price and wind power are depicted in Figs. 3 and 4, respectively. The day-ahead hourly energy price is procured by using the historical data of day-ahead energy prices. The day-ahead hourly forecasted wind power generation is calculated as the expected average intra-hourly wind power generation as indicated on right hand side of (6).

Fig. 3 Forecasted intra-hourly energy price in 13 scenarios

Fig. 4 Forecasted intra-hour wind power generation in 13 scenarios

Four cases are studied in this section. In deterministic Cases 1 and 3, the scenario with highest probability represents the forecasted hourly and intra-hourly energy price and wind power. In stochastic Cases 2 and 4, 13 scenarios are considered for energy price and wind power generation. The considered cases are as follows:

- Case 1: Deterministic solution without any unit coordination
- Case 2: Stochastic solution without any unit coordination
- Case 3: Deterministic solution with wind-PS unit coordination
- Case 4: Stochastic solution with wind-PS unit coordination

TABLE I OPERATING CHARACTERISTICS OF THE PS UNIT		
Generation Mode	Minimum Discharge Rate	0.1 Hm ³ /h
	Maximum Discharge Rate	1.5 Hm ³ /h
	Maximum Power Output	240 MW
	Minimum Power Output	16 MW
Pump Mode	Ramp Up/Down Rate	250 MW/h
	Minimum Discharge Rate	0.1 Hm ³ /h
	Maximum Discharge Rate	1.5 Hm ³ /h
	Maximum Power Output	300 MW
Reservoir Volume	Minimum Power Output	20 MW
	Ramp Up/Down Rate	250 MW/h
	Maximum Volume	20 Hm ³
	Minimum Volume	3 Hm ³

The four Cases are analyzed with respect to the GENCO's payoff, unit commitment, and generation dispatch as follows:

1) Payoff analysis

Table II shows the total payoff, the wind energy unit payoff, and the PS unit payoff for Cases 1 and 3, and expected payoffs for Cases 2 and 4 once the energy balancing prices is 30 \$/MWh. In this table, the imbalance charges incurred in Cases 3 and 4 were divided equally between the wind energy and PS units. Tables III and IV show the impact of energy balancing price in Cases 1-4 on the total payoff. Based on the results given in Tables II-IV, we offer the following observations.

The first observation is that a stochastic model in comparison with the deterministic solution would result in a

lower total payoff and wind energy and PS unit payoffs. For the wind energy unit, if there is no wind-PS coordination and 30 \$/MWh energy balancing price is incurred, the payoff in Case 1 is \$113,580.42 and the expected payoff in the Case 2 is \$92,482.09. The difference between the two payoffs is \$21,098.33. The same comparison is applied to Cases 3 and 4 in which the difference between the stochastic and deterministic payoffs is \$17,958.96.

For the uncoordinated wind energy and PS units, the differences in total payoff are \$28,792.75 and \$27,012.37 in Cases 1-2 and Cases 3-4, which show a 20.6% and 18.9% reduction in the total payoff, respectively. In Table II, The deterministic case represents a perfect forecast (i.e., zero forecast error) which indicates that a more accurate forecast would result in higher payoffs. If the deterministic solution of Case 1 is applied to Case 2; the wind, PS and total payoff are \$91,102.651, \$17,485.763 and \$97,798.822, respectively. The payoffs are higher in Case 2 which indicate the value of stochastic solution. The same applies to Cases 3-4 in which the total payoff in stochastic solution is higher by \$1,702.813.

The second observation is that the payoffs for wind energy and PS units and the wind-PS coordination are higher than those in the non-coordinated strategy. Table II shows the payoffs for wind energy and PS units and wind-PS are increased from Case 1 to Case 3 by 1.4%, 5.3% and 2.1%, respectively. In the stochastic solution, the payoffs for wind energy and PS units and wind-PS coordination are increased from Case 2 to Case 4 by 5.1%, 0.2% and 4.3%, respectively. Here, the coordination can increase the payoff by reducing the intra-hour imbalance charges in the day-ahead market.

TABLE II
EXPECTED PAYOFFS (\$)

Case	Total	Wind Unit	PS Unit
1	139,563.5	113,580.42	25,983.11
2	110,770.8	92,482.10	18,288.68
3	142,568.9	115,192.74	27,376.16
4	115,556.5	97,233.78	18,322.75

The third observation is that, as the energy balancing price increases, imbalance energy charges become more expensive and wind power generation curtailment becomes preferable to avoid higher imbalance energy charges. Wind power generation curtailments reduce the day-ahead generation dispatch and decrease the day-ahead energy revenue. Figs. 5 and 6 show the total payoff and day ahead total sales revenue in Cases 1-4 with respect to energy imbalance charges. The increase in energy balancing price would decrease the day-ahead energy sale revenues when more conservative day-ahead generation schedules are submitted and the total payoff would decrease accordingly.

TABLE III
IMPACT OF ENERGY BALANCING PRICE ON PAYOFFS IN CASE 1

Balancing Price (\$/MWh)	Day Ahead Energy Sale Revenue (\$)	Day Ahead Revenue Adjustment (\$)	DA Imbalance Charge (\$)	Payoff (\$)
0	149,598.75	4,934.05	0	154,532.8
40	145,317.83	-1,781.29	-5,493.97	138,042.6
80	141,718.44	-1,300.58	-6,710.33	133,707.5
120	138,554.00	-890.29	-6,621.07	131,042.6
160	136,701.14	-562.10	-6,974.67	129,164.4

TABLE IV
IMPACT OF ENERGY BALANCING PRICE ON PAYOFFS IN CASE 3

Balancing Price (\$/MWh)	DA Energy Sale Revenue (\$)	DA Revenue Adjustment (\$)	DA Imbalance Charge (\$)	Payoff (\$)
0	149,598.75	4,934.04	0	154,532.8
40	145,417.30	-1,395.75	-2,005.83	142,015.7
80	143,853.97	-889.10	-2,494.40	140,470.5
120	141,823.83	-402.11	-1,669.13	139,752.6
160	139,546.51	0	0	139,546.5

Fig. 5 Total payoff with respect to balancing price

Fig. 6 Day ahead sales revenue with respect to balancing price

Fig. 7 Energy imbalance charges with respect to energy balancing price

The fourth observation is that, as energy balancing prices increase, the wind-PS coordination would result in lower imbalance charges. Comparing Table III and IV, the difference in day-ahead energy imbalance charges is increased between Cases 1 and 3 as the balancing price increases.

In Fig. 7, for energy balancing prices that are less than 20 \$/MWh, the energy imbalance charges in coordinated cases will increase with the energy balancing price. In this case, imbalance charges will be compensated by intra-hour energy sales. For energy balancing prices that are higher than 30 \$/MWh, the wind-PS coordination will decrease the energy imbalance charges.

In Fig. 7, the energy imbalance charge in Case 3 is zero if the energy balancing price reaches 150 \$/MWh; however, the imbalance charges are higher in uncoordinated cases and will reach zero when the energy balancing price is 230\$/MWh. Hence the wind-PS coordination is less susceptible to high energy balancing prices and would decrease the imbalance

charges more rapidly than the uncoordinated operation schemes.

The balancing price plays an important role in determining the day-ahead payoff of a GENCO. The monthly average energy balancing price may become higher than the spot price in certain cases [32],[33]. As energy balancing prices increase, the difference in day-ahead energy sales and intra-hour imbalance charges will increase from Case 1 to Case 3. Once the balancing price is zero, the payoffs in Cases 1 and 3 would become the same; however the payoff in Case 3 is more resilient as energy balancing prices increase.

2) Unit commitment and generation dispatch

The hourly unit commitment for PS is given in Table V. In Cases 1 and 3, the PS unit pumps at hours 1-8 and 23-24 when the energy price is relatively low (see Fig. 3), and generates between hours 9-22 when the energy price is relatively high. Comparing Cases 4 and 2 in which the forecast error is considered, the wind-PS unit coordination would change the unit commitment at hour 22 as shown in Table V. The inclusion of forecast errors may alter the PS unit schedule as shown by comparing Case 3 with Case 4.

In Table V, there is a difference between Cases 3 and 4 at low and high price hours of 9 and 22. In Case 3, the PS unit will generate at those hours while it would switch to pumping in Case 4 to increase the expected payoff.

TABLE V
HOURLY COMMITMENT SCHEDULE OF THE PS UNIT

PS	Hours (1-24)																							
Case 1	-1	-1	-1	-1	-1	-1	-1	-1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	-1	-1
Case 2	-1	-1	-1	-1	-1	-1	-1	-1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	-1	-1
Case 3	-1	-1	-1	-1	-1	-1	-1	-1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	-1	-1
Case 4	-1	-1	-1	-1	-1	-1	-1	-1	1	1	1	1	1	1	1	1	1	1	1	1	1	-1	-1	-1

We offer the following observations which are based on the results presented in Fig. 8 and Table VI.

The first observation is that additional curtailments may be necessary when considering market price and wind speed forecast errors. The wind energy curtailments in Cases 1-4 are 60.554, 140.737, 58.261 and 90.099 MWh, respectively. The stochastic case has a higher wind energy curtailment because a GENCO would be more conservative in submitting the generation schedule as it considers the outcome of different scenarios. Comparing Cases 1 and 3 and Cases 2 and 4 in Fig. 8, it is clear that the coordination will help reduce the wind curtailment once the energy balancing price is increased.

The second observation is that according to Table VI, the scheduled PS dispatch is reduced by 4.47MWh from Case 1 to Case 3 which indicates the effect of wind-PS coordination and the efficiency of PS units in reducing the total dispatched energy. The same notion is applied to the stochastic solution as the PS energy dispatch is reduced by 22.85 MWh from Case 2 to Case 4. The coordination tends to reduce the total generation dispatch. In the deterministic solution, the hourly coordinated dispatch is reduced slightly from 1,870MWh in Case 1 to 1,865MWh in Case 3. The net reduction is caused by a frequent use of the PS unit to compensate the intra-hour variations of wind power generation. The effect is a lower generation because of the difference in water to power

conversion curves of pumping and generation. Also, the coordinated dispatched energy was decreased from 1,923.25 MWh in Case 2 to 1,902.36 MWh in Case 4. However, the payoff was increased by 4.32%.

The third observation is that the scheduled wind power generation is increased in coordinated cases. The total dispatched wind energy in Cases 1-4 are 2,262.53, 2,346.92, 2,262.53 and 2,348.81 MWh respectively. The reduction in the uncoordinated operation is caused by imposing energy balancing price and intra-hour energy price. Note that the energy balancing price is 30\$/MWh in all four cases. The curtailment of wind power generation in Cases 1-4 would increase as the energy balancing price was increased, which would lead to lower payoffs.

Fig. 8 Wind curtailment with respect to energy balancing price

TABLE VI
DAY AHEAD HOURLY WIND AND PS UNIT DISPATCH (MWh)

Hour	Case 1			Case 3		
	Total	Wind	PS	Total	Wind	PS
1	-280.00	20.01	-300	-276.1	20.01	-296.10
2	-259.80	40.20	-300	-257.36	40.2	-297.56
3	-223.65	76.36	-300	-222.57	76.36	-298.92
4	-212.83	87.17	-300	-212.83	87.172	-300
5	-206.32	93.68	-300	-203.41	93.68	-297.09
6	-150.94	107.39	-258.3	-155.22	107.39	-262.61
7	37.310	98.98	-61.67	13.99	98.98	-84.98
8	60.420	80.42	-20	52.57	80.42	-27.85
9	117.46	101.46	16	130.94	101.46	29.48
10	189.81	132.14	57.67	180.26	132.14	48.115
11	262.21	146.17	116	255.13	146.17	108.97
12	349.38	150.00	199.4	338.47	150	188.47
13	307.40	149.69	157.7	296.72	149.69	147.03
14	254.85	138.81	11.04	253.08	138.81	114.27
15	182.11	107.73	74.38	203.35	107.73	95.61
16	152.88	120.17	32.71	171.55	120.17	51.38
17	217.15	142.77	74.38	213.14	142.77	70.37
18	259.90	143.86	116.0	255.12	143.86	111.26
19	341.76	101.76	240	341.76	101.76	240
20	306.43	66.43	240	306.42	66.43	240
21	166.11	51.11	115	175.22	51.11	124.11
22	63.68	47.68	16	67.71	47.68	20.03
23	-31.41	30.26	-61.67	-21.03	30.26	-51.29
24	-34.21	28.29	-62.50	-41.66	28.29	-69.95
Total	1,869.70	2,262.53	-392.8	1,865.26	2,262.53	-397.27

Hour	Case 2			Case 4		
	Total	Wind	PS	Total	Wind	PS
1	-283.47	16.53	-300	-274.828	16.53	-291.36
2	-263.09	36.911	-300	-256.23	36.91	-293.14
3	-223.67	76.327	-300	-218.63	76.33	-294.95
4	-208.14	91.86	-300	-206.24	93.75	-300
5	-198.72	101.28	-300	-198.72	101.28	-300
6	-181.74	118.26	-300	-168.92	118.26	-287.17
7	-63.420	111.58	-175	-54.09	111.58	-165.66
8	29.500	91.17	-61.67	21.68	91.17	-69.49
9	91.910	111.91	-20	84.89	111.91	-27.018

10	152.53	136.53	16	162.19	136.53	25.659
11	202.43	144.77	57.67	248.87	144.77	104.12
12	249.04	149.71	99.33	332.22	149.71	182.51
13	290.95	149.95	141	373.81	149.95	223.85
14	309.8	139.13	170.67	330.17	139.13	191.04
15	243.26	114.26	129	279.96	114.26	165.70
16	241.33	126.33	115	246.74	126.33	120.40
17	298.60	141.94	156.67	254.61	141.94	112.67
18	338.90	140.57	198.33	296.27	140.57	155.7
19	339.1	99.1	240	331.76	99.10	232.66
20	308.2	68.2	240	296.17	68.20	227.97
21	172.77	57.77	115	101.30	57.77	43.52
22	70.595	54.59	16	15.56	54.595	-39.035
23	16.875	36.87	-20	-70.14	36.875	-107.02
24	-10.305	31.36	-41.67	-26.05	31.362	-57.408
Total	1,923.25	2,346.92	-423.6	1,902.36	2,348.81	-446.45

IV. CONCLUSIONS

We proposed a stochastic PBUC solution strategy for the intra-hour coordination of wind-PS units when considering the intra-hour wind energy and market price forecast errors in a GENCO. The numerical example shows the effect of coordination in deterministic and stochastic case studies. The results show that PS units can be coordinated with wind energy units in order to firm up the wind power generation and to take advantage of electricity price volatilities. The imbalance energy charges can reduce a GENCO's expected payoffs which can be fixed by the wind-PS unit coordination. The merits of coordination are more significant as energy balancing price are increased. Thus, the proposed wind-PS unit coordination provides a hedging mechanism to protect GENCOs against wind speed variations. The major contributions of the paper are listed as follows:

- The intra-hour variation of wind power generation is modeled and the PS coordination is proposed to firm the total hourly wind-PS generation.
- The intra-hour variation of energy price is considered for maximizing the GENCO's expected payoff which includes imbalance energy charges and additional intra-hour costs.
- The forecast errors for energy price and wind power are modeled and their impacts on the hourly commitment, generation dispatch, and payoffs are considered.

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Hourly Demand Response in Day-ahead Scheduling for Managing the Variability of Renewable Energy

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Abstract—This paper proposes a stochastic optimization model for the day-ahead scheduling in power systems, which incorporates the hourly demand response (DR) for managing the variability of renewable energy sources (RES). DR considers physical and operating constraints of the hourly demand for economic and reliability responses. The proposed stochastic day-ahead scheduling algorithm considers random outages of system components and forecast errors for hourly loads and RES. The Monte Carlo simulation (MCS) is applied to create stochastic security-constrained unit commitment (SCUC) scenarios for the day-ahead scheduling. A general purpose MILP software is employed to solve the stochastic SCUC problem. Numerical results in the paper demonstrate the benefits of applying DR to the proposed day-ahead scheduling with variable renewable energy sources.

Index Terms - Hourly demand response, day-ahead scheduling, variable renewable energy sources, load forecast errors, network contingencies, stochastic SCUC.

NOMENCLATURE

Parameters:

N_T	Number of time periods
N_G	Number of available generators
N_B	Number of buses
N_D	Number of renewable energy sources
N_J	Number of batteries
N_S	Number of scenarios
t	Index for time periods, $t = 1, 2, \dots, N_T$.
i	Index for generators, $i = 1, 2, \dots, N_G$.
b	Index for buses, $b = 1, 2, \dots, N_B$.
k	Index for renewable sources, $k = 1, 2, \dots, N_D$.
j	Index for batteries, $j = 1, 2, \dots, N_J$.
s	Index for scenarios, $s = 1, 2, \dots, N_S$.
l	Index for available transmission lines
$N_{B,b,t}^D$	Number of blocks of energy demand by bus b at time t
$N_{G,i,t}^G$	Number of blocks of supply bid offered by generator i at time t
P_s	Probability of scenario s
NL_i	No-load cost of generator i , in \$
$\lambda D_{n,b,t}$	Marginal benefit of the n -th block of the bid at bus b and time t , in \$/MW
$\lambda G_{m,i,t}$	Marginal production cost of the m -th block of generator i at time t , in \$/MW
$VOLL_{b,t}$	Value of lost load at bus b at time t , in \$
$RCAP_t$	System reserve requirement at time t , in MW

$P_i^{\max}$	Upper generation limit of unit i , in MW
$\Gamma_{(\cdot)}^{(\cdot)}$	Shift factor
$DR_{b,t}^{\min}$	Minimum curtailed load at bus b and time t , in MW
$DR_{b,t}^{\max}$	Maximum curtailed load at bus b and time t , in MW
$D_{b,t}^{\max}$	Maximum load at but b at time t , in MW
ΔG_i	Maximum ramp up/down rate of generator i , in MW/min
ΔD_b	Pick-up or drop-off rate of load at bus b
$X_{b,t-1}^{on}$	ON time of load at bus b at time $t-1$, in hour
$X_{b,t-1}^{off}$	OFF time of load at bus b at time $t-1$, in hour
UT_b	Minimum ON time of load at bus b , in hour
DT_b	Minimum OFF time of load at bus b , in hour
$E_b^{\max}$	Maximum energy change at but b in the scheduling horizon, in MW
$\underline{q}_j^c$	Minimum charge of storage j , in MW
$\overline{q}_j^c$	Maximum charge of storage j , in MW
$\underline{q}_j^d$	Minimum discharge of storage j , in MW
$\overline{q}_j^d$	Maximum discharge of storage j , in MW
$\underline{e}_j$	Minimum state of storage j , in MW
$\overline{e}_j$	Capacity of storage j , in MW
τ	Reserve responsive time, usually in 10 minute
η	Period span, usually in hour
$\lambda_{(\cdot)}$	Mean time to failure for system component, in hour
$\mu_{(\cdot)}$	Mean time to repair for system component, in hour

Variables:

$d_{n,b,t}^s$	Demand in the n -th block of the stepwise demand bid at bus b at time t in scenario s , in MWh
$p_{m,i,t}^s$	Generation in the m -th block of piecewise linear output by generator i at time t in scenario s , in MW
$S_{i,t}(\cdot)$	Start-up or shut-down cost of unit i at time t , in \$
$X_{i,t}$	Time periods when unit i has been ON or OFF at time t , in hour
$DL_{b,t}^s$	Loss of load at bus b at time t in scenario s , in MW
$p_{i,t}^s$	Dispatch of generator i at time t in scenario s , in MW
$g_{k,t}^s$	Dispatch of renewable source k at time t in scenario s , in MW
$q_{j,t}^s$	Charge (-) or discharge (+) of storage j at time t in scenario s , in MW
$C_{j,t}^s$	State of charge (SOC) of storage j at time t in scenario s , in %
$DE_{b,t}$	Expected price-responsive load at bus b at time t , in MW
$DB_{b,t}^s$	Customer base load at bus b at time t in scenario s , in MW
$DR_{b,t}^s$	Adjustable load of bus b at time t in scenario s , in MW

$RU_{i,t}^s$	Reserve provided by generator i at time t in scenario s , in MW
$RB_{j,t}^s$	Reserve provided by storage j at time t in scenario s , in MW
$z_{i,t}$	Commitment Status of thermal generator i at time t ; 1 for ON and 0 for OFF
$y_{b,t}^s$	State of curtailment at but b at time t in scenario s ; 1 when curtailed and 0 otherwise

I. INTRODUCTION

The hourly demand response (DR) program in electricity markets could provide significant benefits to market participants and customers. Such benefits include lower hourly market prices, lower volatility in hourly market prices, enhanced system reliability, and a smaller chance for the market power exertion by generating companies (GENCO), as customers play a more active role in power system operations. DR offers incentives for lowering electricity usage at times when electricity prices are high or when the power system reliability is in question [1]-[3]. DR becomes more attractive to customers and ISOs as electricity demands, fuel prices, and the quest for achieving a higher system reliability increase.

The DR program includes reliability and economic considerations. In the reliability DR program, participating customers are paid incentives for measured baseline load reductions during contingency conditions [2]. In the economic DR program, participating consumers would curtail hourly loads voluntarily in response to market prices. In this case, customers would shift their less critical hourly loads to periods which would balance potential cost savings against customer inconvenience [4]-[8]. The efficient market dynamics are represented by incorporating both DR programs into the market clearing process.

The integration of renewable energy sources (RES) into power systems could reduce transmission losses and congestion by dispersing power generation, improve the system reliability, defer infrastructure upgrades by the installation of local power supply, reduce carbon footprint by customizing the use of RES, and improve the system efficiency by enhancing the power quality according to customer requirements [9]-[11]. However, the widespread usage of variable RES could be problematic for power system operations [12],[13].

The simulation-based approach is generally applied when considering RES. A set of power production scenarios with their probabilities is introduced to handle uncertainties [14]. The stochastic unit commitment and dispatch with high wind penetration are examined for rolling planning with scenario trees [15]. Rolling planning is carried out for rescheduling which is based on the most up-to-date wind forecasts and existing schedules [16]. A methodology is proposed to determine the required level of spinning and non-spinning reserves with a high penetration of wind power [17]. The Monte Carlo simulation (MCS) method is applied to evaluate the performance of grid-connected wind turbine generators (WTGs) [18],[19]. WTGs are modeled as energy limited units by using a load modification technique [20]. Reliability indices are developed for hybrid solar-wind generation systems [21].

This paper proposes a short-term stochastic SCUC model for day-ahead markets which incorporates a coordinated DR and storage program for managing variable RES, random outages of generating units and transmission lines, and load and wind forecast errors. Both economic and reliability DR programs are considered in the presented DR model. The operating characteristics of loads include stepwise price bids and physical constraints of loads. The scenario reduction is adopted in MCS as a tradeoff between calculation speed and solution accuracy. A general purpose MILP software is employed to solve the stochastic SCUC problem.

The rest of paper is organized as follows. The market clearing mechanism is provided in Section II. The Monte Carlo simulation method for simulating the stochastic SCUC is described in Section III. The mathematical formulation of the stochastic SCUC problem is proposed in Section IV. Numerical testing results are presented and analyzed in Section V. The observation and the concluding remarks are provided in Section VI and Section VII, respectively.

II. PROPOSED MARKET CLEARING MECHANISM

A. Day-ahead Market

The ISO received bids from market participants including load aggregators and DR providers (DRP), and clears the market by optimizing the hourly dispatch of individual generating units over a scheduling horizon. The day-ahead schedule will maximize the social welfare while satisfying system-wide limits and operating constraints of individual market participants.

B. DR Program

In the proposed DR model, loads include the customer base load (CBL) and the price responsive load (PRL). CBL is forecasted based on the historical data; for example, the customer's average electricity usage in the curtailment bid period during the 10 days prior to the day when the bid was submitted [22]. The economic DR may include blocks of hourly PRL bids with corresponding prices. The hourly constraints may include expected price-responsive load, minimum/maximum curtailable load, maximum load pick-up/drop-off rate and minimum up/down time of load curtailment. PRL can be curtailed or shifted to other time periods for economic reasons as scheduled by ISO in the day-ahead market. The proposed model allows customers to participate in reliability DR program. The CBL of participating customers could be curtailed in the case of a system emergency. Customers are required to submit the maximum loss of load and the value of lost load (VOLL) to the DA market and the load curtailment will be scheduled by ISO. Unlike the PRL in economic DR, the loss of load is involuntary [23],[24]. If load shedding occurs, customers will get

compensated equivalent to the amount of lost load multiplied by the corresponding VOLL.

Both DR programs offer operation reserves to the ancillary service market. The energy and reserve markets are scheduled and cleared simultaneously through MILP in the proposed model.

III. MONTE CARLO SIMULATION FOR STOCHASTIC SCUC

The stochastic SCUC in our proposed model includes the following:

A. Renewable Energy Sources

We disregard for simplicity the correlation of load and RES and treated them independently in the scheduling horizon. Suppose the random photovoltaic array (PVA) output follows a Beta distribution and the random WTG output follows a Weibull distribution at each time period [25]. The continuous probability distribution functions (PDFs) are approximated by a discrete distribution. Let PVA_t and WTG_t denote discrete probability distributions for PVA and WTG outputs at time t , respectively. Then:

$$PVA_t = [\{s_t^n, P(s_t^n)\}], \quad n = 1, 2, \dots, NS_t \quad (1)$$

$$WTG_t = [\{w_t^n, P(w_t^n)\}], \quad n = 1, 2, \dots, NW_t \quad (2)$$

where NS_t and NW_t are the total number of discrete output levels in PVA_t and WTG_t , respectively; s_t^n and w_t^n are the n -th discrete levels of PVA and WTG outputs at time stage t , respectively; $P(s_t^n)$ and $P(w_t^n)$ are probabilities of occurrence with respect to s_t^n and w_t^n , which can be calculated based on their probability density functions (PDFs).

We divide the entire scheduling horizon into several time stages in which each stage spans several hours. For each time stage, several scenarios are created based on historical data in which PVA and WTG outputs are different from the corresponding forecasts. The probability of each scenario at each stage is calculated as its weight based on the PDF. The weight for the final-stage scenario is obtained by multiplying corresponding weights along the scenario tree. The stochastic output of PVA or WTG is then represented by possible scenarios with their corresponding probability.

B. Monte Carlo Simulation

The number of samples needed for a given accuracy level is irrelevant to the system size; so the Monte Carlo simulation method is suitable for representing the uncertainty in large-scale optimization problems. MCS includes random outages of generating units and transmission lines [26],[27] as well as CBL forecast errors which represent variations around the forecasts at each time stage. The CBL forecast errors are represented by normal distribution functions in which the mean values are the forecasts and the standard deviations are percentages of the mean values. The outages of generator and transmission line are simulated based on forced outage rates and repair rates [27]. In each scenario, a sampling method [26] is used to determine the 0/1 value of system component availability. Scenario reduction is adopted as a tradeoff between computational burden and modeling accuracy in large-scale DR scheduling problems [28]. The probability metrics based on the scenario reduction method is applied.

IV. STOCHASTIC PROBLEM FORMULATION AND CONSTRAINTS

We assume electricity market participants are independent bidders who bid at their respective marginal costs. ISO calculates the hourly SCUC and DR schedule, and hourly locational marginal prices (LMPs). The problem objective and constraints are formulated as follows:

A. Objective Function

The objective of the proposed SCUC problem is to determine the day-ahead hourly schedule of generating units and hourly DR schedule such that the expected total social welfare is maximized. The social welfare is defined as the sum of consumer surplus and the producer surplus as shown in Fig. 1. The objective function is expressed as follows:

$$\begin{aligned} \max \quad & \sum_{s=1}^{N_S} P_s \{ \sum_{t=1}^{N_T} \sum_{b=1}^{N_B} \sum_{n=1}^{NB_{j,t}^D} \lambda D_{n,b,t} d_{n,b,t}^s \\ & - \sum_{t=1}^{N_T} \sum_{i=1}^{N_G} [\sum_{m=1}^{NB_{i,t}^G} \lambda G_{m,i,t} p_{m,i,t}^s + NL_i z_{i,t} + S_{i,t}(X_{i,t}, z_{i,t})] \\ & - \sum_{t=1}^{N_T} \sum_{b=1}^{N_B} VOLL_{b,t} * DL_{b,t}^s \} \end{aligned} \quad (3)$$

The first term in the objective function (3) is the customer gross surplus and the second term is the generation cost of thermal units, which includes fuel cost, no-load cost, and piecewise linear start-up and shut-down cost. The third term represents the cost of load curtailment. The objective is subject to the following individual scenario constraints.

B. System and Unit Constraints

Constraints (4), (6) and (8) are on power balance, system reserve, and transmission flows, respectively. Constraints (5) and (7)

show unit spinning reserve and line flows, respectively. Other physical constraints of generating units are generating unit limits, ramp rate limits, and min up/down time limits [1],[29],[30].

$$\sum_{i=1}^{N_G} \sum_{m=1}^{NB_{i,t}^G} p_{m,i,t}^s + \sum_{k=1}^{N_D} g_{k,t}^s + \sum_{j=1}^{N_J} q_{j,t}^s - \sum_{b=1}^{N_B} (DE_{b,t} - DR_{b,t}^s) = 0, \forall t, \forall s. \quad (4)$$

$$RU_{i,t}^s = z_{i,t} \cdot \min\{P_i^{\max} - p_{i,t}^s, \Delta G_i \cdot \tau\}, \forall i, \forall t, \forall s. \quad (5)$$

$$\sum_{i=1}^{N_G} RU_{i,t}^s + \sum_{j=1}^{N_J} RB_{j,t}^s + \sum_{b=1}^{N_B} DR_{b,t}^s \geq RCAP_t, \forall t, \forall s. \quad (6)$$

$$F_{l,t}^s = \sum_{i=1}^{N_G} \Gamma_{l,i}^G \sum_{m=1}^{NB_{i,t}^G} p_{m,i,t}^s + \sum_{k=1}^{N_D} \Gamma_{l,k}^D g_{k,t}^s + \sum_{j=1}^{N_J} \Gamma_{l,j}^J q_{j,t}^s - \sum_{b=1}^{N_B} \Gamma_{l,b}^L (DE_{b,t} - DR_{b,t}^s), \forall l, \forall t, \forall s. \quad (7)$$

$$-F_l \leq F_{l,t}^s \leq F_l, \forall l, \forall t, \forall s. \quad (8)$$

Fig. 1. Net social welfare and market equilibrium

Fig. 2. Stepwise demand response bid

C. DR Constraints

Fig. 2 shows a stepwise DR bid in which OA, OC, and OD represent the customer base load, the expected price-responsive load, and the maximum hourly load, respectively. CB and CF are the minimum and maximum load curtailment, respectively. OE denotes the customer load scheduled by ISO in the day-ahead market. Point E (end point of the scheduled load) would be located within two zones of FB and CD as highlighted in Fig. 2. The price-responsive load can be curtailed or shifted to another time period for satisfying system economic or reliability constraints. The ratio of available price-responsive load to the expected price-responsive load is defined as load participation factor (LPF), which is expressed as $LPF = AC / OC$ in Fig. 2. A higher LPF indicates a higher price elasticity of demand and more curtailable loads. $DR_{b,t}^s$ is the adjustable load of bus b at time t in scenario s which is calculated as the difference between the expected price-responsive load and the scheduled load as shown in Fig. 2. Decision variables in the proposed DR model are $DR_{b,t}^s$ and its 0-1 state. $DR_{b,t}^s$ is positive when the load is shifted out from bus b at time t , and negative when the load is shifted to bus b at time t .

The demand response constraints are listed in (9)-(15). The correlation between block demand and total demand is given in (9). The limit on curtailable load is provided in (10), which may either reflect physical load limits or be imposed by ISO. The loss of load constraint is shown in (11), which indicates that loss of load could occur if and only if all price-responsive loads are completely curtailed. Limits on pick-up/drop-off rate of load, min up/down time for load curtailment and allowable change of bus load across schedule horizon are given in (12)-(15), respectively. Constraint (12) would restrict the rate of customer load changes between any two successive hours. Constraint (13) indicates the minimum number of hours that a load would be curtailed. Constraint (14) shows the minimum number of hours when the load would be supplied. Constraint (15) would limit the total number of load curtailments in the scheduling horizon. By setting $E_b^{\max}$ to 0 in (15), the curtailed load at certain time periods will be fully shifted to other periods.

$$\sum_{n=1}^{NB_{j,t}^D} d_{n,b,t}^s = DE_{b,t} - DR_{b,t}^s, \forall b, \forall t, \forall s. \quad (9)$$

$$\begin{cases} DR_{b,t}^{\min} y_{b,t}^s \leq DR_{b,t}^s \leq DR_{b,t}^{\max} y_{b,t}^s, & \text{if } DR_{b,t}^s \geq 0 \\ DR_{b,t}^s \geq DE_{b,t} - D_{b,t}^{\max}, & \text{else} \end{cases} \quad \forall b, \forall t, \forall s. \quad (10)$$

$$DL_{b,t}^s = \max\{DB_{b,t}^s - (DE_{b,t} - DR_{b,t}^s), 0\}, \forall b, \forall t, \forall s. \quad (11)$$

$$|(DE_{b,t} - DR_{b,t}^s) - (DE_{b,t-1} - DR_{b,t-1}^s)| \leq \Delta D_b, \forall b, t = 2, 3, \dots, N_T, \forall s. \quad (12)$$

$$(X_{b,t-1}^{s,on} - UT_b)(y_{b,t-1}^s - y_{b,t}^s) \geq 0, \forall b, t = 2, 3, \dots, N_T, \forall s. \quad (13)$$

$$(X_{b,t-1}^{s,off} - DT_b)(y_{b,t}^s - y_{b,t-1}^s) \geq 0, \forall b, t = 2, 3, \dots, N_T, \forall s. \quad (14)$$

$$0 \leq \sum_{t=1}^{N_T} DR_{b,t}^s \leq E_b^{\max}, \forall b, \forall t, \forall s. \quad (15)$$

D. Storage Constraints

We assume the power system is equipped with a storage with the following constraints: input and output limits of storage, SOC dynamics, SOC limits, initial/final SOC, and reserve contribution of storage are given in (16)-(20), respectively [31]. In (16), $q_{j,t}^s$ is negative when storage is charging, positive when the storage is discharging, and 0 when the storage is not functional. Constraint (20) indicates that reserve provided by storage is the minimum of its existing capacity and the maximum discharge.

$$q_{j,t}^s \in \{0, [-\bar{q}_j^c, -\underline{q}_j^c], [\underline{q}_j^d, \bar{q}_j^d]\}, \forall j, \forall t, \forall s. \quad (16)$$

$$C_{j,t}^s = C_{j,t-1}^s - q_{j,t}^s \cdot \eta / \bar{e}_j, \forall j, \forall t = 2, 3, \dots, N_T, \forall s. \quad (17)$$

$$\underline{C}_j = \frac{\underline{e}_j}{e_j} \leq C_{j,t}^s \leq 1, \forall j, \forall t, \forall s. \quad (18)$$

$$C_{j,0}^s = C_j^0, C_{j,T}^s = C_j^T, \forall j, \forall s. \quad (19)$$

$$RB_{j,t}^s = \tau \cdot \min\{C_{j,t}^s * \bar{e}_j, \bar{q}_j^d\}, \forall j, \forall t, \forall s. \quad (20)$$

Here, (4)-(20) are constraints that are related to individual scenarios. In each scenario, the availability of system components is represented by a set of input parameters in the proposed optimization formulation. For the purpose of presentation, this additional set of variables is not introduced in the SCUC formulation. Thermal units are formulated as non-quick start units with hourly scenario commitments which are the same as those in the base case. However, the dispatch of individual committed thermal units in scenarios could be altered in response to scenario realizations. The final dispatch of a thermal unit is its expected dispatch which is the corresponding weighted average solution of all possible scenarios.

V. NUMERICAL SOLUTION FOR THE PROPOSED PROBLEM

Numerical cases are studied for a modified 6-bus system and a modified IEEE 118-bus system. The MILP model (3)-(20) is solved using the ILOG CPLEX 11.0 [32] in Microsoft Visual C#.NET on an Intel Xeon Server with 64GB RAM. The DR program is implemented at all load buses and curtailed load will be shifted to other periods. The hourly price-responsive loads consist of a single energy block with a bidding price of 20\$/MWh. The system reserve requirement is set as the largest generating unit capacity.

A. The Modified 6-bus System

The modified 6-bus system, shown in Fig. 3, has three thermal units, one WTG, and seven transmission lines. The characteristics of generators, transmission lines and the expected hourly loads are listed in Table I, Tables II and III, respectively.

TABLE I
GENERATORS' DATA FOR 6-BUS SYSTEM

U	Pmax (MW)	Pmin (MW)	Initial Status (h)	Min Down (h)	Min Up (h)	Ramp (MW/h)	λ_i (h)	μ_i (h)
G1	220	100	4	4	4	30	23.6	0.4
G2	100	10	-3	3	2	50	23.7	0.3
G3	20	10	-1	1	1	20	23.8	0.2

TABLE II
TRANSMISSION LINE DATA FOR 6-BUS SYSTEM

Line No.	From Bus	To Bus	X (pu)	Flow Limit (MW)	λ_i (h)	μ_i (h)
1	1	2	0.170	200	23.5	0.5
2	1	4	0.258	100	23.7	0.3
3	2	3	0.037	100	23.6	0.4
4	2	4	0.197	100	23.6	0.4
5	3	6	0.018	100	23.7	0.3
6	4	5	0.037	100	23.6	0.4
7	5	6	0.140	100	23.8	0.2

TABLE III
EXPECTED HOURLY LOAD FOR 6-BUS SYSTEM

H	Load (MWh)	H	Load (MWh)	H	Load (MWh)	H	Load (MWh)
1	175.19	7	168.39	13	242.18	19	245.97
2	165.15	8	177.60	14	243.60	20	237.35
3	158.67	9	186.81	15	248.86	21	237.31
4	154.73	10	206.96	16	255.79	22	215.67
5	155.06	11	228.61	17	256.00	23	185.93

6	160.48	12	236.10	18	246.74	24	195.60
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Fig.3. One line diagram of 6-bus system

Fig 4. Actual and shifted loads

Three cases are studied to illustrate the impact of DR program on the RES variability in the day-ahead scheduling:

Case 1: DR is considered at all load buses.

Case 2: Combined DR and WTG variability is considered.

Case 3: Effect of DR, WTG variability, and storage on hourly LMPs is compared.

These cases are discussed as follows:

Case 1: Economic DR program is considered at all load buses. Fig. 4 shows the hourly system demand with several LPFs. At peak hours, the hourly load profile will be more flat as LPF increases. In Fig. 4, the load profile with LPF=0.3 is almost flat during Hours 6-24, and the standard deviation of hourly load is reduced from 101 MW to 18 MW at 0.3 LPF. A flat load profile corresponds to lower LMPs, lower transmission congestion, and lower system production cost. Also, power system operations will be more efficient since the hourly demand fluctuations are less frequent [2]. We assume a large WTG is located at Bus 5 with its deterministic hourly profile shown in Fig. 5. With a higher LPF, the system load profile will be increasingly close to the WTG profile. In an extreme case, when LPF=0.9, the system load profile would almost match that of WTG in which the peak load is shifted to other hours when the WTG output reaches its peak.

Case 2: In this case, economic DR at all load buses and variable WTG output at Bus 5 are included. The forecasted hourly WTG output is based on <http://www.nrel.gov/>. The 24-hour scheduling horizon is divided into 4 time stages when each time stage spans 6 hours. For each time stage, 5 scenarios including the forecasted output are considered in which the probability of each scenario is calculated according to the PDF of Weibull distribution. For simplicity, the variance is fixed during the horizon. There are $5^4 = 625$ scenarios and each scenario represents a possible WTG output. The scenario reduction method is not applied to this small system. The MCS convergence characteristics for the WTG output and the value of objective function in the 625 scenarios are shown in Fig. 6. The relative error is given as $(1.96 \times S_Y / \sqrt{M}) / \bar{Y} \times 100\%$, where S_Y , M and $\bar{Y}$ are standard deviation, number of scenarios, and expected value of variable Y under 95% confidence interval, respectively. In Fig. 6, the relative error of the total WTG output with 625 simulations is less than 1.5%, while the relative error of objective function is less than 0.2%. Moreover, the relative errors are within 2% after the initial 250 simulations.

Fig. 5 Comparison of WTG output

Fig. 6. Convergence characteristic of MCS

Case 3: In this case, the effects of considering DR, WTG variability, and storage on the hourly LMP are discussed. We study the

following four scenarios in this case:

Scenario 3.1: Base case without considering WTG or DR.

Scenario 3.2: A variable WTG is considered at Bus 5. The MCS with 625 scenarios used in Case 2 is adopted here.

Scenario 3.3: An aggregated and large storage (e.g., pumped storage hydro) located at Bus 5 is added to Scenario 3.2 in order to show explicitly the effect of the storage on hourly LMP profile. The storage parameters are listed in Table IV.

Scenario 3.4: DR is considered at Bus 5 based on Scenario 3.2. For comparison, the upper bound of hourly price-responsive load is set to the maximum charge/discharge in Table IV. The pick-up/drop-off rate limits of loads and the minimum up/down times are not considered for load curtailment.

LMPs at bus 5 in the four scenarios are compared in Fig. 7. Here, the LMPs in Scenario 3.1 spike at Hours 12-21. In Scenario 3.2, the time period is shortened to Hours 14-19. However, the peak-valley difference of LMPs becomes larger due to the WTG variability. The price spike in Scenarios 3.3 is mitigated as the storage shifts peak loads to off-peak hours. Scenario 3.4 shows a smoother LMP profile with 1.20\$/MWh of peak-valley LMP difference by shifting loads to off-peak hours. The LMP fluctuations in Scenario 3.4 are reduced as compared to those in Scenario 3.3. A large storage is less effective than DR in reducing the volatility of hourly LMP because the charging of storage may be limited at off-peak hours. Fig. 8 shows the expected hourly storage output versus the expected LMP in Scenario 3.3. Here, the storage is charging during low LMP hours and discharging when the LMP is high.

TABLE IV
STORAGE DATA FOR 6-BUS SYSTEM

Capacity (MWh)	Max Charge (MW)	Min Charge (MW)	Max Discharge (MW)	Min Discharge (MW)	Initial SOC (%)	Final SOC (%)
300	50	30	50	30	20	20

Fig. 7. LMPs at Bus 5

Fig. 8. Hourly storage charges versus LMP at Bus 5

B. The Modified IEEE 118-Bus System

The IEEE-118 bus system has 54 thermal generators, 186 branches, 91 load buses. The parameters of generators, transmission network, and load profiles are given in [1]. Economic and reliability DR programs at all load buses, random outages of generating unit and transmission lines, load forecast errors, and variable RES, and aggregated storage system are considered. There are 3 RES including 2 WTGs (at Buses 15,54) and 1 PVA (at Bus 96). A storage with parameters listed in Table IV is installed at buses with RES. The hourly WTG forecast is provided at <http://www.nrel.gov/>. VOLL is set at 100\$/MWh. The hourly load forecast error is represented by $\pm 5\%$ of the CBL forecast. We generate 1800 scenarios and reduce the number to 185 by scenario reduction.

Table V lists the results in which EXP is the expected value and RERR is the relative error. Here, the expected average LMP is 19.06 ± 0.23 \$/MWh with a 0.2 LPF and 20% load shedding. Note that the 19.06 ± 0.23 shows that 5% of LMPs will be beyond the given interval of ± 0.23 . The smaller the confidence interval, the more accurate the expectation will be. In spite of high VOLL, the load shedding occurs at certain scenarios with transmission line outages. In such scenarios, the average LMP is much higher than that of the base case. In Table V, the expected average LMP decreases from 19.06 \$/MWh to 18.73 \$/MWh as LPF increases from 0.2 to 0.3. In this case, more operating reserves are made available with a higher LPF. The results suggest that the benefit of larger economic DR is more significant when considering system contingencies. The total CPU time is 6.2 hours when 185 scenarios are applied. The relative errors of operating cost and average LMP are less than 2% as listed in Table V. The relative errors will be smaller and the accuracy will be higher if more scenarios are introduced. In such cases, parallel computation can be further adopted in each scenario to reduce the total CPU time.

TABLE V
DR RESULTS WITH 3 RES (95% CONFIDENCE INTERVAL)

20% Load	LPF=0.2	LPF=0.3
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Shedding	Operating Cost (\$)	Average LMP (\$/MWh)	Operating Cost (\$)	Average LMP (\$/MWh)
EXP	1660250 ± 22937	19.06 ± 0.23	1652905 ± 25193	18.73 ± 0.11
RERR	1.38%	1.21%	1.52%	0.59%

Fig. 9 shows the reduction in operating costs, average LMPs, and load payments as a function of RES contribution, which are compared with the base SCUC (without DR or RES.) In Fig. 9, the reduction in economic metrics increases almost linearly as RES contribution increases. When incorporating a 3.7% RES contribution and a 20% DR, the system operating cost, average LMP and load payment are reduced by 6.93%, 17.77% and 20.71%, respectively. Fig. 10 shows the variation of economic metrics with LPFs when the RES contribution is 3.7%. Comparing Figs. 9 and 10, it is seen DR has a higher impact on the reduction of average LMP and load payment, but RES has a higher impact on the reduction of operating cost. The contribution of DR, RES and storage to the average LMP reduction is shown in Fig. 11. In this case, DR is the leading factor in contributing to the 64.3% reduction in the average LMP, which is followed by those of WTG (18.2%), storage (10.4%) and PVA (7.1%).

Fig. 9. Economic metrics versus RES

Fig. 10. Economic metrics versus LPF

Fig. 11. Contribution percentages to average LMP reduction

Fig. 12. Expected dispatch of WTG at bus 54

TABLE VI
EFFECT OF DR ON WIND ENERGY IN THE SYSTEM

EXP	Without DR	With DR (LPF=0.2)
Total Wind Curtailment (MWh)	6948	4958
Wind Penetration (%)	13.4	17.3

In Fig. 12, WTG curtailments with or without DR at bus 54 are compared. The expected available wind energy in this case is 24,631 MWh, which is 21.7% of the total daily energy demand. The available wind generation represents the upper limit of actual wind dispatch and the difference between the upper limit and the actual dispatch is defined as wind curtailment. In Fig. 12, the available wind generation is dispatched without any curtailment at Hours 1-13, 18 when the hourly available wind generation is below 232 MW. The lightly shaded area in Fig. 12 shows wind curtailment when considering a 20% DR at Bus 54. Here, wind curtailment is higher at Hours 14-17, 19-24 when the available wind generation is higher than 256 MW. The flows on Lines 77 and 78, which connect Buses 54-55 and Buses 54-56, reach their respective limits during those curtailment hours. However, when DR is applied, Bus 54 faces a higher wind curtailment without DR, which is represented by darker shade in Fig. 12. This is because the corresponding load can be shifted between hours. Table VI shows the DR effect on reducing the system wind curtailment. Here, a 20% DR at every load bus would reduce the wind curtailment from 6,948 MWh to 4,958 MWh, while the wind penetration is increased from 13.4% to 17.3%.

VI. OBSERVATIONS

We list the observations below based on our numerical results.

1. Economic DR offers a flat load profile which leads to lower LMPs, lower transmission congestion, and lower system operating cost. Economic DR benefits are more significant when considering system contingencies. Reliability DR provides a chance to maintain the system security.
2. DR has a more significant impact than RES on lowering average LMPs and load payments; RES has a more significant impact than DR on reducing operating costs. DR increases the wind penetration by reducing wind curtailments.
3. The storage system is less effective than DR on lowering the hourly LMP fluctuations which is due to the physical limitation of storage. When compared with RES and storage systems, DR is more effective in reducing average LMPs.

VII. CONCLUSIONS

In this paper, we propose a stochastic optimization model for the day-ahead power system scheduling which incorporates the hourly DR for managing the variability of RES. Physical and operating constraints of hourly demand are considered in DR for economic and reliability responses. The MCS creates multiple scenarios for representing possible realizations of uncertainty. Random outages of system components and forecast errors for hourly load and RES are included in MCS. Numerical results demonstrate that DR offers a flat load profile which leads to lower transmission congestions, lower system operating costs and lower LMPs. In addition, DR is the leading factor for lowering LMPs, which outperforms the utilization of generation resources such as RES and storage. DR increases wind penetration in terms of reducing wind curtailments, which make DR an effective tool for managing the variability of RES.

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Coordination of Short-Term Operation Constraints in Multi-Area Expansion Planning

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Abstract—This paper presents a comprehensive expansion planning algorithm of generation and transmission components in multi-area power systems. The objective is to minimize the total system cost in the planning horizon, comprising investment and operation costs and salvage values subject to long-term system reliability and short-term operation constraints. The multi-area expansion planning problem is decomposed into a planning problem and annual reliability subproblems. The planning decisions calculated in the planning problem would also satisfy the short-term operation constraints. A detailed model of thermal and hydro units is considered using the mixed-integer programming (MIP) formulation. In addition, a multi-state representation for the expansion planning of renewable energy units is explored. The proposed approach considers customers' demand response as an option for reducing the short-term operation costs. The planning problem solution is applied to the annual reliability indices subproblems which examine system reliability indices as a post-processor. If the reliability limit is not satisfied, additional reliability constraints will be introduced which are based on the sensitivity of system reliability index to investment decisions. The new reliability constraints are added to the next iterations of the planning problem to govern the revised plan for the optimal expansion. Numerical simulations indicate the effectiveness of the proposed approach for solving the operation-constrained multi-area expansion planning problem of practical power systems.

Index Terms—Multi-area expansion planning, coordinated transmission and generation expansion planning, coordinated long-term and short-term planning, renewable generation planning, demand response, reliability constraints.

NOMENCLATURE

Indices:

a	Index for area
b	Index for load blocks
f, v	Superscripts for fixed and variable O&M costs
g, p	Superscripts for generating and pumping modes of pumped-storage unit
h	Index for period
i	Index for generating units
l	Index for transmission line

m	Index for bus
n	Index for fuel type
s	Superscript for units in a group
t	Index for year
$\wedge$	Index for calculated variables

Sets:

A	Set of system components in an area
CG	Set of candidate generating units
CH, CT	Set of candidate hydro and thermal units
CL	Set of candidate transmission lines
EG	Set of existing generating units
EH, ET	Set of existing hydro and thermal units
EL	Set of existing transmission lines

Parameters:

B	Bus-line incidence matrix
BL	Bus load percentage
CC	Capital cost
d	Discount rate
DB	Percentage of responsive load
DR	Demand response bid
DT	Duration time
E	Energy limit of pumped-storage unit
EL	Emission limit
EM	Emission rate
FL	Fuel limit
FP	Fuel price
OM	O&M cost
PD	Load demand
r	Unit spinning reserve
R	System spinning reserve requirement
T	Number of years in the scheduling horizon
T^{com}	Commissioning year
T^{Re}	Retirement year
x	Reactance of line
η	Efficiency of pumped-storage unit
κ	Coefficient of present-worth value
γ	Salvage factor
ϑ	Ratio of hours in a load block to the hours in the associated period

Variables:

CU	Curtailed load
F	Fuel function

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I	Commitment state
IC	Total investment cost
$LOLE$	System loss of load expectation
OC	Total operation cost
P	Unit generation
PL	Line flow
PN	Unit generation associated with a specific fuel type
Q^g	Generating power of pumped-storage unit
Q^p	Pumping power of pumped-storage unit
SP	Energy of pumped-storage unit
ST	Stored power of large reservoir unit
SV	Total salvage value
u^g	Generating state of pumped-storage unit
u^p	Pumping state of pumped-storage unit
y	Line investment state
z	Unit investment state
θ	Voltage angle
ξ	Fuel permission state

I. INTRODUCTION

POWER system expansion planning determines the optimal size, time and location of additional generating units and transmission lines for facilitating economic, secure, and reliable operations of a power grid [1]-[3]. Various optimization techniques were considered which shared a common objective: minimize planning and operation costs over the planning horizon. These techniques include mathematical or heuristic approaches to the expansion planning problem [4]-[12].

In the traditional integrated resource planning approaches, a vertically integrated utility would utilize an integrated approach to determine the preferred plan for the installation of new resources. However, the market-based expansion planning considers self-interested participants, coordinates the participants' planning strategies, and analyzes the associated risks based on prevailing uncertainties [13],[14].

In multi-area power systems, the coordination between the generation and transmission expansion planning would become more critical as it could enhance the reliability of individual areas as well as that of the entire system. The transmission cost represents a small portion of the total cost of delivering electricity to multi-area consumers. However, any transmission investment could yield benefits much more than its planning cost in such cases. To encourage the participation in expansion planning opportunities, power market authorities identify long-term demand forecasts, pinpoint potential resource planning alternatives, and demonstrate revenue options for participants in such ventures. The multi-area resource planning proposals are studied and analyzed by the market authorities with respect to cost and reliability for the optimal development of additional generation and transmission capacity in the multi-area expansion planning horizon [15]-[18].

Although market-based planning is applicable to restructured power systems, the coordinated expansion planning of generation and transmission is exercised in many parts of the world. The reasons for utilizing a coordinated approach are

twofold: first, the governments in many countries would still have jurisdictions over power system planning criteria, in which a full privatization in the generation sector is not conceivable and the transmission sector is excluded from any privatization. In other words, the private sector follows tight regulations on generation and transmission planning, and a state entity is overseeing the expansion planning. Second, power systems are often operated and controlled by a single entity in certain countries which are irrespective of individual asset ownerships in the grid. Hence, independent planning decisions are made by market participants who may not have much authority on the daily operation and control of interconnected power systems. The coordinated planning of power systems is exercised primarily for balancing the generation and load, delivering appropriate responses to system events, and preventing unintentional islanding of large interconnections.

A coordinated multi-area expansion planning of transmission and generation components in power systems is proposed in this paper. The approach considers the short-term power system operation strategies in multi-area expansion planning which could reduce the impact of outages, promote affordable and stable market prices, and encourage investments on cleaner and more efficient power plants. A computationally viable approach is developed for considering multi-area system reliability constraints in multi-area expansion planning, where annual reliability subproblems are introduced. The system reliability criterion would be checked in the subproblems and, if not met, additional multi-area reliability constraints are considered and added for revising the power system investment decisions and improving the system reliability to desired levels. The solution of the proposed coordinated model provides annual multi-area plans in the multi-year planning horizon including generation and transmission expansion plans, and advises system planners on the optimal size, location, installation time, and fuel type of new generating units based on transmission limitation, reliability requirements, system operation criteria, and additional economic and environmental constraints.

The proposed multi-area expansion planning algorithm is applicable to both traditional unbundled power systems and the market-based environment. In the market-based environment, the proposed approach is an ISO model which would simulate the interactive coordination of transmission and generation expansion planning [19],[20]. The generation and transmission companies would individually submit their candidate lists of new components to the system operator. It is the responsibility of the system operator to optimally determine appropriate candidates for the least-cost planning while considering long-term reliability and short-term operation constraints. The approach considers the impact of additional renewable energy sources and consumers' hourly demand response on enhancing the long-term planning decisions in multi-area power systems.

The rest of the paper is organized as follows. Section II presents the model outline of the proposed approach, while Section III presents the detailed formulation. Section IV presents illustrative examples to show the proposed model applied to a practical power system. Discussion on the features of the proposed model and concluding remarks are provided in Sections V and VI, respectively.

II. MULTI-AREA EXPANSION PLANNING MODEL

Fig. 1 depicts the proposed multi-area expansion planning model. For large-scale applications, the multi-area expansion planning problem is decomposed into a planning problem and annual reliability subproblems for each year which are treated as a post-processor for the planning problem. The planning problem minimizes the total system cost, comprising planning for new resources and operation costs for the entire system, while considering prevailing unit and system constraints. Planning costs include investment costs and salvage values. Operation costs include fuel costs and operation & maintenance (O&M) costs of thermal, hydro and renewable units.

In Fig. 1, the planning problem is formulated and solved by commercial solvers as an integrated MIP problem. A decomposition could otherwise be applied to reduce the execution time of the proposed planning problem and ensure its applicability to practical systems [18],[21]. The decomposition would separate the planning problem into a master problem, a reliability check subproblem (which checks the transmission network constraints in the proposed plan) and an optimal operation subproblem (which finds the optimal system operation based on the proposed plan). Whenever the reliability or optimality check fails, proper cuts are generated in the corresponding subproblems and added to the next iteration of master problem. This iterative process continues until a secure and optimal expansion planning solution is achieved.

The planning problem finds the least-cost set of candidate generating units and transmission lines to be added to the multi-area system in order to meet load forecasts and satisfy prevailing constraints. Considering the power system operation in the multi-area expansion planning problem, the proposed model provides at each period the solution for generating unit dispatch, capacity factor, fuel consumption, fuel consumption cost, fixed and variable O&M costs, and the cumulative emission level for each unit along with the multi-area network flows.

In Fig. 1, the solution of the planning problem is applied to annual Reliability subproblems for calculating the system reliability index, i.e. loss of load expectation (LOLE). If the stated annual reliability criterion is not satisfied in the subproblems, a reliability constraint based on the sensitivity of LOLE to the current investment decisions is generated and added to the next iteration of the planning problem. This new reliability constraint will govern the investment plan of subsequent iterations to achieve the desired system reliability requirement. The iterative process in Fig. 1 will continue until the reliability criterion is satisfied in the entire planning horizon.

Fig. 1 Proposed multi-area expansion planning model

The multi-area investments are analyzed on an annual basis, i.e. each planned candidate unit or line would be considered for the installation at the beginning of each year. For the system operation, however, every year is decomposed into periods, and each period includes several load blocks. The load duration curve (LDC) method is utilized to consider system load variations and construct load blocks at each period. This long-term option is a practical version of considering hourly chronological loads with an acceptable level of accuracy. The number and the duration of load blocks will represent a tradeoff between the accuracy and the computation burden in the proposed model.

Various types of generators including thermal units (coal, gas, and nuclear), hydro units (run-of-river, large reservoir, and pumped-storage), and renewable units are modeled in this study. Renewable units are modeled as multi-state units to facilitate the system reliability calculation while assuring the modeling accuracy.

The load forecast at every block in every period of the planning horizon will be met by proper multi-area system expansion planning and operation decisions. The system reserve requirements are modeled considering the reserve capability of individual thermal and hydro units.

III. FORMULATION OF MULTI-AREA EXPANSION PLANNING

The proposed multi-area expansion planning minimizes the total system cost throughout the planning horizon (1). The investment cost required for the installation of new generating units and transmission lines is a function of the capital cost (\$/MW) and the available capacity for investment (2). The capacity of individual candidate units and lines is fixed. Operation costs include fuel costs of thermal units, O&M costs of thermal, hydro and renewable units, and demand response of curtailable loads (3). The cost of demand response (i.e., negative generation) is the demand response bid multiplied by the curtailed load, which is paid to consumers for load management. The salvage value (or the residual value) is the future value in terms of percentage of depreciation of the initial investment. In our proposed model, salvage value is the value of installed resource at the end of the planning horizon (4). A higher salvage factor for a commodity indicates a lower depreciation by the end of the planning horizon. The objective is evaluated in terms of discounted costs, in which the discount rate is incorporated in the present-worth value of cost components. A higher discount rate in (5) would affect the investment as resources with higher investment costs become inferior. To calculate the salvage value, κ_t is replaced with κ_T to reflect the commodity value at the end of the planning horizon. T represents the number of planning years.

$$\text{Min } IC + OC - SV \quad (1)$$

$$IC = \sum_t \sum_{i \in CG} \kappa_t CC_i P_i^{\max} (z_{it} - z_{i(t-1)}) \\ + \sum_t \sum_{l \in CL} \kappa_t CC_l PL_l^{\max} (y_{lt} - y_{l(t-1)}) \quad (2)$$

$$OC = \sum_t \sum_h \sum_b \sum_{i \in \{ET, CT\}} \sum_n \kappa_t DT_{bht} F_{it}^n F_{ibht}^n + \sum_t \sum_h \sum_b \sum_i \kappa_t DT_{bht} OM_i^v P_{ibht} + \sum_t \sum_h \sum_b \sum_i \kappa_t OM_i^f P_i^{\max} I_{ibht} \vartheta_b - \sum_t \sum_h \sum_b \sum_m \kappa_t DR_{mht} CU_{mbht} \quad (3)$$

$$SV = \kappa_T \sum_{i \in CG} \gamma_{it} CC_i P_i^{\max} (z_{it} - z_{i(t-1)}) + \kappa_T \sum_{l \in CL} \gamma_{lt} CC_l PL_l^{\max} (y_{lt} - y_{l(t-1)}) \quad (4)$$

$$\kappa_t = \frac{1}{(1+d)^{t-1}} \quad \forall t \quad (5)$$

The proposed multi-area expansion planning objective is subject to the following practical constraints:

A. System Operation Constraints

The load balance constraint (6) requires that the power generated in an area plus the net power injected by transmission lines satisfy the area load minus the curtailed load. The system reserve requirement (7) ensures that the reserve provided by thermal and hydro units satisfies the system spinning reserve requirement. The load curtailment limit (8) ensures that the load curtailment is limited to the designated responsive loads.

$$\sum_{i \in A_a} P_{ibht} + \sum_l B_{a,l} PL_{lbht} = \sum_{m \in A_a} PD_{mbht} - \sum_{m \in A_a} CU_{mbht} \quad (6)$$

$$\forall a, \forall b, \forall h, \forall t$$

$$\sum_{i \in \{ET, CT\}} r_i P_i^{\max} I_{ibht} + \sum_{i \in \{EH, CH\}} (P_i^{\max} - P_{ibht}) I_{ibht} \geq R_{bht} \quad (7)$$

$$\forall b, \forall h, \forall t$$

$$CU_{mbht} \leq DB_{mht} PD_{mbht} \quad \forall m, \forall b, \forall h, \forall t \quad (8)$$

B. Commissioning Time and Installation Constraints

A commissioning time is imposed before any new installations for exchanging the planning information between multi-area system operators and generation and transmission investors. This time is required to obtain necessary approvals on planning and detailed engineering design and construction work, which is dependent on the type and the size of the new installations. A candidate unit or transmission line cannot be installed before its commissioning time is elapsed (9)-(10). Once a candidate generating unit or transmission line is installed, its investment state will be fixed as 1 for the remaining years in the planning horizon (11)-(12). Generating units cannot be committed or dispatched until they are installed (13). A retired generating unit cannot be operated any longer (14).

$$z_{it} = 0 \quad \forall i \in CG, \forall t < T_i^{\text{com}} \quad (9)$$

$$y_{lt} = 0 \quad \forall l \in CL, \forall t < T_l^{\text{com}} \quad (10)$$

$$z_{i(t-1)} \leq z_{it} \quad \forall i \in CG, \forall t \quad (11)$$

$$y_{l(t-1)} \leq y_{lt} \quad \forall l \in CL, \forall t \quad (12)$$

$$I_{ibht} \leq z_{it} \quad \forall i \in CG, \forall b, \forall h, \forall t \quad (13)$$

$$I_{ibht} = 0 \quad \forall i \in EG, \forall b, \forall h, \forall t > T_i^{\text{Re}} \quad (14)$$

C. Thermal Units Constraints

Thermal units are subject to limits on min/max capacity, fuel, emission, and scheduled maintenance. The commitment status of thermal units is considered as part of the min/max capacity limit (15), for an accurate modeling of unit commitment in multi-area power system operations. The proposed multi-area model supports any number of fuel types for new and existing generating units. Thermal units might use alternate or standby fuels as long as the primary fuel is used up. The unit generation dispatch is the sum of its generation by each fuel type (16). Each fuel type would satisfy its min/max limits (17). For the primary fuel, $\xi_{it}^1 = 1$. Likewise, the fuel permission state of the next fuel type would be set to 1 by (18) for switching to the next fuel type. The fuel function of a generating unit is obtained based on min/max heat values and heat rate of the generating unit. The total annual emission of each thermal unit is restricted by (19). Scheduled maintenance would limit the unit commitment and dispatch (20). In addition, group limits are considered which would represent multi-area expansion planning constraints such as total fuel and emission limits of a system (21)-(22).

$$P_i^{\min} I_{ibht} \leq P_{ibht} \leq P_i^{\max} I_{ibht} \quad \forall i \in \{ET, CT\}, \forall b, \forall h, \forall t \quad (15)$$

$$P_{ibht} = \sum_n PN_{ibht}^n \quad \forall i \in \{ET, CT\}, \forall b, \forall h, \forall t \quad (16)$$

$$FL_{it}^{\min} \xi_{it}^n \leq \sum_h \sum_b DT_{bht} F_{ibht}^n \leq FL_{it}^{\max} \xi_{it}^n \quad (17)$$

$$\forall i \in \{ET, CT\}, \forall n, \forall t$$

$$\sum_h \sum_b DT_{bht} F_{ibht}^n \geq FL_{it}^{\max} \xi_{it}^{n+1} \quad \forall i \in \{ET, CT\}, \forall n, \forall t \quad (18)$$

$$\sum_h \sum_b \sum_n EM_i^n DT_{bht} PN_{ibht}^n \leq EL_{it}^{\max} \quad \forall i \in \{ET, CT\}, \forall t \quad (19)$$

$$\sum_h \sum_b DT_{bht} P_{ibht} \leq P_i^{\max} (\sum_h \sum_b DT_{bht} - SM_i * 24) \quad (20)$$

$$\forall i \in \{ET, CT\}, \forall t$$

$$\sum_h \sum_b \sum_{i \in S_n} EM_i^n DT_{bht} PN_{ibht}^n \leq EL_t^{s, \max} \quad \forall t \quad (21)$$

$$FL_t^{s, \min} \leq \sum_h \sum_b \sum_{i \in S_n} DT_{bht} F_{ibht}^n \leq FL_t^{s, \max} \quad \forall t \quad (22)$$

D. Hydro Units Constraints

Three types of hydro units including run-of-river, large reservoirs, and pumped-storage are modeled in our algorithm. For run-of-river hydro units, min/max generation capacity limits and min/max energy limits per period are shown in (23) and (24), respectively. The run-of-river hydro unit has no storage, so $ST_{iht} = 0$.

Existing large reservoir hydro units are modeled by (23)-(27). Similar to run-of-river hydro units, (23) defines min/max capacity limits and (24) defines min/max energy limits available per period. The stored energy is restricted by the reservoir storage capacity (25). The stored energy at various periods is coupled so that the energy is not consumed before it is stored (26). The total stored energy at the end of each planning year is zero (27), i.e. the stored energy annually is converted into generation. For large-reservoir hydro candidate units, (24)-(25) are replaced with (28)-(29) to incorporate the investment variable z_{it} .

$$P_i^{\min} I_{ibht} \leq P_{ibht} \leq P_i^{\max} I_{ibht} \quad \forall i \in \{EH, CH\}, \forall b, \forall h, \forall t \quad (23)$$

$$E_{ih}^{\min} \leq \sum_b DT_{bht} P_{ibht} + ST_{iht} \leq E_{ih}^{\max} \quad \forall i \in EH, \forall h, \forall t \quad (24)$$

$$-ST_{ih}^{\max} \leq ST_{iht} \leq ST_{ih}^{\max} \quad \forall i \in EH, \forall h, \forall t \quad (25)$$

$$0 \leq \sum_{h' < h} ST_{ih't} \leq ST_{ih}^{\max} \quad \forall i \in \{EH, CH\}, \forall h, \forall t \quad (26)$$

$$\sum_h ST_{iht} = 0 \quad \forall i \in \{EH, CH\}, \forall t \quad (27)$$

$$E_{ih}^{\min} z_{it} \leq \sum_b DT_{bht} P_{ibht} + ST_{iht} \leq E_{ih}^{\max} z_{it} \quad \forall i \in CH, \forall h, \forall t \quad (28)$$

$$-ST_{ih}^{\max} z_{it} \leq ST_{iht} \leq ST_{ih}^{\max} z_{it} \quad \forall i \in CH, \forall h, \forall t \quad (29)$$

Pumped-storage hydro units are modeled by (30)-(38). A pumped-storage unit has three operation modes which are generating, pumping, and idling modes. The pumped-storage unit is a load when in pumping mode (30). Generating and pumping modes are subject to min/max capacity limits (31) and (32). At each time point, the unit can only be operated at one of its modes, which is denoted by (33). If $u_{ibht}^p = 1$, the unit is pumping, and if $u_{ibht}^g = 1$, the unit is generating. If both binary variables are zeros, the unit is in idling mode. The constraint is further extended to consider the relationship of operation modes and the investment status of candidate units (34). The stored energy is calculated based on the energy stored at pumping mode minus the energy consumed in the generating mode (35). The stored energy is less than the maximum storage capacity (36). The stored energy in blocks is coupled so that the energy can only be consumed after it is stored (37). The total stored energy by the end of each period is zero (38).

$$P_{ibht} = Q_{ibht}^g - Q_{ibht}^p \quad \forall i \in \{EH, CH\}, \forall b, \forall h, \forall t \quad (30)$$

$$Q_i^{g, \min} u_{ibht}^g \leq Q_{ibht}^g \leq Q_i^{g, \max} u_{ibht}^g \quad \forall i \in \{EH, CH\}, \forall b, \forall h, \forall t \quad (31)$$

$$Q_i^{p, \min} u_{ibht}^p \leq Q_{ibht}^p \leq Q_i^{p, \max} u_{ibht}^p \quad \forall i \in \{EH, CH\}, \forall b, \forall h, \forall t \quad (32)$$

$$u_{ibht}^p + u_{ibht}^g \leq 1 \quad \forall i \in EH, \forall b, \forall h, \forall t \quad (33)$$

$$u_{ibht}^p + u_{ibht}^g \leq z_{it} \quad \forall i \in CH, \forall b, \forall h, \forall t \quad (34)$$

$$SP_{ibht} = \eta_i DT_{bht} Q_{ibht}^p - DT_{bht} Q_{ibht}^g \quad \forall i \in \{EH, CH\}, \forall b, \forall h, \forall t \quad (35)$$

$$-SP_i^{\max} \leq SP_{ibht} \leq SP_i^{\max} \quad \forall i \in \{EH, CH\}, \forall b, \forall h, \forall t \quad (36)$$

$$0 \leq \sum_{b' < b} SP_{ib'ht} \leq SP_i^{\max} \quad \forall i \in \{EH, CH\}, \forall b, \forall h, \forall t \quad (37)$$

$$\sum_b SP_{ibht} = 0 \quad \forall i \in \{EH, CH\}, \forall h, \forall t \quad (38)$$

E. Renewable Unit Constraints

A large integration of intermittent renewable sources could challenge the reliability of multi-area power systems. The significant challenge appears in expansion planning when the additional renewable sources must guarantee a reliable supply of energy to loads [22]. The generation pattern for each renewable unit is determined by its forecasted value. Thus, the

generation value is considered as constant in the load balance equation. Several approaches can be applied to renewable unit generation forecast. For instance, wind speed can be forecasted by historical data or simulated by the Weibull probability distribution function; the generation pattern for wind generating units would then be obtained by applying the wind speed quantity to the power curve of each wind turbine [23].

The renewable energy forecast would also define the pattern for the availability of such units. To consider intermittent units in reliability assessments, their respective generation output should remain above a particular minimum generation level for a specified time period (i.e., persistence time.) A persistence time is assumed for each generation level of a unit. Each minimum generation level is compared to the forecasted renewable generation pattern. The periods are identified in which the forecasted renewable generation is higher than the minimum generation level and continues for at least the persistence time. The sum of all such periods divided by the total generation time for a renewable unit would represent the associated availability of the given generation level. This procedure will be repeated for all generation levels between the min and max generation to determine a generation model for an intermittent generating unit. The renewable unit would be represented as a multi-state unit with a given availability for each state. These states are applied in the reliability calculation using the same method as that for non-intermittent generating units [24].

F. Transmission Network Constraints

The multi-area power system is partitioned into geographical areas, which are connected through transmission lines. The existing line flows are modeled by (39)-(40). For candidate lines, however, the power flow depends on the installation state of the line (41)-(42). If the line is not installed, (41) is relaxed and (42) sets the line flow to zero. Once a line is installed, it will no longer be treated as a candidate line. The voltage angle of the area incorporating slack bus is set to zero (43).

$$PL_{lbt} = \sum_a B_{l,a} \theta_{abht} / x_l \quad \forall l \in EL, \forall b, \forall h, \forall t \quad (39)$$

$$-PL_l^{\max} \leq PL_{lbt} \leq PL_l^{\max} \quad \forall l \in EL, \forall b, \forall h, \forall t \quad (40)$$

$$\left| PL_{lbt} - \sum_a B_{l,a} \theta_{abht} / x_l \right| \leq M(1 - z_{lt}) \quad \forall l \in CL, \forall b, \forall h, \forall t \quad (41)$$

$$|PL_{lbt}| \leq PL_l^{\max} z_{lt} \quad \forall l \in CL, \forall b, \forall h, \forall t \quad (42)$$

$$\theta_{abht} = 0 \quad \forall a = \text{Ref}, \forall b, \forall h, \forall t \quad (43)$$

G. Multi-Area System Reliability Criterion

Once the multi-area expansion planning decisions are made in the planning problem, the new topology with generating unit and transmission line investments is sent to the subproblems where annual LOLEs are calculated as a post-processor. The LOLE calculation utilizes the component forced outage rate [17]. If the system LOLE in a year is larger than the LOLE limit, a reliability constraint is generated in the subproblem and added to the next iteration of the planning problem. The reliability constraint is based on the sensitivity of changes in the system LOLE with respect to changes in each investment decision

(44)-(48).

$$\Delta LOLE_{at} = \sum_{i \in CG} (LOLE_{at,i}^{(1)} - LOLE_{at,i}^{(0)}) \Delta z_{it} + \sum_{l \in CL} (LOLE_{at,l}^{(1)} - LOLE_{at,l}^{(0)}) \Delta y_{lt} \quad \forall a, \forall t \quad (44)$$

$$\Delta z_{it} = z_{it} - \hat{z}_{it} \quad \forall i \in CG, \forall t \quad (45)$$

$$\Delta y_{lt} = y_{lt} - \hat{y}_{lt} \quad \forall l \in CL, \forall t \quad (46)$$

$LOLE_{at,i}^{(1)}$ is for an installed unit i and $LOLE_{at,i}^{(0)}$ is for a candidate generating unit i , which is not installed. Here, $LOLE_{at,i}^{(1)} - LOLE_{at,i}^{(0)}$ represents the incremental change in the LOLE of area a when the investment decision for unit i is changed. Similarly, $LOLE_{at,l}^{(1)} - LOLE_{at,l}^{(0)}$ represents the change in the LOLE of area a when the investment decision for line l is changed. The reliability constraint (47) will be included in the next planning iteration.

$$LOLE_{at} + \Delta LOLE_{at} \leq LOLE_{at}^{\text{target}} \quad \forall a, \forall t \quad (47)$$

IV. NUMERICAL SIMULATIONS

The proposed multi-area expansion planning model is applied to a power system with 43 thermal units, 9 hydro units, and 2 renewable units. The system is partitioned into 7 areas interconnected by 8 tie-lines. Transmission congestion in each single area is ignored.

A set of 23 candidate units (including 16 thermal and 7 hydro units) and 4 candidate lines are considered in Fig. 2. A 20-year planning horizon is considered. Each planning year is divided into six 2-month periods, and six load blocks are considered in each period. Load blocks equally divide the loads between min/max values in each period, and the duration of each block is determined accordingly. The quantity and duration of load blocks may change in each period within each year. The planning is performed annually while the operation is carried out for each load block.

Fig. 2 Multi-area system (C: coal, G: gas, N: nuclear, H: hydro, R: renewable).

In the proposed multi-area model, there are no limitations on annual investments or the number of units and lines that could be installed annually. The discount rate is 5%. The spinning reserve requirement is 5% of the load in each block. The initial multi-area system load is 8,976 MW with an average load growth rate of 2.6%. The initial available generation capacity is 20,430 MW, which decreases due to the retirement of units. By the end of the planning horizon, 11 units will be retired, which reduce the generation capacity to 17,980 MW. LOLE of one day

per year is considered as the reliability criterion in all areas. The proposed multi-area expansion planning method is implemented on a 2.4-GHz personal computer using CPLEX 11.0 [25].

These cases are discussed as follows:

Case 1: The 20-year generation expansion planning is performed in each area without considering any transfer capability among multi-areas. The expansion planning candidates in Tables I and II are intended to ensure an adequate supply of load in each area and satisfy the area reliability criterion. In Case 1, each area in Fig. 2 would supply its own load and satisfy its reliability requirements without any regards to the overall system reliability. As a result, less economical units 4-6 (in area 3) are installed, which result in higher investments and operation costs.

TABLE I
CANDIDATE UNIT INSTALLATION YEAR

Candidate Unit	Type	Area	Capacity (MW)	FOR	Case 1	Case 2	Case 3
1	Gas	3	240	0.04	-	11	11
2	Gas	3	240	0.04	-	6	6
3	Gas	3	240	0.04	-	-	-
4	Gas	3	350	0.04	1	20	-
5	Gas	3	350	0.04	1	-	20
6	Gas	3	350	0.04	1	-	-
7	Gas	4	750	0.04	20	15	15
8	Gas	4	750	0.04	1	15	17
9	Gas	4	750	0.04	3	-	-
10	Coal	1	1000	0.06	-	-	2
11	Coal	1	1000	0.06	-	-	-
12	Coal	1	1000	0.06	1	-	-
13	Nuclear	7	1000	0.04	1	1	1
14	Nuclear	7	1000	0.04	1	1	1
15	Nuclear	7	1000	0.04	-	1	1
16	Nuclear	7	1000	0.04	1	1	1
17	Hydro	6	50	0.01	1	1	1
18	Hydro	6	250	0.01	1	1	1
19	Hydro	6	380	0.01	1	1	1
20	Hydro	6	275	0.01	1	1	1
21	Hydro	6	400	0.01	1	1	1
22	Hydro	6	400	0.01	1	1	1
23	Hydro	6	400	0.01	1	1	1

TABLE II
CANDIDATE LINE INSTALLATION YEAR

Candidate Line	From Area	To Area	Capacity (MW)	FOR	Case 1	Case 2	Case 3
1	1	6	2000	0.002	-	-	4
2	1	3	2000	0.002	-	-	1
3	3	5	2000	0.002	-	-	1
4	2	4	2000	0.002	-	-	-

TABLE III
INSTALLED CAPACITY IN EACH AREA AND THE SYSTEM (MW)

	Case 1	Case 2	Case 3
Area 1	4380	3380	4380
Area 2	4200	4200	4200
Area 3	3450	3230	3230
Area 4	4850	4100	4100
Area 5	2850	2850	2850
Area 6	3705	3705	3705
Area 7	4000	5000	5000
System	27435	26465	27465

The installed area capacity and LOLEs at the end of the planning horizon are shown in Tables III and IV, respectively. The total system cost is \$505.16B and the investment cost is only 4.62% of the total system cost.

TABLE IV
LOLE IN EACH AREA AND THE SYSTEM (DAY/YEAR)

	Case 1	Case 2	Case 3
Area 1	0.00326	0.05431	0.00345
Area 2	0.28790	0.28790	0.28790
Area 3	0.11476	0.68759	0.68759
Area 4	0.00704	0.10360	0.10360
Area 5	0.69304	0.69304	0.68604
Area 6	0.00001	0.00001	0.00001
Area 7	0.64735	0.04164	0.04164
System	-	0.000008	0.0000011

TABLE V
SUMMARY OF SYSTEM COSTS

	Case 1	Case 2	Case 3
Investment Cost (\$Billion)	23.311	21.110	25.517
Operation Cost (\$Billion)	482.275	299.958	289.181
Salvage Value (\$Billion)	0.422	0.402	0.474
Total Planning Cost (\$Billion)	505.164	320.666	314.224

Case 2: A multi-area generation planning model with transmission network constraints is considered. Table IV shows that all areas have met the given reliability criterion. Here, areas with higher levels of reliability would assist those with generation shortfalls. Compared to Case 1, an economical unit is installed at area 7 instead of less economical units at areas 3 and 4. The assisting area 7 would compensate the capacity deficiency in other areas and reduce the overall generation dispatch cost. In Table V, the total system planning cost for investment and operation is \$320.66B, which shows a 36.52% reduction as compared to that in Case 1. Here, both investment and operation costs are reduced.

Case 3: The coordination between the generation and transmission planning is considered in the constrained multi-area power systems. Candidate lines 1, 2 and 3 are installed which would mitigate the congestion in line 1-2 and facilitate the dispatch of economical units in area 1. By installing the candidate line 1, area 1 would also install and utilize the economic unit 10. As a result, area 1 would meet its reliability requirement without any support from area 7 and would also support other areas to compensate their capacity deficiency. Table V shows that the total system cost is \$314.22B, which is 37.80% lower than that of Case 1, and 2.01% lower than that of Case 2. The transmission investment cost in this case is \$2.57B, which represents a small portion of the total cost of multi-area expansion planning. Table V also shows that the proposed solution reduces the operation cost by about \$10.77B as compared with that in Case 2 which yields higher benefits than its investment cost. The annual installed capacity in Cases 1, 2 and 3 are shown in Fig. 3 in which a higher installed capacity is required in Case 1 for maintaining the same level of reliability. The installation of unit 10 in Case 3 would result in a higher installed capacity as compared to that in Case 2; however, the

installation would provide significant economical benefits by low cost power generation.

The effect of renewable sources is further studied by adding 9 candidate wind units to area 4. All candidate wind units are installed at the first year of planning. However, additional non-wind units would be installed to alleviate the intermittency issue of wind units. The additional units may not be economically justifiable; however, they would be required for maintaining the area reliability. The total operation cost after the installation of wind units drops to \$287.83B, which is 8.39% lower than that in Case 3. However, the investment cost increases by 9.34% with the installation of additional thermal units for managing the wind generation intermittency.

Fig. 3 Generation capacity

In Case 3, if the emission constraint on coal units is further considered, more gas units will be installed in the multi-area system. The additional gas units will result in a higher installed capacity and a lower LOLE. Most of the installed gas units are located in area 4 so the candidate line 4 will be installed to mitigate transmission congestion. The installation of gas units will increase the system operation and investment costs, but will lower the emission and facilitate the installation of intermittent wind generating units.

In Cases 1-3, the multi-area expansion planning is performed annually while the operation is carried out for load blocks. There are no limitations on load block durations which could extend from hours to months. The choice will be a tradeoff between the accuracy and the computation time in the proposed model. However, the duration of load blocks could play a key role when considering the short-term system operation. To address this issue in the multi-area expansion planning, annual peak loads are considered in which short-term operation constraints are ignored. In this case, the minimum LOLE requirement in areas 2 and 5 would not be met despite the possibility of receiving assistance from other areas and considering additional generating unit installations. The investment cost of generating units would be 6.67% higher when the short-term operation constraints are not considered.

Case 4: Gas-fired generating units have become favorable commodities in power systems because of their economic benefits, operation flexibility, and low environmental impacts. Gas-fired units provide a linkage between natural gas and electric power systems. Therefore, limitations on natural gas supply might affect power system operations. To consider the

interdependency of gas and electricity, an annual gas supply limit of 150 mmscfd is considered in this case. Here, gas supply in years 2 and 3 (164.88 and 213.14 mmscfd, respectively) is insufficient which is compensated by coal units. All the candidate lines are installed to enhance the coal unit dispatch located in area 1. The total system cost is 0.66% higher than that in Case 3 which is due to the installation of more expensive coal units.

V. DISCUSSIONS

The specific features of the proposed multi-area expansion planning model are listed as follows:

- Lower investment costs: Fewer units are to be installed for reliability requirements because the interconnected areas would maintain a desired level of reliability in the multi-area system.
- Lower operation costs: The interconnected areas would facilitate the economic transfer of low cost generation to areas with higher load demands.
- Accurate models: Load blocks are used for load modeling (instead of peak loads), and comprehensive models are considered for generating units and transmission lines in the short-term system operation.
- Practical results: The multi-area generation and transmission coordination is considered in operation and planning stages. Moreover, reliability requirements are considered based on random outages of generating units and transmission lines.
- Computation efficiency: The reliability requirements are incorporated in the multi-area expansion planning model by introducing annual reliability subproblems in Fig. 1. The proposed decomposition will reduce the size of the coordinated problem and add minute computation burdens to the multi-area expansion planning problem.

VI. CONCLUSIONS

An efficient and comprehensive multi-area model for the coordinated expansion planning with the consideration of system reliability constraints was proposed. The multi-area expansion planning problem was decomposed into a planning problem and annual reliability subproblems for each year. The planning problem found the expansion plan by considering candidate units and lines. The subproblems utilized the proposed plan to calculate the system annual reliability index and compared it to the target value. In case of violations, reliability constraints were formed and added to the next iteration of the planning problem. A complete formulation of this multi-area model was presented, incorporating models for thermal, hydro and renewable units, along with a multi-area transmission network, so that the readers can replicate the model. The proposed multi-area model was analyzed further through numerical simulations, where it was shown that the solution of the coordinated multi-area expansion planning is applicable to practical power systems. The coordinated multi-area expansion planning enhanced the solutions by considering the impact of transmission constraints on system adequacy and reliability, and further guaranteed a reliable and

optimal solution.

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Allocation of Hourly Reserve versus Demand Response for Security-Constrained Scheduling of Stochastic Wind Energy

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Abstract—This paper presents a stochastic method for the hourly scheduling of optimal reserves when the hourly forecast errors of wind energy and load are considered. The approach utilizes the stochastic security-constrained unit commitment (SCUC) model and a two-stage stochastic programming for the day-ahead scheduling of wind energy and conventional units with N-1 contingencies. The effect of aggregated hourly demand (DR) response is considered as a means of mitigating transmission violations when uncertainties are considered. The proposed mixed-integer programming (MIP) model applies the Monte Carlo method for representing the hourly wind energy and system load forecast errors. A 6-bus, 118-bus, and the Northwest region of Turkish electric power network are considered to demonstrate the effectiveness of the proposed day-ahead stochastic scheduling method in power systems.

Index Terms— Stochastic security-constrained unit commitment, wind energy, hourly reserves, demand response, load and wind forecast errors, random contingencies.

NOMENCLATURE

Indices:

d	Index of load
i	Index of non-wind energy generating units
r	Index of DRPs
s	Index of scenarios
t	Index of time period (hour)
k	Index of DR provider bid segments
w	Index of wind energy units

Dimensions:

NC	Number of $N-1$ contingencies
ND	Number of system loads
NDR	Number of DRPs
NG	Number of non-wind generating units
NS	Total number of scenarios including contingencies and wind, load forecast error scenarios
NT	Number of hours
NQ_r	Number of bidding segments
NW	Number of wind energy units

Constraints:

C_{net}	Generalized network constraints in base case and wind, load scenarios
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Variables:

$C_{DRR,r}$	Cost of scheduling DRR by DRP r
$C_{EDRR,r}$	Cost of utilizing scheduled DRR by DRP r
DRR_{rt}	Scheduled DR by DRP r at time t

DRR_{rts}	Deployed DR by DRP r at time t in scenario s
$F_{c,i}$	Bid-based energy cost function of unit i
$F_{RR,i}$	Bid-based cost function of unit i regulation reserve
$F_{SR,i}$	Bid-based cost function of unit i spinning reserve
I	Commitment state
P	Power generation
P_{IMB}	Power generation in regulation interval
$P_{\Psi,wts}$	Wind generation of unit w at time t and scenario s
$P_{curt,wts}$	Curtailed wind generation of unit w at time t and scenario s
RR	Regulation reserve
RR_d	Scheduled regulation-down reserve
RR_{its}	Deployed regulation reserve of unit i at time t in scenario s
RR_u	Scheduled regulation-up reserve
SR	Deployed spinning reserve
SR_d	Scheduled spinning-down reserve
SR_{its}	Deployed spinning reserve by unit i at time t in scenario s
SR_u	Scheduled spinning-up reserve
SD	Shutdown cost
SU	Startup cost
u_{rts}^k	Binary variable (1 if point k of offer package DRP r at time t in scenario s is utilized, 0 otherwise)
U_{rt}^k	Binary variable (takes the value 1 if point k of offer package DRP r at time t is scheduled, 0 otherwise)
y_{it}	Startup indicator (1 if unit i is started up at time t)
z_{it}	Shut down indicator (1 if unit i is shut down at time t)
ψ_{wts}	Speed of wind energy unit w at hour t in scenario s

Constants:

A_w	Area swept by the rotor of wind energy unit w
$c_{p,w}$	Power coefficient of wind energy unit w
cc_{rt}^k	Scheduling cost of point k of offer package DRP r at time t
$C_{curt,wts}$	Cost of 1MWh wind power curtailment from wind generator w at time t
DR	Ramp down limit
ec_{rt}^k	Deployment cost of point k of scheduled offer by DRP r at time t
l_d	Involuntary load shedding at load d
MD_i	Minimum down time for unit i
MU_i	Minimum up time for unit i

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p_s	Probability of scenario s of wind and load uncertainty
$P_{D,d}$	Power demand at load d
P_{max}	Maximum power generation of unit i
P_{min}	Minimum power generation of unit i
q_r^k	k th discrete DRR value of the bid of DRP r
$\rho_{air,w}$	Air density at region where wind unit w is located
$\rho_{\alpha,i}$	Capacity cost of reserve type α for unit i
TD_{i0}	Number of hours unit i has been offline initially
TU_{i0}	Number of hours unit i has been online initially
$v_{CI,w}$	Cut-in wind speed of wind energy unit w
$v_{CO,w}$	Cut-out wind speed of wind energy unit w
$v_{R,w}$	Rated wind speed of wind energy unit w
$VOLL_d$	Value of lost load at load d
UR	Ramp up limit
Δ_s	Allowed system load imbalance for the $N-1$ contingency in scenario s

Abbreviations:

<i>DR</i>	Demand Response
<i>DRR</i>	Demand Response Reserve
<i>DRP</i>	Demand Response Provider

I. INTRODUCTION

As the renewable energy integration in power systems evolves, the cost of supplying ancillary services becomes more prevalent with respect to operating decisions [1]. Wind energy is the fastest growing type of renewable energy due to its clean and indigenous nature. On the other hand, the installed wind capacity is not readily dispatchable due to its intermittent nature [2]-[7]. The effect of wind energy forecast errors is considered in the network-constrained market-clearing problem using a two-stage stochastic programming model in [8]. The first contribution of this paper is that it calculates the hourly reserves for addressing load and wind energy forecast errors in a stochastic framework while considering $N-1$ contingencies in power networks.

DR is a tariff that would encourage lower electricity consumptions [9]-[11]. DR can be motivated by either providing end-users with time-varying rates or giving incentives to such costumers to reduce loads at times when the electricity market price is high or the system reliability is at stake. The time-varying rates require an advanced measurement and communication infrastructure in order to convey real-time prices to end-use consumers, while the incentives are more suitable for a faster adaptation of electricity markets. DR provides financial incentives to customers who also benefit from lower hourly demands [12]-[16]. The second contribution of this paper would model the hourly DR in a discrete form in order to reflect the market behavior in an uncertain environment.

We propose a stochastic model in which wind and load forecast errors are addressed through Monte-Carlo based scenarios in a two-stage stochastic programming model. The component outages are considered in an $N-1$ contingency model. To address the computation complexity, the problem is

decomposed into a master problem to solve the UC and reserve schedules, and subproblems for considering the network security, for pre-selected $N-1$ contingencies, and load and wind forecast error scenarios. At the same time, DR is considered for managing hourly violations and reducing the cost of supplying the load. Load shedding is utilized whenever its contribution to lowering the stochastic cost is higher than that of allocating additional generating reserves. The proposed method would be used by an ISO or a vertical integrated utility to address the stochastic cost of security. The stochastic cost of security is defined as the difference between the scheduling cost of deterministic SCUC and that of considering uncertainties.

The rest of the paper is organized as follows. Mathematical models of DR and simulation of wind and load forecast error are discussed in Section II. The energy and A/S market clearing problem is introduced in Section III. Case studies are given in Section IV. Section V concludes this paper.

II. DR, LOAD, AND WIND ENERGY MODELS

A. Demand Response Model

Demand response is formulated using a MIP formulation to fit the SCUC model. The bid should be in a discrete form since the DRP (demand response provider) represents an aggregated DR of end-users. (1)-(2) in the following represent the scheduled demand response reserve (DRR) of DRP r at the time interval t and the related capacity cost. The value of q_r^0 would be greater than the minimum amount determined by the ISO. (3)-(4) give the actual DRR utilized by DRP r in scenario s at time t , and the associated energy cost. A graphical representation of (1)-(5) is given in Fig. 1.

$$DRR_{rt} = q_r^0 U_{rt}^0 + \sum_{k=1}^{NQ_r} \lambda_r^k U_{rt}^k \quad \forall r, \forall t \quad (1)$$

$$C_{DRR,rt} = cc_{rt}^0 q_r^0 U_{rt}^0 + \sum_{k=1}^{NQ_r} cc_{rt}^k \lambda_r^k U_{rt}^k \quad \forall r, \forall t \quad (2)$$

$$DRR_{rts} = q_r^0 u_{rts}^0 + \sum_{k=1}^{NQ_r} \lambda_r^k u_{rts}^k \quad \forall r, \forall t, \forall s \quad (3)$$

$$C_{EDRR,rts} = ec_{rt}^0 q_r^0 u_{rts}^0 + \sum_{k=1}^{NQ_r} ec_{rt}^k \lambda_r^k u_{rts}^k \quad \forall r, \forall t, \forall s \quad (4)$$

$$\lambda_r^k = q_r^k - q_r^{k-1} \quad \forall r \quad (5)$$

In Fig. 1, "x" denotes a schedule k (i.e., $U_{rt}^0, U_{rt}^1, U_{rt}^2, U_{rt}^3=1$, and $U_{rt}^4=0$), and "+" denotes the discrete DR offer k deployed in scenario s (i.e. $u_{rts}^0, u_{rts}^1=1$ and $u_{rts}^2, u_{rts}^3, u_{rts}^4=0$).

Fig. 1. Discrete DR bid scheduling and deployment

B. Wind Energy and Load Simulation

This section discusses the modeling of forecast error scenarios for wind energy and system load which will be used in Monte Carlo simulations. The nonlinear wind speed to power conversion curve is given in (6) and $P_{\psi, wts}$ is given as an input to the algorithm. The wind power generation w is subject to (7):

$$P_{\psi, wts}(\psi_{wts}) = \begin{cases} 0 & \text{if } \psi_{wts} < v_{cl, w} \\ 0.5 c_{p, w} \cdot \rho_{air, w} \cdot A_w \cdot (\psi_{wts})^3 & \text{if } v_{cl, w} \leq \psi_{wts} < v_{R, w} \\ P_{R, w} & \text{if } v_{R, w} \leq \psi_{wts} < v_{CO, w} \\ 0 & \text{if } \psi_{wts} \geq v_{CO, w} \end{cases} \quad \forall w, \forall s \quad (6)$$

$$I_{wts} \cdot P_{min, w} \leq P_{wts} \leq I_{wts} \cdot P_{\psi, wts}(\psi_{wts}) \quad \forall k, \forall s \quad (7)$$

The auto-regressive moving average (ARMA) based approach [17] provides scenarios for representing wind energy forecast errors. The wind energy forecast errors are simulated using ARMA series. The obtained ARMA series is sampled in order to obtain the forecast errors at each time step t in each scenario s . The corresponding available wind power is obtained via (6). The system load forecast error at time t is subject to a normal distribution $N(P_{D,t0}, \sigma^2)$, where $P_{D,t0}$ is the forecasted system load at time t and σ is the load volatility. The system load distribution is sampled for scenario s at time t . The autocorrelation of the load forecast error model is assumed to be zero. The wind and load uncertainties are assumed independent.

III. SECURITY-CONSTRAINED WIND ENERGY SCHEDULING

A. Objective Function

SCUC is modeled as an optimization problem for calculating the hourly unit commitment schedule at minimum production cost without compromising the system reliability. The regulation reserve is considered for following the short-term variations in the hourly customer demand or the scheduled generation, in order to maintain the system frequency within a permissible range. Spinning reserve is the unloaded generating capacity that can ramp up/down in 10 minutes. DR is assumed to be in the class of spinning reserves [1]. There are four terms in the SCUC objective function (8).

$$\begin{aligned} \min \sum_{t=1}^{NT} & \left\{ \sum_{i=1}^{NG} \left[F_{c,i}(P_{it0}) + F_{RR,i}(RR_{u,it}) + F_{RR,i}(RR_{d,it}) + F_{SR,i}(SR_{u,it}) + F_{SR,i}(SR_{d,it}) + SU_{it} + SD_{it} \right] \right. \\ & + \sum_{r=1}^{NDR} C_{DRR,rt} + \sum_{w=1}^{NW} P_{curt,wt0} \cdot c_{curt,wt0} \\ & \left. + \sum_{s=NC+1}^{NS} P_s \left\{ \sum_{r=1}^{NDR} C_{EDRR,rt} + \sum_{d=1}^{ND} VOLL_d \cdot I_{dts} + \sum_{w=1}^{NW} P_{curt,wts} \cdot c_{curt,wts} \right\} \right\} \quad (8) \end{aligned}$$

The first term is composed of base case generation and reserve costs, and startup and shutdown costs. The second term is the capacity allocation cost corresponding to demand response. The third term is the cost of base case wind energy curtailment. The last term is the expected cost of deployment of regulation and spinning reserves, cost of deployment of DR reserves, cost of involuntary load shedding, and cost of wind curtailment for wind and load forecast scenarios. The scenarios $s=1$ to NC represent $N-1$ contingencies and $s=NC+1$ to NS represent the wind and load forecast error scenarios.

We use a two-stage stochastic programming with recourse [18] in which the first stage variables are commitment states (I_{it}), base case generations (P_{it0}, P_{wt0}), wind curtailments ($c_{curt,wt0}$), and scheduled regulation and spinning reserves ($RR_{u,it}, RR_{d,it}, SR_{u,it}, SR_{d,it}$), and DRPs at hour t (DRR_{rt}). The second stage variables are scenario power generations ($P_{IMB,its}, P_{its}, P_{wts}$), deployed regulation and spinning reserves (RR_{its}, SR_{its}) and deployed DRPs (DRR_{rts}), wind curtailments ($c_{curt,wts}$), and involuntary load shedding (l_{dts}) for scenario s and hour t .

The first stage variables are determined prior to the realization of uncertainties. The objective function is subject to the base case, $N-1$ contingencies, and wind and load forecast error scenario constraints in (9)-(20). The $N-1$ contingencies would only apply to the base case. The cost of deploying reserves for the $N-1$ contingencies is not considered in the objective function since the algorithm considers such contingencies as constraints and guarantees the scheduling of necessary generating reserves to respond to the $N-1$ contingencies without shedding any loads. Wind and load forecast errors are considered in scenarios ($s=NC+1$ to NS) for scheduling the hourly reserves.

B. Base Case Constraints

Power balance equation for the base case is given in (9). Load shedding is not allowed for the base case, since the available generation capacity would utilize the load.

$$\sum_{i=1}^{NG} P_{it0} + \sum_{i=1}^{NW} P_{wt0} = \sum_{d=1}^{ND} P_{D,d,t0} \quad \forall t \quad (9)$$

Unit generation and reserve constraints and wind power curtailment

$$\begin{aligned} P_{it0} + RR_{u,it} + SR_{u,it} &\leq P_{max,i} \cdot I_{it} \\ P_{it0} - RR_{d,it} - SR_{d,it} &\geq P_{min,i} \cdot I_{it} \\ 0 &\leq RR_{u,it} \leq RR_{max,i} \\ 0 &\leq RR_{d,it} \leq RR_{max,i} \\ 0 &\leq SR_{u,it} \leq SR_{max,i} \\ 0 &\leq SR_{d,it} \leq SR_{max,i} \quad \forall i, \forall t \\ 0 &\leq DRR_{rt} \leq DRR_{max,r} \quad \forall r, \forall t \\ 0 &\leq P_{wt0} \leq P_{\psi,wt0} \quad \forall w, \forall t \\ P_{curt,wt0} &= P_{\psi,wt0} - P_{wt0} \quad \forall w, \forall t \end{aligned} \quad (10)$$

Ramp up and down limits

$$\begin{aligned} P_{it0} - P_{i(t-1)0} &\leq (1 - y_{it})UR_i + y_{it}P_{min,i} \\ P_{i(t-1)0} - P_{it0} &\leq (1 - z_{it})DR_i + z_{it}P_{min,i} \\ y_{it} - z_{it} &= I_{it} - I_{i(t-1)} \\ y_{it} + z_{it} &\leq 1 \quad \forall i, \forall t \end{aligned} \quad (11)$$

Minimum on/off time limits

$$\begin{aligned}
 UT_i &= \max\{0, \min[NT, (MU_i - TU_{i0})I_{i0}]\} \\
 \sum_{t=1}^{UT_i} (1 - I_{it}) &= 0 \quad \forall i \\
 \sum_{m=t}^{t+MU_i-1} I_{im} &\geq MU_i y_{it} \quad \forall i, \forall t = UT_i + 1, \dots, NT - MU_i + 1 \\
 \sum_{m=t}^{NT} (I_{im} - y_{it}) &\geq 0 \quad \forall i, \forall t = NT - MU_i + 2, \dots, NT \\
 DT_i &= \max\{0, \min[NT, (MD_i - TD_{i0})(1 - I_{i0})]\} \\
 \sum_{t=1}^{DT_i} I_{it} &= 0 \quad \forall i \\
 \sum_{m=t}^{t+MD_i-1} (1 - I_{im}) &\geq MD_i z_{it} \\
 \forall i, \forall t &= DT_i + 1, \dots, NT - MD_i + 1 \\
 \sum_{m=t}^{NT} (1 - I_{im} - z_{it}) &\geq 0 \quad \forall i, \forall t = NT - MD_i + 2, \dots, NT \quad (12)
 \end{aligned}$$

Fuel and emission limits of thermal units can be added as in [19]. The generalized network constraints refer to network constraints in the base case and scenarios [20].

$$C_{net}(P_{it0}, P_{wt0}) \leq 0, \quad \forall t \quad (13)$$

C. N-1 contingency and Wind-Load Scenario Constraints

Here (14) and (15) indicate that the system load in scenario s is supplied by generation, reserves, DRRs, and involuntary load shedding.

$$\begin{aligned}
 \sum_{i=1}^{NG} P_{its} + \sum_{r=1}^{NDR} DRR_{rts} + \sum_{d=1}^{ND} l_{dts} + \sum_{w=1}^{NW} P_{wts} &= \sum_{d=1}^{ND} P_{D,dts} \quad \forall t, \forall s \quad (14) \\
 P_{its} &= P_{it0} + RR_{its} + SR_{its} \quad \forall i, \forall t, \forall s \quad (15)
 \end{aligned}$$

$P_{its} = 0$ for every t if generator i is on outage at scenario s . The deployed reserves and involuntary load shedding in scenario s are determined based on the scheduled generation capacities. The wind energy delivery in scenario s at time t is limited by the available wind generation.

$$\begin{aligned}
 -RR_{d,it} &\leq RR_{its} \leq RR_{u,it} \quad \forall i, \forall t, \forall s \\
 -SR_{d,it} &\leq SR_{its} \leq SR_{u,it} \quad \forall i, \forall t, \forall s \\
 -DRR_{d,rt} &\leq DRR_{rts} \leq DRR_{u,rt} \quad \forall r, \forall t, \forall s \\
 0 &\leq P_{wts} \leq P_{\psi,wts} \quad \forall w, \forall t, \forall s \\
 P_{cwt,wts} &= P_{\psi,wts} - P_{wts} \quad \forall w, \forall t, \forall s \\
 0 &\leq l_{dts} \leq l_{dt,max} \quad \forall d, \forall t, \forall s \\
 l_{dts} &= 0 \quad \forall d, \forall t, s = \{1, \dots, NC\} \quad (16)
 \end{aligned}$$

The involuntary load shedding variables are set to zero for the first iteration of $N-1$ contingency calculations so that consumers can utilize all available generation resources. However, if a few scenarios remain to be infeasible, the involuntary load shedding will be made available in the following iterations as an option for mitigating the scenario violations. The ramp limit for non-wind energy units in scenario s is

$$\begin{aligned}
 P_{its} - P_{i(t-1)s} &\leq (1 - y_{it})UR_i + y_{it}P_{\min,i} \\
 P_{i(t-1)s} - P_{its} &\leq (1 - z_{it})DR_i + z_{it}P_{\min,i} \quad \forall i, \forall t, \forall s \quad (17)
 \end{aligned}$$

Once a contingency occurs, the system load is defined in (18) as the total load minus the allowable system load imbalance Δ . The amount of system load imbalance is defined by the type of the contingency for an acceptable range of frequency changes [21]. The regulation reserve is considered in (18)-(19) for supplying the load in contingencies.

$$\sum_{i=1}^{NG} P_{IMB,its} + \sum_{r=1}^{NDR} DRR_{rts} + \sum_{w=1}^{NW} P_{wts} \geq \sum_{d=1}^{ND} P_{D,dts} - \Delta_s \quad \forall s \in \{1, \dots, NC\}, \forall t \quad (18)$$

$$P_{IMB,its} = P_{it0} + RR_{its} \quad \forall i, \forall s \in \{1, \dots, NC\}, \forall t \quad (19)$$

The network constraints in scenario s are represented by

$$C_{net}(P_{its}, P_{wts}, RR_{its}, SR_{its}, DRR_{rts}, l_{dts}) \leq 0 \quad \forall t, \forall s \quad (20)$$

If there is a line outage in scenario s , (20) will incorporate the required changes in generator and load incidence matrices and the corresponding line flows [22].

IV. PROPOSED SOLUTION METHODOLOGY

The proposed MIP problem is represented by the objective function (8), subject to constraints (9)-(20). For large systems with many possible contingencies and wind and load forecast errors, the problem might be intractable due to the increased size of constraints and variables. Therefore, we resort to decomposition as shown in Fig. 2. The algorithm depicts the application of Benders decomposition to the solution of the proposed scheduling problem.

The master UC problem includes first and second-stage variables described in Section III-A plus the network cuts (21) for the base case and scenarios.

$$C_{net}(P_{it0}, P_{wt0}) \leq 0 \quad \forall t$$

$$C_{net}(P_{its}, P_{wts}, RR_{its}, SR_{its}, DRR_{rts}, l_{dts}) \leq 0 \quad \forall t, \forall s \quad (21)$$

The dc power network subproblems consider the master problem solution to detect flow violations and send cuts to the master UC problem as necessary [20].

Fig. 2. Flowchart of the proposed scheduling algorithm

V. CASE STUDIES

The proposed algorithm is applied to a six-bus system to capture the essential characteristics of the algorithm, and to the modified IEEE-118 bus system to assess the performance of the proposed solution. The method is also applied to the northwest region of the Turkish electric power market.

A. Six-Bus System

The six-bus system data are given in [3] in which a wind energy unit with a maximum power output of 20MW is added at bus 6. The one-line diagram of the system is given in Fig. 3. The system has three thermal units, four transmission lines, two tap-changing transformers, and one phase shifter for MW control. The generation units from cheapest to most expensive are G1, G2, and G3. The regulation reserve prices are 14, 13 and 11 \$/MW, spinning reserve prices are 11, 10 and 8 \$/MW for three units respectively. Flow limits of lines are 200, 150, 150, 100MW for lines 1-2, 1-4, 2-4, 5-6 respectively.

DRP bids include three discrete points with q_r^k of 1.8MW, 3.6MW and 5.4MW, and cc_{rt}^k of 10, 13 and 16 \$/MW respectively at each time interval. The deployment cost ec_{rt}^k is 10 \$/MW and the $VOLL$ is 450 \$/MWh at each load bus. The scenario reduction tool of the General Algebraic Modeling System (GAMS) is used in which the reduction method is set to the Mix of Fast Backward/Forward methods [23]. Initially there were 1500 Monte Carlo scenarios with even probabilities (1/1500) which are reduced to 10 scenarios with a relative distance of 75%. The relative distance would be 70% and 83% when the Monte Carlo scenarios are reduced to 50 and 9 scenarios, respectively [24].

Fig. 3. One-line diagram for six-bus system

TABLE I
PROBABILITY OF SCENARIOS AFTER SCENARIO REDUCTION

Scenario	1	2	3	4	5
Probability	0.26	0.12	0.08	0.07	0.14
Scenario	6	7	8	9	10
Probability	0.09	0.02	0.07	0.07	0.08

Fig. 4. Wind power forecast and scenarios

The wind curtailment cost is 50 \$/MW which is higher than the largest marginal cost of the given thermal units. The standard deviation of wind forecast error will gradually increase from 0 to 6.5% of the forecast from $t=0$ to 24. The standard deviation of the system load forecast error is 3% of the load forecast at each time interval. The probability of scenarios is given in Table I. The forecasted wind and its error scenarios are depicted in Fig. 4. The following three case studies are considered:

Case 1: Deterministic case (without network contingencies).

Case 2: Stochastic wind and load forecast errors in Case 1.

Case 3: $N-1$ contingencies in Case 2.

Case 1: This case provides a reference in which no contingency or uncertainty is considered. The total system operation cost is \$99,061. Table II depicts the scheduling of three thermal units and the wind energy units. The available wind energy is fully utilized since the wind energy units are assumed to be price-takers. G1 is scheduled at all hours since it is the cheapest unit. G2 is committed in the first hour due to min up constraints. G2 is scheduled to generate between hours 11-21, while G3 is scheduled between 13-19, since these are the next expensive units in the ascending order. No reserves or DR are scheduled in the base case.

TABLE II
CASE 1 GENERATION DISPATCH (MW)

Hour	G1	G2	G3	W1
1	161.88	10	0	11.82
2	162.05	0	0	11.4
3	156.33	0	0	10.51
4	153.13	0	0	9.7
5	153.67	0	0	9.49
6	159.51	0	0	9.18
7	173.91	0	0	7.95
8	191.92	0	0	7.3
9	206.97	0	0	7.7
10	218.79	0	0	7.75
11	230	0	0.4	7.79
12	230	0	8.16	7.66
13	230	10	4.42	7.61
14	230	10	6.19	7.28
15	230	11.71	10	7.12
16	230	18.47	10	7.43
17	230	19.27	10	6.85
18	230	10.64	10	6.04
19	230	10	9.25	6.64
20	230	0	9.08	8.02
21	230	0	8.61	8.44
22	227.57	0	0	9.11
23	199.39	0	0	10.68
24	194	0	0	11.68

Fig. 5. Wind generation curtailments in Case II Solid line: zero curtailment at base case. Dotted line: wind energy curtailments in scenarios.

Case 2: This case includes wind and load forecast errors which are considered through the Monte-Carlo scenarios. The total system cost increases to \$104,431. The base case dispatch is identical to that of Case 1. Fig. 5 depicts the wind power curtailments in the base case and scenarios. The algorithm curtails small amounts of wind in order to not utilize expensive regulation and spinning-down reserves. However, it should be noted that wind power curtailment might not be allowed in certain cases. The algorithm does not schedule regulation reserves in Case 2 other than 1.12 MW for hour 12 and 2 MW for hour 19 from G3. The spinning reserve dispatch and DR are given in Table III. These are the maximum deployable reserves available to the scenarios. Involuntary load shedding of 790, 50, 1450, 470, 120 and 7010 kWh is utilized in scenarios 1,2,3,4,5,7 respectively. The maximum load shedding occurs in the 7th scenario with the smallest probability. The expected system cost in Case II will increase to \$104,592 when the involuntary load shedding is not allowed. The day-ahead system cost without DRR is \$104,973 which will be reduced once DRR replaces the expensive units.

TABLE III
CASE 2 RESERVE DISPATCH (MW)

Hour	SR _u			SR _d			DR		
	G1	G2	G3	G1	G2	G3	DRP1	DRP2	DRP3
1	5.07	0	0	4.83	0	0	0	0	0
2	8.55	0	0	7.04	0	0	0	0	0
3	5.38	0	0	2.29	0	0	0	0	0
4	5.77	0	0	2.21	0	0	0	0	0
5	7.87	0	0	2.28	0	0	0	0	0
6	4.51	0	0	0.88	0	0	0	0	0
7	10.82	0	0	4.81	0	0	0	0	0
8	4.12	0	0	4.56	0	0	0	0	0
9	7.98	0	0	4.36	0	0	0	0	0
10	4.66	0	0	2.35	0	0	0	0	0
11	1.51	0	6.67	2.73	0	1.9	0	0	0
12	0	0	1.67	0	0	6.67	1.8	1.8	1.8
13	0	0	5.43	0	0	4.42	0	0	1.8
14	0	2.32	6.67	0	2.85	0.32	0	0	0
15	0	6.06	1.05	0	2.76	6.67	0	0	0
16	0	7.59	0.02	0	8.5	0	0	0	0
17	0	12.31	0	0	3.06	0	0	0	0
18	0	8.41	0	0	0.64	3.4	0	0	0
19	0	0	0.75	0	0	6.67	3.6	3.6	3.6
20	0	0	0.92	0	0	6.67	0	0	1.8
21	0	0	1.39	0	0	6.67	5.4	5.4	5.4
22	3.34	0	6.67	0	0	2.37	0	0	0
23	13.83	0	0	3.98	0	0	0	0	0
24	4.34	0	0	6.63	0	0	0	0	0

Case 3: Two *N-1* contingencies of G3 and the transmission line (between buses 3-6) are considered along with the 10 wind and load forecast scenarios. The system cost increases to \$105,848 in Case 3 with an expected involuntary load shedding of 138.2kWh. The involuntary load shedding in this case is due to infeasibilities in wind and load scenarios. The DR schedule is identical to that in Case 2. The reserve dispatch for Case 3 is given in Table IV. The expensive regulation reserve is deployed for managing contingencies. The wind generation in the base Case 3 is curtailed, similar to that in Case 2, to consider the *N-1* contingencies. When DRR is not allowed, the optimal expected system cost is \$106,041 with an expected involuntary load shedding of 20kWh.

Sensitivity Analysis: A sensitivity analysis is performed to evaluate the effect of wind and load forecast errors. Fig. 6

depicts the error levels versus the expected costs. In order to compare the effect of wind and load forecast errors, the standard deviation of wind is normalized by the maximum capacity of wind energy unit and the standard deviation of load is normalized by the maximum system load. First the system load forecast error is fixed to that of Case 3 (3%) and wind forecast error is varied starting from that of Case 3 (6.5%) to 32%. We observe that the wind forecast error does not affect the expected system cost significantly due to the limited availability of wind generation. Then the wind forecast error is fixed to that of Case 3 (6.5%) and the system load forecast error is varied starting from that of Case 3 (3%) to 12%. The expected system cost increases sharply due to the allocation and the deployment of additional reserves to respond to the increasing volatility of the system load.

TABLE IV
CASE 3 RESERVE DISPATCH (MW)

Hour	RR _u		SR _u			SR _d		
	G2	G3	G1	G2	G3	G1	G2	G3
1	0	0	5.07	0	0	4.83	0	0
2	0	0	8.55	0	0	7.04	0	0
3	0	0	5.38	0	0	2.29	0	0
4	0	0	5.77	0	0	2.21	0	0
5	0	0	7.87	0	0	2.28	0	0
6	0	0	4.51	0	0	0.88	0	0
7	0	0	10.82	0	0	4.81	0	0
8	0	0	4.12	0	0	4.56	0	0
9	0	0	7.98	0	0	4.36	0	0
10	0	0	4.66	0	0	2.35	0	0
11	0	0	8.17	0	0	4.63	0	0
12	0	0	1.84	4.83	0	7.78	0	0
13	3.33	0	0	0	6.67	3.95	1.08	0.01
14	3.32	0	0	0	6.67	3.8	2.87	0
15	8.05	0	0	0	1.95	6.85	3.66	0
16	10	0	0	0	0	6.79	8.47	0
17	10	0	0.35	1.96	0	7.32	0	0
18	9.78	0	0	0	0.22	4.02	0.86	0
19	3.33	0	0	0	6.67	3.54	5.92	0
20	0	0	0	0	3.56	6.23	0	0
21	0	3.02	1.39	0	6.67	6.7	0	0
22	0	0	2.43	0	0	2.37	0	0
23	0	0	13.83	0	0	3.98	0	0
24	0	0	4.34	0	0	6.63	0	0

Fig. 6. Expected system cost versus wind energy and load forecast errors

Fig. 7 depicts the expected cost of uncertainty at each wind penetration level when the standard deviation of system load forecast error is 3%. The wind penetration refers to the installed capacity, and the hourly mean production is proportional to the installed capacity. Here, for a lower wind

penetration, the sensitivity of the expected system cost to wind energy forecast error is insignificant. This is because the required reserve would be low as the uncertainty is increased at the limited penetration level of 20 MW. However, the expected cost would increase for a higher penetration level as the forecast error is increased.

Fig. 7. Expected system cost with the wind penetration level

B. Modified IEEE 118-Bus System

The Modified IEEE 118-Bus system is used to evaluate the efficiency of the proposed method. There are 186 branches and 91 loads. Three wind energy units are added to the 54 existing units. There are 50 DRPs at certain load buses which provide bids to the reserve market. The VOLL is 400 \$/MWh at each load bus. Seven $N-1$ contingencies include the outage of generators at buses 77, 82, 105, 113 and the outage of lines 17-113, 114-115 and 17-113. The wind and load forecast errors are represented by 1500 Monte Carlo scenarios. The number of scenarios is reduced to 12 by using forward-backwards scenario reduction techniques [23]. The data are available at motor.ece.iit.edu/data/Data_118_Bus.pdf. Table V shows the generation units with allocated reserves, $RR_{u,ib}$, $RR_{d,ib}$, $SR_{u,ib}$, $SR_{d,ib}$. Here, the $RR_{u,ib}$, $RR_{d,ib}$, $SR_{u,ib}$, $SR_{d,ib}$ values for the listed units are positive for at least one hour in 24 hours.

TABLE V
RESERVE ALLOCATION AMONG UNITS IN THE 118-BUS SYSTEM CASE

	Regulation Up	Spinning Up	Spinning Down
Considering Demand Response	-	7, 29, 34, 39, 43, 45, 47, 51	5, 7, 10, 19, 22, 26, 27, 29, 30, 34, 39, 40, 43, 45, 47, 51, 52
No Demand Response	4, 7, 19, 22, 23, 26, 28, 30, 40	7, 10, 11, 14, 19, 22, 26, 27, 29, 30, 34, 35, 36, 37, 39, 40, 43, 45, 47, 48, 51, 52, 53	7, 10, 19, 22, 26, 27, 29, 30, 34, 36, 39, 40, 43, 45, 47, 48, 51, 52

The total expected system cost is \$1,270,517 without DR. The allocated reserves include 155 MWh of regulation-up, 3076 MWh of spinning-up, and 2204 MWh of spinning-down reserve. No involuntary load shedding is deployed. When DR is considered, the expected cost reduces to \$1,263,126, and expensive regulation reserve capacity is not allocated. The spinning-up reserve is reduced to 251MWh while the spinning-down reserve remains nearly the same at 2376 MWh. 2987 MWh of DR is allocated using DRPs for contingency and wind and load forecast error scenarios whenever they are cheaper than spinning-up reserve bids. Similar to the case without DR, no involuntary load shedding is allocated. The solution curtailed 182.27MWh of wind energy for

accommodating $N-1$ contingencies and forecast errors in both cases. The solution time in the latter case is 1 hour, 42 minutes, with an Intel Xeon 2.4GHz CPU and 64 GB of RAM.

Scalability Analysis: This analysis evaluates the performance when the number of $N-1$ contingencies and the error forecast uncertainty are increased. Here, two tests are performed. First, three $N-1$ contingencies are considered with 12, 18, and 24 forecast error scenarios. The change in the solution time is observed. Second, $N-1$ contingencies are changed to 3, 7, and 11 while the number of forecast error scenarios is kept at 12. The results are presented in Table VI and Fig. 8. Here, the slope of the solution time is decreased as the number of contingencies and the level of uncertainties are increased. This is because some scenarios would require higher reserve allocations, and once the situation with these scenarios are resolved, the additional scenarios might not require much further reserve allocations. Besides, the performance is more sensitive to the number of $N-1$ contingencies since one contingency could introduce more constraints to the problem.

C. Northwest Region of Turkish Power System

Turkey has taken major steps towards building the country's electricity market since the enactment of Turkish Electricity Market Law in 2001 [25]. In this section, the proposed model is applied to the northwest region of the Turkish Power System which includes large industrial activities. The proposed scheduling model would study the coordination of hourly reserve and DR requirements when wind and load forecast uncertainties are considered. The subsystem depicted in Fig. 9 is composed of 173 buses, 28 thermal generating units, 66 branches, and 131 transformers.

TABLE VI
SCALABILITY ANALYSIS

$N-1$ Contingencies	Uncertainty Scenarios	Variables	Equality Constraints	Inequality Constraints
3	12	422,640	111,552	146,088
	18	583,488	157,776	199,944
	24	744,336	204,000	253,800
3	12	422,640	111,552	146,088
7		519,504	131,856	181,800
11		616,368	152,160	217,512

Fig. 8. Solution time versus $N-1$ contingency or uncertainty scenarios

Two $N-1$ contingencies are considered as the outages of one of the generators at bus NUHENERJI_A and the transmission line COLAKOGLU-KROMANCELİK. 1500 scenarios are created to simulate wind and load forecast errors which are reduced to 12 scenarios. The standard deviations for wind and load forecaster error are 6.5%, and 4% respectively. Considerable industrial loads appear at buses DILISKELESI, COLAKOGLU, ICMELER, DUDULLU and GEBZEOSB.

These loads are mostly composed of shipyards, steel mills, and cement manufacturing facilities in an industrial zone.

Three 100 MW wind farms are located at three buses SILE, KARAMURSEL and YALOVA, which have considerable wind potential. Detailed data are included in motor.ece.iit.edu/data/Data_TR.pdf. Six DRP buses are DILISKELESI, COLAKOGLU, DUDULLU, KOSEKOY, KUCUKBAKKAL, and GEBZEOSB, with both residential and industrial loads. For instance, cement factories could curtail consumption and shift production when required by the ISO. The DRP bids are 7, 14, and 21 MW at 7, 9, and 11 \$/MW and the deployment prices at 17.5, 22.5, 27.5 \$/MW respectively.

The expected day-ahead system cost without DRR is \$559,039 while the cost reduces to \$549,289 when DRR is considered. The wind curtailment is 78.38MWh in both cases (see Table VII). DRR replaces 870 MWh of spinning-up, 915 MWh of spinning-down, and 44 MWh of regulation-up reserves, and reduces the costs by \$9,750. The DRPs are paid a total of \$17,045, for participating in the DRR program.

Fig. 9. Northwest region of Turkish Electric Power Network

TABLE VII
ALLOCATED DRRS (MW) OF DRPs

Hour	1	2	3	4	5	6	7	8	9	10	11	12
DRP	1	7	0	0	0	7	7	7	7	7	7	7
	2	7	0	7	0	0	0	14	7	7	7	7
	3	0	7	7	0	0	0	7	14	14	0	14
	4	7	7	0	0	7	0	0	7	7	7	7
	5	0	7	7	0	0	0	14	7	7	7	7
	6	7	0	7	0	0	7	7	14	7	7	7
Hour	13	14	15	16	17	18	19	20	21	22	23	24
DRP	1	7	0	7	7	7	7	14	21	0	7	0
	2	7	7	7	7	7	7	14	14	7	7	0
	3	14	14	14	14	14	14	14	14	7	14	14
	4	7	7	7	7	7	7	0	0	0	7	0
	5	7	7	7	7	7	7	7	7	7	7	7
	6	7	7	7	7	7	7	14	14	7	7	0

VI. CONCLUSIONS

The proposed method is used to analyze the effect of $N-1$ contingencies, wind and load uncertainties and DRP bids in the hourly generation scheduling. The proposed algorithm curtails the wind generation in scenarios in order to not allocate expensive regulation and spinning-down reserves. The sensitivity analyses show that the expected system cost is

more sensitive to load forecast errors. The effect of wind forecast error depends on the wind penetration level. The system cost decreases as the wind penetration increases since the operating cost of wind energy units is neglected. However, the expected cost increases considerably with the increasing wind forecast errors. A scalability analysis is performed which shows that the rate of change in the solution time decreases sharply as the number of considered contingencies is increased or wind and load volatilities are higher. Furthermore, it is observed that the solution performance is more sensitive to the number of contingencies since contingencies could add more variables and constraints to the problem. It is also shown that the integration of DR at proper locations and periods would reduce the cost of the security-based power system scheduling.

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Hourly Coordination of Electric Vehicle Operation and Volatile Wind Power Generation in SCUC

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Abstract— In this paper, the coordinated integration of aggregated plug-in electric vehicle (PEV) fleets and renewable energy sources (wind energy) in power systems is studied by stochastic security-constrained unit commitment (Stochastic SCUC) model, which minimizes the expected grid operation cost while considering the random behavior of the many PEVs. PEVs are mobile and distributed devices with deferrable options for the supply/utilization of energy at various times and locations. The increased utilization of PEVs, which consume electricity rather than fossil fuel for driving, offers unique economic and environmental opportunities, and brings out new challenges to electric power system operation and planning. The storage capability of PEVs could help power systems mitigate the variability of renewable energy sources and reduce grid operation costs. Vehicle-to-grid (V2G) enables PEVs to have bi-directional power flows once they are connected to the grid, i.e., they can either inject power to, and draw power from, the grid which adds further complexity to power system operations. PEVs signify customers' random behavior when considering their driving patterns, locational energy requirements, topological grid interconnections, and other constraints imposed by the consumers. Numerical tests demonstrate the effectiveness of the proposed approach for analyzing the impact of PEVs on the grid operation cost and hourly wind energy dispatch.

Index Terms—Plug-in electric vehicles, renewable energy sources, V2G, load aggregation, stochastic security-constrained unit commitment.

NOMENCLATURE

Variables

b, j, o	Index of bus
$C_{(.)}^{(.)}$	Operation cost of PEV fleet
$E_{v,t}^{(.)}$	Available energy in batteries of fleet v at time t
$E_{v,t}^{net}$	Net discharged energy of PEV fleet v at time t
$F_{c,(.)}, F_{c,(.)}^r$	Production/availability cost function of a thermal unit
i	Denotes a thermal unit
$I_{(.)}^{(.)}$	Unit status indicator, 1 means on and 0 means off
$I_{c,(.)}^{(.)}$	Indicator of PEV fleet in charging mode
$I_{dc,(.)}^{(.)}$	Indicator of PEV fleet in discharging mode

$I_{i,(.)}^{(.)}$	Indicator of PEV fleet in idle mode
k	Denotes a hydro unit
l	Index of transmission line
m	Denotes a segment of curves
$P_{(.)}^{(.)}$	Generation of a unit
$P_{d,w,t}^{(.)}$	Power generation curtailed of wind unit w at hour t
$P_{c,(.)}^{(.)}, P_{dc,(.)}^{(.)}$	Charge/discharge power of PEV fleet
$P_{m,(.)}^{(.)}$	Charge/discharge power rate at segment m
$PL_{l,t}^{(.)}$	Real power flow on line l at hour t
s	Denotes a scenario
$SD_{(.)}^{(.)}$	Shutdown cost of a unit
$SU_{(.)}^{(.)}$	Startup cost of a unit
t	Hour index
v	Denotes a PEV fleet
w	Denotes a wind unit
$\theta_{(.)}^{(.)}$	Bus angle
$\Delta_{(.)}^{max}$	Maximum permissible power adjustment of a unit

Constants:

$B_{b,t}^{(.)}$	Set of units which are connected to bus b at time t
$b_{m,(.)}$	Slope of segment m in linearized charge/discharge curve
CD_k, CS_k	Shutdown/startup cost of hydro unit k
D_b	Set of loads which are connected to bus b
$DR_{v,t}^s$	Energy for PEV v to drive at time t in scenario s
E_v^{min}, E_v^{max}	Min/max energy stored in batteries of PEV fleet v
$E0_v, ET_v$	Initial and terminal stored energy in PEV fleet v
$L_{f,b}, L_{t,b}$	Set of lines starting from/ending at bus b
$N_{v,t}$	Status of grid connection of fleet v at time t
NE_v^s	Ratio of the number of PEVs in fleet v in scenario s to the number of base case PEVs
NT	Number of hours under study
p^b	Probability of the base case solution
p^s	Probability of scenario s

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$P_{(\cdot)}^{\min}, P_{(\cdot)}^{\max}$	Min/max generation capacity
$P_{c,v}^{\min}, P_{c,v}^{\max}$	Min/max charging capacity of PEV fleet v
$P_{dc,v}^{\min}, P_{dc,v}^{\max}$	Min/max discharging capacity of PEV fleet v
$P_{D,(\cdot)}^{(\cdot)}$	Total system demand
$P_{f,w,t}^{(\cdot)}$	Forecasted wind power of wind unit w at hour t
$P_{m,v}^{\max}$	Maximum power output at segment m in charging/ discharging cost curve of PEV fleet v
$PL_l^{\max}$	Maximum capacity of line l
$\hat{T}$	Time in which the charging state is set to a value
$UX_{(\cdot)}^{(\cdot)}, UY_{(\cdot)}^{(\cdot)}$	Outage status, 1 if available, and otherwise 0
X_{jo}	Inductance of a line between buses j and o
η_v	Cycle charging efficiency of PEV fleet

I. INTRODUCTION

Plug-in electric vehicles (PEVs) represent hourly distributed and mobile demands in power systems which could also provide distributed storage to power grids [1],[2]. The aggregated storage capability of PEVs can help shift the hourly generation portfolio and reduce grid operation costs. Hence, a dramatic increase in the number of PEVs could have a major impact on power system operations. Once aggregated at the distribution level, the distribution company (DISCO) will submit the information on marginal cost, storage capacity, and location of PEV fleets to the ISO for participation in the day-ahead market.

Wind energy is the fastest growing renewable energy resource [3]. The large penetration of wind energy could decrease the operation cost and the emission of hazardous gases from fossil plants. However, the variability of wind energy could impose adverse effects on the dynamic and static security of power systems. [4]-[5] studied the integration of storage for mitigating the effect of hourly wind energy variability on power systems. Likewise, V2G could offer ancillary services and reduce operation costs in power systems.

References [6]-[8] focused on storage technologies and power electronic grid-connection interfaces for facilitating large-scale adoptions of PEVs. Economic potentials of PEVs for participating in regulation services were investigated in [9]. The role of PEV in the integration of renewable energy resources was addressed in [10]. The integration of PEV in power systems was investigated in [11] and major issues for the V2G implementation were discussed. The electricity market issues of PEV integration were presented in [12].

Unlike conventional storage capabilities, the grid-connection storage topography of PEVs may change during the daily operation of power systems. PEVs consume energy according to their driving requirements. In addition, the total PEV energy drawn from the grid could be much larger than the energy injected to the grid [13]-[16]. While most of the previous studies addressed the economic aspects of integrating PEVs to power systems, they lack the transmission system security consideration offered by the PEV interconnection and its daily profile in power systems.

The contributions of this paper include the modeling of large scale PEV integration as mobile distributed load and storage facilities and their impacts on the optimal operation of security-constrained power systems. The study considers physical limitations of power systems, hourly load and wind energy uncertainties, and random outages of generation and transmission components in PEV integration.

The rest of the paper is as follows. Section II discusses the proposed Stochastic SCUC formulation. Section III illustrates the effectiveness of the proposed methodology by a 6-bus system and the IEEE 118-bus system. Detailed discussions and conclusions are presented in Sections IV and V, respectively.

II. PROPOSED STOCHASTIC SCUC FORMULATION

PEV fleet characteristics include starting locations and destinations of PEV fleets, departure and arrival times at designated locations, and PEV charging locations and patterns which could be bundled into power system operations. A random number of PEVs is assumed for each fleet. The state of charge (SOC), energy consumption, and min/max capacity of a PEV fleet is a function of the number of PEVs and their operating characteristics. SOC is the ratio of available energy to maximum storable energy in the battery. The available energy in the PEV battery is computed by multiplying the given SOC by the maximum storable energy in the battery. The energy consumption in a fleet, which is a parameter, depends on the number of PEVs and their energy requirements. The driving habits in a fleet would determine the charging/discharging patterns of aggregated PEVs.

The proposed formulation is a stochastic optimization problem in which the wind energy and load forecast errors, power system component outages, number of PEVs in a fleet and their energy requirements are considered as variables. The proposed solution determines the hourly unit commitment and dispatch of generating units and charge/discharge states of PEV fleets.

The Monte Carlo simulation method is utilized in the proposed stochastic model. Random outages in power systems are represented by incorporating probability distribution functions and forced outage rates. Load forecast errors, PEV energy consumption patterns, and the number of PEVs in a fleet are represented by truncated normal distribution functions in which the mean values are the forecasts and the standard deviations are percentages of the mean values [17]-[18]. Wind speed variations are simulated by the Weibull distribution function, auto correlation factor and diurnal pattern [19], and wind generation is procured by incorporating the wind turbine power curve and wind speed at wind sites. Forward and backward algorithms are developed to reduce the number of scenarios with an acceptable accuracy [20]-[21]. The convex operation cost of aggregated PEVs would depend on the number of vehicles and charging/discharging cycles [9].

The proposed Stochastic SCUC is a mixed-integer programming (MIP) optimization problem. The objective (1) is to minimize the grid operation cost subject to system and unit constraints (2)-(28). The objective function includes the base case operation cost, in which the forecasted quantities of load, wind, and hydro are incorporated, and outages of generators and

transmission lines are not considered. We also consider in the objective function the availability cost for providing spinning reserve in Monte Carlo scenarios. The availability cost refers to the payment to generators that provide reserves. The provision of reserve is exercised as a corrective action by generators in response to the realization of uncertainties. It is assumed that the generators can provide corrective actions, which are restricted by their ramp up/down limitations. The availability cost is considered as one third of the marginal cost of a generating unit [22]. The objective function further includes the expected cost of corrective actions in scenarios for accommodating uncertainties. In this formulation, load curtailment is not acceptable in scenarios, and the system should serve the load in the base case and all scenarios. Alternatively, load curtailment could have been considered by adding the respective penalty factor to the objective function. Thermal units are formulated as non-quick start units, so their scenario commitment status is the same as that in the base case. Thus, there is no need to introduce extra startup/shutdown costs in scenarios.

The system and generating unit constraints in the base case are shown in (2)-(14). Detailed thermal unit constraints are available in [23]. Hydro unit constraints are provided in [24]. Wind curtailment constraint is shown in (2) in which the sum of dispatched and curtailed wind power is the same as the wind power forecast. The wind curtailment occurs when there is an insufficient ramping down capability of thermal units or a significant transmission congestion for utilizing the available wind power in power systems. The base case PEV fleet constraints are shown in (3)-(10). The net hourly absorbed/delivered energy is given in (3), which shows that the difference in the energy gained from the grid/stored in the aggregated PEV battery and the energy delivered back to the grid from the PEV is quantified by the charging cycle efficiency of the aggregated PEV. The hourly charge/discharge/idle modes of fleets which are mutually exclusive are given in (4). Charge/discharge power constraints are given in (5)-(6). The hourly energy balance in PEV batteries is given in (7). The given parameter $N_{v,t}$ indicates connectivity of PEV fleet to the system. Once a PEV fleet is connected to the power system (i.e., $N_{v,t} = 1$), the aggregated battery is either charged by drawing power from the grid (5), or discharged by injecting power to the grid (6). If the PEV fleet is not plugged-in (i.e., $N_{v,t} = 0$), the charging/discharging power will be zero according to (4)-(6). The energy capacity limit of each fleet is presented in (8)-(9). The piecewise linear representation of convex charge/discharge cost curve of PEV batteries is shown in (10), which represents the depth of discharge and cycles to failure of the battery for calculating the cost of energy drawn or delivered by PEV batteries. As the depth of aggregated battery discharge increases, the number of cycles to failure would decrease. This indicates a higher cost for charging/discharging of the battery because the total energy stored by/drawn from the battery during its lifetime will decrease for a fixed battery price [9], [11]. Hence, the operation cost of aggregated PEV has a direct correlation with the depth of charging/discharging batteries [12]. The nonlinear battery charging/discharging cost curves are piecewise linearized for consideration in the proposed MIP

formulation. A tighter piecewise linear approximation was presented in the authors' previous work [25]. In the consumer-controlled scheme, the aggregated SOC of PEVs is set to be fixed at specific operation periods (11). It is assumed that the SOC is at 100% when a PEV fleet is leaving the station. (12)-(14) represent the base case dc power flow constraints.

The PEV fleet scenario constraints are shown in (15)-(23) and the consumer-controlled scenario scheme is represented by (24). The wind scenario constraint includes a set similar to (2), except base case variables are replaced by scenario variables. The scenario corrective action is enforced by (25) where the hourly cost of corrective action, $F_{c,i}^r(\Delta_{i,t}^{\max})$, is included in (1).

(26)-(28) represent dc power flow constraints for each Monte Carlo scenario. The grid connection of PEV fleet at time t is represented by $B_{b,t}^v$ in (26).

$$\text{Min} \left[\sum_t \sum_i (p^b \cdot F_{c,i}(P_{i,t}) + SU_{i,t} + SD_{i,t}) + \sum_t \sum_k (SU_{k,t} + SD_{k,t}) + \sum_t \sum_v C_{v,t} \right] + \left[\sum_t \sum_i (F_{c,i}^r(\Delta_{i,t}^{\max})) \right] \quad (1)$$

$$+ \sum_s p^s \cdot \left[\sum_t \sum_i F_{c,i}(P_{i,t}^s) + \sum_t \sum_k (SU_{k,t}^s + SD_{k,t}^s) + \sum_t \sum_v C_{v,t}^s \right]$$

s.t.

$$P_{w,t} + P_{d,w,t} = P_{f,w,t} \quad (2)$$

$$E_{v,t}^{net} = P_{dc,v,t} - \eta_v \cdot P_{c,v,t} \quad (3)$$

$$P_{v,t} = P_{dc,v,t} - P_{c,v,t} \quad (4)$$

$$I_{dc,v,t} + I_{c,v,t} + I_{i,v,t} = N_{v,t} \quad (5)$$

$$I_{c,v,t} \cdot P_{c,v}^{\min} \leq P_{c,v,t} \leq I_{c,v,t} \cdot P_{c,v}^{\max} \quad (6)$$

$$I_{dc,v,t} \cdot P_{dc,v}^{\min} \leq P_{dc,v,t} \leq I_{dc,v,t} \cdot P_{dc,v}^{\max} \quad (7)$$

$$E_{v,t} = E_{v,t-1} - E_{v,t}^{net} - (1 - N_{v,t}) \cdot DR_{v,t} \quad (8)$$

$$E_v^{\min} \leq E_{v,t} \leq E_v^{\max} \quad (9)$$

$$E_{v,0} = E_{v,NT} \quad (10)$$

$$C_{v,t} = N_{v,t} \cdot \left(\sum_m b_{m,v} \cdot P_{m,v,t} \right) \quad (11)$$

$$0 \leq P_{m,v,t} \leq P_{m,v}^{\max} \quad (12)$$

$$N_{v,t} \cdot |E_{v,t} - E_{v,t-1}| = \sum_m P_{m,v,t}$$

$$E_{v,\hat{T}} = E_v^{\max} \quad (13)$$

$$\sum_{i \in B_b^i} P_{i,t} + \sum_{w \in B_b^w} P_{w,t} + \sum_{v \in B_b^v} P_{v,t} \quad (14)$$

$$+ \sum_{k \in B_b^k} P_{k,t} = \sum_{d \in D_b} P_{D,t}^d + \sum_{l \in L_{f,b}} PL_{l,t} - \sum_{l \in L_{t,b}} PL_{l,t}$$

$$PL_{l,t} = (\theta_{j,t} - \theta_{o,t}) / X_{jo} \quad (15)$$

$$|PL_{l,t}| \leq PL_l^{\max} \quad (16)$$

$$C_{v,t}^s = N_{v,t} \cdot \left(\sum_m b_{m,v} \cdot P_{m,v,t}^s \right) \quad (17)$$

$$0 \leq P_{m,v,t}^s \leq P_{m,v}^{\max} \cdot NE_v^s \quad (18)$$

$$N_{v,t} \cdot |E_{v,t}^s - E_{v,t-1}^s| = \sum_m P_{m,v,t}^s$$

$$\begin{aligned}
E_{v,t}^{net,s} &= P_{dc,v,t}^s - \eta_v \cdot P_{c,v,t}^s \\
I_{dc,v,t}^s + I_{c,v,t}^s + I_{i,v,t}^s &= N_{v,t} \\
N_{v,t} \cdot I_{c,v,t}^s P_{c,v}^{\min} \cdot NE_v^s &\leq P_{c,v,t}^s \leq N_{v,t} \cdot I_{c,v,t}^s P_{c,v}^{\max} \cdot NE_v^s \\
N_{v,t} \cdot I_{dc,v,t}^s P_{dc,v}^{\min} \cdot NE_v^s &\leq P_{dc,v,t}^s \leq N_{v,t} \cdot I_{dc,v,t}^s P_{dc,v}^{\max} \cdot NE_v^s \\
E_{v,t}^s &= E_{v,t-1}^s - E_{v,t}^{net,s} - (1 - N_{v,t}) \cdot DR_{v,t}^s \cdot NE_v^s \\
E_v^{\min} \cdot NE_v^s &\leq E_{v,t}^s \leq E_v^{\max} \cdot NE_v^s \\
E_{v,0}^s &= E_{v,NT}^s = E_{v0} \cdot NE_v^s \\
P_{v,t}^s &= P_{dc,v,t}^s - P_{c,v,t}^s \\
P_{v,\hat{T}}^s &= E_v^{\max} \cdot NE_v^s \\
-\Delta_{i,t}^{\max} &\leq P_{i,t}^s - UX_{i,t}^s \cdot P_{i,t} \leq \Delta_{i,t}^{\max} \\
P_{i,t}^{\min} \cdot UX_{i,t}^s \cdot I_{i,t} &\leq P_{i,t}^s \leq P_{i,t}^{\max} \cdot UX_{i,t}^s \cdot I_{i,t} \\
\sum_{i \in B_b^i} P_{i,t}^s + \sum_{w \in B_b^w} P_{w,t}^s + \sum_{v \in B_b^v} P_{v,t}^s \\
&+ \sum_{k \in B_b^k} P_{k,t}^s = \sum_{d \in D_b} P_{D,t}^s + \sum_{l \in L_{f,b}} PL_{l,t}^s - \sum_{l \in L_{l,b}} PL_{l,t}^s \\
-M \cdot (1 - UY_{i,t}^s) &\leq PL_{i,t}^s - (\theta_{j,t} - \theta_{i,t}) / X_{jo} \leq M \cdot (1 - UY_{i,t}^s) \\
-PL_{i,t}^{\max} UY_{i,t}^s &\leq PL_{i,t}^s \leq PL_{i,t}^{\max} UY_{i,t}^s
\end{aligned}
\tag{16-28}$$

Considering the grid complexity along with the stochastic nature and the mobility of V2G, the proposed optimization problem in (1)-(28) represents a large-scale, non-convex, non-deterministic polynomial-time hard (NP-hard) problem [26].

Fig. 1. Proposed Stochastic SCUC with PEV integration in power systems

The solution to the original problem in such cases would be an intractable task without decomposition. The problem is decomposed into a master MIP problem and several linear programming (LP) subproblems. After the master problem is solved, the subproblems check the network constraints in the

base case and all scenarios. Network evaluations for the base case and all scenarios are independent which can be optimized in parallel. Benders cuts are generated and fed back to the master problem to mitigate any violation encountered in the base case or any scenario. The decomposition and respective formulation is shown in Fig. 1.

III. CASE STUDIES

In this section, a 6-bus power system and the 118-bus power system are studied to demonstrate the effectiveness of the proposed approach for analyzing the impact of aggregated PEVs on operation cost, wind curtailment, and optimal unit commitment and dispatch of generation facilities including thermal, hydro, and wind units along with PEV fleets.

A. 6-Bus Power System

A 6-bus power system shown in Fig. 2 is considered to study the integration of PEVs into the power grid. Generators and transmission line data are shown in Tables I and II, respectively. PEVs in various locations are categorized into different fleets based on their driving characteristics. The available energy, max/min capacity and charge/discharge power of individual vehicles are aggregated in PEV fleet characteristics representing max/min capacities, SOC, and max/min charging/discharging capabilities. Tables III and IV show five fleets in the power system. The charging efficiency of a fleet is 85% which is the ratio of energy stored in the battery to the energy drawn from the grid.

TABLE I
THERMAL UNIT CHARACTERISTICS

Unit	a (\$/MW ²)	b (\$/MW)	c (\$/h)	$P_{\min}$ (MW)	$P_{\max}$ (MW)	SU (\$)	SD (\$)	Min. Up (h)	Min. Dn. (h)
G1	0.099	6.589	211.4	100	320	100	50	4	3
G2	0.203	7.629	217.4	10	160	200	40	3	2
G3	0.494	10.07	102.8	10	100	80	10	1	1

TABLE II
TRANSMISSION LINE CHARACTERISTICS

Line ID	From Bus	To Bus	Impedance (p.u)	Capacity (MW)
1	1	2	0.170	65
2	1	4	0.258	70
3	2	4	0.197	40
4	5	6	0.140	40
5	3	6	0.018	75
6	2	3	0.037	80
7	4	5	0.037	65

Fig. 2. 6-bus power system

TABLE III
PEV FLEET CHARACTERISTICS

PEV fleet No.	Min Cap. (MWh)	Max Cap. (MWh)	Min Charge/ Discharge (kW)	Max Charge/ Discharge (MW)	a (\$/MW ²)	b (\$/MW)	c (\$/h)
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1	13.152	65.76	7.3/6.2	24.8/21.08	0.17	8.21	0
2	10.96	54.8	7.3/6.2	14.58/12.4	0.20	8.21	0
3	5.48	27.4	7.3/6.2	7.29/6.2	0.41	8.21	0
4	8.768	43.84	7.3/6.2	11.67/9.92	0.25	8.21	0
5	10.96	54.8	7.3/6.2	14.58/12.4	0.20	8.21	0

TABLE IV
PEV FLEET TRAVEL CHARACTERISTICS

PEV fleet No.	Number of PEVs	First Trip				Second Trip			
		Departure Time	Bus	Arrival Time	Bus	Departure Time	Bus	Arrival Time	Bus
1	3,400	6:00	5	8:00	1	17:00	1	19:00	5
2	2,000	7:00	4	8:00	2	16:00	2	17:00	4
3	1,000	5:00	4	7:00	2	16:00	2	18:00	4
4	1,600	5:00	6	6:00	3	17:00	3	18:00	6
5	2,000	7:00	5	9:00	3	18:00	3	20:00	5

The PEV fleets have different energy requirements. The annual driving distance by a PEV fleet is 12,000 miles with a 32.88 miles average per day [10], [27]. The energy required by a PEV is 9 kWh/day with an average 3.65 miles/kWh [9]. So, the hourly energy required by the fleets is 7.65, 9.00, 2.25, 7.20 and 4.50 MWh, respectively. We assume the required energy for driving in one direction is the same as that of returning to the starting point. The installed wind capacity is 75 MW, which is about 30% of the system peak load with an hourly average wind generation of 11.7%.

We consider two modes of operation. In the grid-controlled mode, PEV charge/discharge decisions are made by power system operators based on the system operation and driving requirements. In the consumer-controlled scheme, SOC at certain hours are adjusted to represent consumer charging/discharging requirements. The following four cases are considered to evaluate the impact of PEVs on the optimal operation of power systems:

Case 1: Deterministic Solution – Grid-Controlled mode

Case 2: Deterministic Solution – Consumer-Controlled mode

Case 3: Stochastic Solution – Grid-Controlled mode

Case 4: Stochastic Solution – Consumer-Controlled mode

1) *Case 1: Deterministic Solution – Grid-Controlled mode*

The system load, wind generation and driving requirements are the same as forecasts. The operation cost is \$115,541.36 and the wind curtailment is 0 MWh. Table V shows the charge/discharge mode of PEV fleets in which the aggregated V2G enables a cheaper energy delivery at peak hours. In Table V, the first fleet at bus 5 will inject power to the grid at hour 5 when the bus LMP is higher. The fleet will charge PEV at bus 1 rather than bus 5. Likewise, the fifth fleet will not charge/discharge when connected to bus 5 as both the lowest and the highest LMPs occur on bus 3. In Fig. 3 the maximum LMP is 121.6 \$/MWh at bus 3. The LMPs at buses 3 and 5 are higher at hours 3, 5 and 16-18. The fourth and fifth fleets in Table V are discharged at hours 16, and 16-17, respectively to take advantage of higher LMPs on bus 3. Table VI shows the hourly commitment of generators in which the third generator is not committed for the first six hours in the morning.

The grid operation cost and wind curtailment will increase to \$117,424.15 and 1.2 MWh, respectively, if the aggregated PEVs are stationary (i.e., always connected to the same bus.) These quantities will decrease when PEVs are mobile in the grid. The mobility of PEVs could enhance the optimal

generation while satisfying the fleet requirements. However, constraints imposed by consumers on the energy required for driving a vehicle, maximum storage capacity, and SOC could limit the optimal grid operation. For example, the fourth fleet departs bus 6 in the morning with an SOC of 36.4% and returns in the evening with an SOC of 74.8%. This indicates that the energy is transferred from bus 3 to bus 6 via the fourth fleet.

PEVs may reduce the operation cost by storing energy in one bus without transferring the energy elsewhere. The SOC of the fifth fleet when departing and returning to bus 5 is 36.4%, and the power exchange occurs when the PEV is connected to bus 3. Fig. 4 shows the generation dispatch in which the standard deviation of generation dispatch for Generators 1-3 is 16.1, 10.8 and 11.2 MW, respectively.

TABLE V
POWER DISPATCH OF PEVS IN GRID CONTROLLED SCHEME (MW)

Fleet	Hours (1-12)											
	1	2	3	4	5	6	7	8	9	10	11	12
1	0	0	0	0	0.72	0	0	0	-0.01	0	0	-5.9
2	-7.0	0	0	0	0	-0.47	0	-12.9	-7.98	0	0	0
3	0	0	0	0	0	0	0	-7.29	-3.29	0	0	0
4	0	-0.99	1.96	-0.96	0	-11.6	-11.6	-10.3	0	0	0	5.49
5	0	0	0	0	0	0	0	0	-11.2	0	0	0

Fleet	Hours (13-24)											
	1	2	3	4	5	6	7	8	9	10	11	12
1	0	-15.4	0	-15.4	0	0	0	0	0	0	0	0
2	-12.9	0	0	0	12.4	7.50	0	0	0	0	-3.25	0
3	-6.45	0	0	0	0	5.48	0	0	0	0	0	0
4	-11.6	0	-2.39	3.86	0	9.92	-0.08	2.14	3.57	-1.71	2.40	0
5	-14.6	-11.8	-10.9	10.9	12.4	0	0	0	0	0	0	0

Fig. 3. LMPs in Case 1

TABLE VI
COMMITMENT STATUS IN GRID CONTROLLED SCHEME OF CASE 1

Unit	Hours (1-24)																					
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22
G1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
G2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
G3	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1

Fig. 4. Hourly dispatch of generators in Case 1

2) *Case 2: Deterministic Solution – Consumer-Controlled mode*

The grid operation cost increases to \$119,084.33 as the consumer-controlled mode imposes further constraints on charge/discharge of PEVs. Table VII shows the dispatch of PEV fleets. The wind curtailment is 0 MWh. Comparing Tables VII and V, it is clear that the required SOC at the departure time will cause the fleet to draw more energy from the grid. Unlike

Case 1, the fifth fleet at bus 5 is charged at hours 1 and 6 to set the desired SOC at the departure time. Table VIII shows the hourly commitment of thermal generators in which G3 is committed at additional hours as compared to Case 1. Table IX shows a higher LMP and congestion at peak hours in the consumer-controlled scheme.

Fig. 5 shows the generation dispatch profile in which the standard deviations of generation dispatch for Generators 1-3 are 14, 10.4 and 20 MW, respectively. So the generation profile of the most expensive generator (Gen. 3) in Case 1 is smoother than that in Case 2. Hence, a flexible PEV control can reduce the volatility when integrating renewable resources into the grid. The generation dispatch volatility could increase the grid operation cost due to turbine wear and tear.

TABLE VII
HOURLY POWER DISPATCH OF PEVS IN CASE 2 (MW)

Fleet	Hours (1-12)											
1	-8.23	0	0	0	-9.76	0	0	-1.72	-0.01	0	0	0
2	-9.59	0	0	0	0	-12.3	0	0	0	0	0	0
3	-5.29	0	0	0	0	0	-5.29	0	0	0	0	0
4	0	-10.3	-4.33	-10.3	0	-8.47	0	0	0	1.93	0	5.49
5	-10.6	0	0	0	0	-0.01	0	0	0	1.96	0	0
Fleet	Hours (13-24)											
1	0	0	-0.81	-15.4	0	0	0	0	0	0	0	0
2	-10.6	0	0	0	12.4	0	0	0	0	0	-3.25	0
3	0	0	0	0	0	0	0	0	0	0	0	0
4	-8.73	0	0	0	0	6.68	-2.93	2.14	5.282	0	2.403	0
5	-12.9	0	0	0	0	0	0	0	0	0	0	0

TABLE VIII
HOURLY COMMITMENT IN CONSUMER CONTROLLED SCHEME OF CASE 2

Unit	Hours (1-24)																					
G1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
G2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
G3	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1

TABLE IX
MAXIMUM LMPs (\$/MWh)

Bus	Case 1	Case 2
1	30.0	30.0
2	32.0	32.0
3	121.6	336.0
4	64.1	137.9
5	75.0	175.5
6	116.3	317.7

Fig. 5. Hourly dispatch in consumer-controlled scheme in Case 2

3) Case 3: Stochastic Solution – Grid-Controlled mode

In this case, load and wind forecast errors, generation and transmission outages, and the number of PEVs in a fleet and their energy requirements are considered random. The load forecast error follows a normal distribution with a mean value equal to the forecasted load and standard deviation of 5%. The forecast error of energy consumption for driving and the number of PEVs in a fleet follow a normal distribution with

mean values equal to the forecast as shown in Tables III and IV, and the standard deviation of 5% and 20% of the mean values, respectively. The wind generation forecast is procured based on the typical wind power curve and generated wind speed data. The mean daily wind speed is 10 m/s, which follows a Weibull distribution function with Weibull coefficient equal to 2.1.

The deterministic solution applied to the proposed stochastic model would result in the operation cost and the expected demand mismatch penalty of \$129,184.989 and \$25,146, respectively. While in the stochastic solution, the operation cost and demand mismatch penalty are \$128,174.713 and \$20,913, respectively. Hence, the stochastic solution would lower the operating cost by \$5,243.276 (i.e., 129,184.989+25,146-128,174.713-20,913), which is the value of stochastic programming.

In Table X, a case with higher transmission line capacities is considered to avoid any demand mismatch due to transmission congestions. In this case, the grid operation cost in the base case is \$113,454.555 and the availability cost of the system is \$1,789.359, while the wind curtailment in the base case and the expected wind curtailment in scenarios are 117.32 MWh and 40.762 MWh, respectively. Table XI shows the hourly commitment of thermal units in which the third unit is not committed for 7 hours.

TABLE X
TRANSMISSION LINE CHARACTERISTICS

Line ID	From Bus	To Bus	Capacity(MW)	FOR
1	1	2	97	1%
2	1	4	100	1%
3	2	4	113	1%
4	5	6	81	1%
5	3	6	121	1%
6	2	3	111	1%
7	4	5	103	1%

TABLE XI
HOURLY COMMITMENT IN CASE 3

Unit	Hours (1-24)																					
G1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
G2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
G3	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1

4) Case 4: Stochastic Solution – Consumer-Controlled mode

Like Case 2, the consumers set the SOC of PEVs prior to departure. In this case, the base case operation cost and availability cost are \$114,498.69 and \$2,108 while the wind curtailment in the base case and the expected wind curtailment in scenarios are 121.097 MWh and 40.816 MWh, respectively. Here, the base case operation cost, availability cost and wind curtailment are increased as compared to those in Case 3. Table XII shows the hourly commitment of generators that are different from those in Case 3. The hourly commitment of G3 is increased by two hours in this case.

TABLE XII
HOURLY COMMITMENT IN CASE 4

Unit	Hours (1-24)																					
G1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
G2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
G3	0	0	0	0	0	1	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1

B. 118-Bus Power System

In this case, the modified IEEE 118-bus system shown in <http://motor.ece.iit.edu/EV/118.emf> is considered. Five 150

MW wind generation sites are considered on buses 12, 31, 66, 72 and 100, respectively. Table XIII shows the intermittent wind speed information. A total of 100,000 PEVs are divided into 5 fleets based on their driving patterns. The PEVs in fleets are 34,000, 20,000, 10,000, 16,000 and 20,000, respectively. Table XIV shows the fleet characteristics. The fleet travel schedules are similar to those in the previous case study. The same four cases discussed in the 6-bus system are considered.

Table XV shows the optimal base case cost and wind curtailment in each case. Table XVI shows the expected wind curtailment and the availability cost in Cases 3 and 4. In the grid-controlled scheme, the expected wind curtailment and availability cost are lower. Table XVII shows the operation cost. Comparing Cases 3 and 4, the operation costs are higher in the consumer-controlled scheme because of introducing additional constraints. The results are consistent with that in the previous case study. The CPU in this case is about 58 h on a 3.6 GHz personal computer with CPLEX 12.1. Parallel processing of a larger server with multiple CPUs or several large servers could reduce the computation time. In addition, practical considerations for the implementation of PEV in a specific power system could introduce additional short cuts for reducing the computation time. The grid operation cost will decrease with larger size PEV storage. However, the primary goal of PEV fleets is transportation rather than the provision of ancillary services in power grids.

TABLE XIII
WIND SPEED PROFILE AT SITES

	site 1	site 2	site 3	site 4	site 5
Weibull Coefficient	1.17	2.03	2.19	2.9	2.26
Auto Correlation Factor	0.761	0.943	0.957	0.88	0.928
Diurnal Wind Pattern	0.11	0.0944	0.0969	0.0196	0.0668
Hour of Peak Wind Speed	24	14	13	20	22

TABLE XIV
PEV FLEET CHARACTERISTICS

PEV Fleet	Min Energy (MWh)	Max Energy (MWh)	Charge/Discharge		a (\$/MW ²)	B (\$/MW)	c (\$/h)
			Min (kW)	Max (MW)			
1	131.52	986.4	7.3/6.2	248/210.8	0.57	27.35	0
2	109.6	822	7.3/6.2	145.8/124	0.68	27.35	0
3	54.8	411	7.3/6.2	72.9/62	1.36	27.35	0
4	87.68	657.6	7.3/6.2	116.7/99.2	0.85	27.35	0
5	109.6	822	7.3/6.2	145.8/124	0.68	27.35	0

TABLE XV
RESULTS FOR FOUR CASES (BASE CASE)

Case	Cost (\$)	Wind Curtailment (MWh)
1	1,323,982	305.456
2	1,327,672	348.572
3	1,352,637	178.216
4	1,357,843	169.145

TABLE XVI
EXPECTED SCENARIO RESULTS FOR CASES 3 AND 4

Case	Avail. Cost (\$)	Exp. Wind Curtail (MWh)
3	12,649,754	328.57
4	14,289,818	367.28

TABLE XVII
SCENARIO COSTS IN CASES 3 AND 4 (\$)

Scenario	Case 3	Case 4
1	1,371,254	1,378,357
2	1,457,163	1,466,943
3	1,408,596	1,414,523
4	1,369,053	1,374,058
5	1,413,558	1,414,729
6	1,423,133	1,427,015
7	1,428,505	1,429,073

8	1,374,482	1,378,838
9	1,411,435	1,415,783
10	1,444,603	1,444,894
11	1,397,722	1,401,078
12	1,408,407	1,419,582

Fig. 6 shows the relationship between the PEV storage capacity, the charging/discharging cost, and the grid operation cost. The battery capacity factor shows the size of the battery as a percentage of a nominal battery capacity. The operation cost factor (OCF) shows the charging/discharging cost as a percentage of nominal cost for battery operation. In Fig 6, grid operation cost decreases as OCF is reduced. Also, the grid operation cost decreases as PEV battery capacity factor increases. Unlike the grid-controlled scheme, the increase in PEV storage capacity may not reduce the grid operation cost in the consumer-controlled scheme. The SOC constraints may restrict the V2G reduction of the grid operation cost. Fig. 6 shows that the increase in PEV charging/ discharging costs will restrict the PEV storage participation to the operation cost reduction. The PEV contribution to the operation cost reduction may not be significant in an unconstrained (no transmission congestion) power system and system operators may consider dispatching more expensive units rather than using PEV fleets as storage.

Fig. 6. Grid operation cost in a grid-controlled scheme

IV. DISCUSSIONS

The integration of PEVs will introduce distributed and mobile demands and storage in power systems. The mobility of PEV fleets will impose additional operation constraints and introduce benefits for supplying critical power system loads in specific locations and periods. The variability of renewable generation resources may also be managed properly by charging/discharging capability of mobile PEV fleets.

Once PEVs are connected to the grid, they can draw energy, store it in batteries, and inject it back to the grid at other times and locations in order to decrease grid operation costs. Once in the V2G mode, PEVs can transfer energy between locations and contribute to the provision of ancillary services and congestion mitigation in transmission systems. Hence, V2G can help ISOs lower grid operation costs by taking advantage of the fact that the stored energy in PEVs can be transmitted between locations without obeying power flow rules.

However, PEV utilization in power systems could introduce additional obstacles and limitations. One issue is that the cost of storing and delivering energy by PEV for reducing power system operation costs may not be much cheaper than that of energy supplied by the grid. The higher charging/discharging cycles may reduce the battery life and impose further

limitations on PEV operations as a vehicle. Moreover, PEV storage requirements as a vehicle could impose further restrictions on the grid utilization of PEV storage. Another challenge is the availability of PEV at certain hours and locations as storage when PEV is mobile. The driving patterns and the number of vehicles in each fleet can alter the characteristics of ancillary services provided by PEV fleets. However, the transmission congestion cost over an extended period could far exceed the PEV storage cost.

V. CONCLUSIONS

In this paper, the impact of integrating PEV fleets into power systems is evaluated. The proposed stochastic model incorporates the modeling of PEV fleets according to the power system and PEV fleet constraints and requirements. The contributions of the paper include:

- The PEV fleet modeling in power systems is considered using the MIP formulation.
- The detailed power transmission system modeling and transmission constraints are included in the model.
- The integration of high penetration of renewable generation resources in power systems is considered.
- The uncertainties imposed by PEV fleets, renewable energy resources, and transmission and generation components are included.
- The operation schemes of PEV fleets and their impacts on power system operations are considered.
- The impact of PEV on thermal generation profile in power systems is evaluated.

It is shown that the PEV mobility can efficiently transfer energy throughout the network. PEVs can also help reduce the grid operation cost by providing energy storage for renewable energy resources. The PEV charging/discharging costs, limited storage capacity, required energy for driving PEV, and the SOC constraints imposed by consumers will further restrict the reduction in grid operation costs. When consumers set the SOC of PEVs, the grid operation costs will increase and PEV capabilities for transferring energy between locations will be limited.

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Hybrid AC/DC Transmission Expansion Planning

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Abstract—This paper proposes a hybrid algorithm for the AC/DC transmission expansion planning (TEP). The stochastic simulation method would consider random outages of generating units and AC/DC transmission lines as well as load forecast errors. The mixed-integer linear programming problem is decomposed into a master planning problem with integer investment decision variables and subproblems which examine the feasibility of master planning solution and calculate the optimal operation schedule over the planning horizon. The independent system operator (ISO) would utilize the proposed method to select the optimal set of AC/DC transmission lines for satisfying TEP criteria: supplying load forecasts, minimizing investment costs, and optimizing market operations. The proposed set of DC transmission system may use either current source converters (CSCs) or voltages source converters (VSCs). Numerical examples illustrate the effectiveness of the proposed TEP model.

Index Terms—DC transmission lines, transmission expansion planning, reliability, optimal system operation

NOMENCLATURE

Indices:

b	Index for bus
e	Index for subperiod
h	Index for DC converter
i	Index for unit
j	Index for AC lines
k	Index for DC transmission system
l	Index for a DC line
m, n	Starting and ending buses of AC lines
s	Index of scenario
t	Index for year

Parameters:

Bid_{tei}	Bid price of unit i at subperiod e in year t
CJ	Number of AC candidate lines
CK	Number of DC candidate transmission systems
d	Discount rate
D_{ste}	Load block at subperiod e in year t for scenario s
DT_{te}	Number of hours at subperiod e in year t

EJ	Number of existing AC lines
EK	Number of existing DC transmission systems
IC_j^C	Investment cost of the candidate AC line j
$IC_{dc,k}^C$	Investment cost of the candidate DC transmission system k
$LOEP$	Loss of energy probability
LSC_{teb}	Load shedding price of load b at subperiod e in year t
M	A large positive constant value (e.g. $10e+8$)
NB	Number of buses
NE	Number of subperiods
NI	Number of units
NS	Number of scenarios
NT	Number of planning years
x_j	Reactance of AC line j
$P_{dc,h}^{Min}, P_{dc,h}^{Max}$	Minimum and maximum active power transfer of converter h
P_i^{Min}, P_i^{Max}	Minimum and maximum generation output of generating unit i
PL_j^{Max}	Maximum power flow limit of AC line j
Pr_s	Probability of scenario s
A	AC bus-unit incidence matrix
B	AC bus-load incidence matrix
C	AC bus-converter incidence matrix
K	AC bus-AC line incidence matrix

Variables:

LS_{teb}	Load shedding of bus b at subperiod e in year t for scenario s
$P_{dc,h}$	Active power withdrawal of converter h
P_{stei}	Generation dispatch of the unit i at subperiod e in year t for scenario s
PL_j	Active power flow of AC line j
$PL_{dc,l}$	Active power flow of DC line l
WF, WO	Objective function for reliability check and optimal operation subproblems
Y_{jt}	Installation status of the candidate AC line j in year t (1 if installed, otherwise 0)

Azim Lotfjou is with Genscape Inc. in Boston, MA. Mohammad Shahidehpour is with the Robert W. Galvin Center at Illinois Institute of Technology. Yong Fu is with the Department of Electrical and Computer Engineering, Mississippi State University, MS 39759 USA. This study was funded in part by the U.S. Department of Energy Grants # DE-EE 0002979 and DE-EE 0001380.000.

$Y_{dc,kt}$	Installation status for the candidate DC system k in year t (1 if installed, otherwise 0)
Z_{lower}	Lower bound for TEP objective function
Z_{upper}	Upper bound for TEP objective function
θ	AC voltage angle
η, π	Dual variables of equality constraints
$\mathbf{D}$	Vector of bus loads
$\mathbf{LS}$	Vector of curtailed loads
$\mathbf{P}$	Active power output vector of generating units
$\mathbf{P}_{dc}$	Active power flow vector of DC converters
$\mathbf{PL}$	Active power flow vector of AC lines

Others:

$\wedge$	Given variables
C	Candidate AC/DC line
E	Existing AC/DC line

I. INTRODUCTION

HIGH voltage direct current (HVDC) transmission technology has salient characteristics in comparison with AC transmission, such as the bulk power delivery through underground or under marine cables, low power losses for long distance transmissions, asynchronous connection of AC systems, and stabilization of AC systems in contingencies [1]-[2]. DC transmission is utilized for its power flow controllability which can enhance economic operations, mitigate grid congestion, and prevent cascading outages. DC transmission system is the favorable option for delivering renewable energy from remote sites (e.g., off-shore wind) to load center. Such features have accelerated the deployment of DC transmission in restructured electric power systems.

In contrast to generation expansion planning (GEP) that is mainly driven by market forces, TEP is still regulated and managed by independent system operators (ISOs) in electricity markets. Transmission companies (TRANSCOs) recover their investment from transmission tariffs set by ISOs.

Although there are numerous publications on the optimal expansion planning of AC transmission systems in electricity markets [3]-[16], few studies have investigated the expansion planning of AC/DC transmission systems. References [17] and [18] emphasized that DC transmission systems represent an inevitable TEP alternative in competitive electricity markets. Reference [19] presented two-terminal and multi-terminal DC transmission system (MTDC) planning. MTDC configurations have higher installation costs for providing sophisticated control schemes. These complex control systems will guarantee a reliable operation of DC transmission systems over possible ranges of AC system operations. In order to effectively integrate DC transmission with AC power systems, a comprehensive TEP model would need to be developed for quantifying the benefits of such expansion projects.

In this paper, we focus on the reliability and the economic assessment of TEP. In order to justify the motivation for AC/DC TEP, a simple case study is considered to examine the economic benefits of controllable DC transmission, which is an important factor in the AC/DC TEP projects. Fig. 1 illustrates a three-bus system with three generating units and

two existing AC transmission lines. An additional 300-km AC/DC transmission line extended between buses 2 and 3 will be needed to supply the load of 1,350 MW at bus 3. As such the length of DC line is less than the “break-even distance of 600-800 km” [1] and it would be logical to choose an AC line with the investment cost of \$190 M instead of a DC line with the investment cost of \$320 M. However, Table I shows that if we select the AC line extending from bus 2 to bus 3, cheap generating unit 1 will only be dispatched at 960.69 MW which is less than its capacity of 1200 MW, due to the 600 MW limit on line 1-3. The expensive unit 3 is turned on alternatively to supply the 118.64 MW of load. However, if we select the controllable DC line between buses 2-3, the cheap generating unit 1 will be dispatched at its capacity which will allow more power transfer through the DC line. It is no longer necessary to turn on the expensive generating unit 3 and the total operating cost will be reduced from the \$24,915 (AC option) to \$20,844 (DC option).

Fig. 1. Three-bus system

TABLE I OPERATION WITH AC LINE 2-3 AND DC LINE 2-3 OPTIONS

Items	Capacity	With AC Line 2-3	With DC Line 2-3
G1	300 – 1200 MW	960.69 MW	1184.41 MW
G2	100 – 600 MW	600 MW	500 MW
G3	100 – 300 MW	118.64 MW	0 MW
Line 1-2	500 MW	160.69 MW	384.23 MW
Line 1-3	600 MW	600 MW	600 MW
Line 2-3	900 MW	660.26 MW	781.56 MW
System Operating Cost (\$)		\$24,915	\$20,844

For simplicity, we assume that the total load of 1650 MW is averaged hourly throughout the entire year. So, the total annual saving due to the DC transmission selection is about \$35.66 M ((24,915 - 20,844) × 8760), which means that the DC operation will pay off the difference (i.e., \$320M - \$190 M = \$130M) in 4 years (4 × \$35.66M = \$142.64M > \$130M). Therefore, it would be logical based on economics to select the DC transmission over an AC alternative.

This paper discusses a stochastic TEP approach to AC/DC transmission investment while considering transmission reliability constraints. The proposed model would investigate

the most economical AC/DC TEP by considering the investment cost of transmission facilities, system operation and load shedding costs, and physical system constraints. It is assumed that the information on GEP and the hourly load forecast is available. Random component outages and load forecast errors are taken into account in the stochastic simulation for the AC/DC TEP. The proposed TEP uses the decomposition optimization approach in which binding constraints are incorporated in the ISO's reliability check and optimal market operation subproblems.

The rest of this paper is organized as follows. Section II models the DC transmission system for a dc power flow analysis. Proposed ISO's TEP and formulations are thoroughly discussed in section III. Numerical examples are given in section IV. We summarize our conclusions in section V.

II. MODELING OF DC TRANSMISSION SYSTEM

In general, a DC transmission system consists of two or more converters (rectifiers and inverters), and one or more DC lines that link the converters [20-21]. Different converter technologies such as CSCs and VSCs are utilized in DC transmission systems. Possible DC transmission system converter configurations include monopolar, bi-pole and tri-pole. However, based on the number of converter stations, the HVDC systems can be classified into back-to-back, two-terminal and multi-terminal connections. In this study, we focus on the monopolar two-terminal and multi-terminal DC configuration for TEP. The proposed mathematical model may be easily expanded to any other DC configurations or operating modes.

The DC transmission system shown in Fig. 2 has two converters linked through a DC transmission. To simplify the model of DC link, we assume the total DC terminal withdrawals is zero which means power losses in DC terminals and lines are neglected. Consequently, considering converters 1 and 2 and DC line l in Fig. 2,

$$P_{dc,1} + P_{dc,2} = 0 \quad (1)$$

For each converter 1 or 2,

$$\begin{cases} P_{dc,h}^{Min} \leq P_{dc,h} \leq P_{dc,h}^{Max} & \text{Rectifier} \\ -P_{dc,h}^{Max} \leq P_{dc,h} \leq -P_{dc,h}^{Min} & \text{Inverter} \end{cases} \quad (2)$$

Fig. 2. A monopolar two-terminal DC transmission system

Here, $P_{dc,h} > 0$ indicates a rectifier operation. For the two-terminal DC system, the DC line loading is equal to the inverter power. Applying this model to CSC-DC systems, the dc current is unidirectional and the flow direction is changed by reversing the polarity of DC voltage. However, in VSC-DC systems, the dc voltage is unidirectional and the flow direction is changed by reversing the dc current. For CSC-DC systems,

the operation at zero power requires a special design which produces high valve losses and harmonic currents. However, in VSC-DC systems, the operation at zero power produces low losses which makes VSC a more favorable option for DC connections up to 200 MW. For a MTDC system with DC lines l and converters h shown in Fig. 3,

$$\sum_h P_{dc,h} = 0 \quad (3)$$

The set of (2)-(3) would model the DC transmission systems in dc power flow analyses and later will be used in the network reliability check subproblem.

Fig. 3. A multi-terminal DC transmission system

III. AC/DC TRANSMISSION PLANNING METHODOLOGY

Fig. 4 shows the proposed ISO's optimal AC/DC TEP algorithm. At first, TRANSCOs submit AC/DC transmission expansion proposals to the ISO. The ISO executes the proposed TEP algorithm to find the least cost investment plans over the TEP time horizon. Every planning year is divided into multiple subperiods. In Fig. 4, Benders reliability cuts will be generated in the case of reliability violations in any subperiods, which are passed along to the master planning problem to change the previous TEP decisions. Once all existing violations are removed, the optimal market operation will be executed to find an upper bound for the TEP problem.

In the optimal operation subproblem, the ISO executes the security-constrained economic dispatch (SCED) with DC lines modeled as constant injections at sending and receiving terminals. If the ISO's TEP stopping criteria cannot be satisfied based on the optimal operation results, Benders optimality cuts will be introduced to change the master planning decisions. This iterative process will continue until a feasible and optimal TEP schedule is obtained. If the ISO's TEP problem cannot converge after several iterations, there would be no feasible TEP schedules based on the given AC/DC transmission candidates. At this time, the ISO may request the participants to revise the candidate list, stop the TEP process, or make other decisions based on market expansion policies. The ISO may also apply load shedding to find a feasible solution based on the loss of energy probability (LOEP) requirement.

In this paper, the scenario analysis for the strategic TEP is implemented using the stochastic simulation method. This simulation is used to examine the AC/DC TEP performance based on random component outages and load forecast errors. The formulations of individual problems/subproblems are discussed as follows.

Fig. 4. Flowchart of the proposed hybrid AC/DC TEP model

A. Objective of the ISO in TEP Problem

The ISO's objective in the proposed TEP problem is to minimize the total investment, operation and load shedding costs for the AC/DC transmission systems. The objective function is given in (4) in which all costs are considered as net present values. The first term in (4) expresses the total investment cost for AC/DC TEP proposals. The second term in (4) is the total expected operation cost which is the sum of generation dispatch multiplied by bidding prices for all units. The third term in (4) is the total expected load curtailment cost over the planning time horizon. The approximate maintenance

cost over the project life span may be added to (4). The investment and maintenance costs of DC transmission systems depend on the level of reliability requirements [22].

Min

$$Z^{upper} = \sum_t \left(\frac{\sum_j^{CJ} IC_j^C * Y_{jt} + \sum_k^{CK} IC_{dc,k}^C * Y_{dc,kt}}{(1+d)^{(t-1)}} \right) \quad (4)$$

$$+ \sum_s^{NS} \sum_t^{NT} \sum_e^{NE} \sum_i^{NI} \left(\Pr_s \frac{DT_{te} * P_{stei} * Bid_{tei}}{(1+d)^{(t-1)}} \right) \\ + \sum_s^{NS} \sum_t^{NT} \sum_e^{NE} \sum_b^{NB} \left(\Pr_s \frac{DT_{te} * LS_{teb} * LSC_{teb}}{(1+d)^{(t-1)}} \right)$$

B. Formulation of Transmission Planning Master Problem

The Benders master planning problem in Fig. 4 is formulated as,

$$\text{Min } Z_{lower} \quad (5)$$

$$\text{s.t. } Z_{lower} \geq \sum_t^{NT} \left(\frac{\sum_j^{CJ} IC_j^C * Y_{jt} + \sum_k^{CK} IC_{dc,k}^C * Y_{dc,kt}}{(1+d)^{(t-1)}} \right) \quad (6)$$

$$Y_{jt} \leq Y_{j(t+1)} \quad \forall j, \forall t \quad (7)$$

$$Y_{dc,kt} \leq Y_{dc,k(t+1)} \quad \forall k, \forall t \quad (8)$$

The investment cost of AC transmission lines depends on the voltage level, length of the line, line flow capacity, and financial issues such as discount rates. The investment cost of DC transmission systems depends on DC system configuration, number of terminals, rating of each terminal, and converter type (CSC or VSC). Once the ISO obtains the initial transmission planning schedule, the network reliability check subproblem will be used to mitigate AC/DC transmission reliability violations. The network reliability check is formulated next. Once a feasible master planning problem is obtained, the network reliability is examined in the next section.

C. Formulation of Reliability Check Subproblem

In this subproblem, the ISO minimizes the load curtailment at load buses by adjusting generation outputs and DC converter flows. The ISO's reliability check subproblem for the s^{th} scenario at subperiod e in year t is formulated in (9)-(21). The ISO checks the network reliability for all scenarios in different years and subperiods. The equations (10) and (11) represent the transmission planning schedules given by the planning master problem. The set of (12)-(21) represents real power balance at AC buses, each DC system equality constraints, real power flows through existing and candidate AC lines, flow limit of existing and candidate AC lines, flow limit of existing and candidate DC converters, generation limit of each generating unit, and the reference bus angle, respectively.

$$\text{Min } WF_{ste} = \mathbf{1}^T \cdot \mathbf{LS} \quad (9)$$

s.t.

$$Y_{stej} = \hat{Y}_{jt} \quad \eta_{stej} \quad \forall j \quad (10)$$

$$Y_{dc,stek} = \hat{Y}_{dc,kt} \quad \eta_{stek} \quad \forall k \quad (11)$$

$$\mathbf{K} \cdot \mathbf{PL}_s + \mathbf{C} \cdot \mathbf{P}_{dc,s} + \mathbf{S}_{1,s} - \mathbf{S}_{2,s} = \mathbf{A} \cdot \mathbf{P}_s - \mathbf{B} \cdot \mathbf{D}_s \quad (12)$$

$$\sum_h P_{dc,h} = 0 \quad (13)$$

$$PL_{stej}^E = \frac{(\theta_{stem} - \theta_{sten})}{x_j^E} \quad \forall j \quad (14)$$

$$\begin{cases} PL_{stej}^C - \frac{(\theta_{stem} - \theta_{sten})}{x_j^C} \leq M * (1 - Y_{stej}) \\ PL_{stej}^C - \frac{(\theta_{stem} - \theta_{sten})}{x_j^C} \geq -M * (1 - Y_{stej}) \end{cases} \quad \forall j \quad (15)$$

$$-PL_j^{E,Max} \leq PL_{stej}^E \leq PL_j^{E,Max} \quad \forall j \quad (16)$$

$$-PL_j^{C,Max} \cdot Y_{stej} \leq PL_{stej}^C \leq PL_j^{C,Max} \cdot Y_{stej} \quad \forall j \quad (17)$$

$$\begin{cases} P_{dc,h}^{E,Min} \leq P_{dc,stek}^E \leq P_{dc,h}^{E,Max} & \text{Rect.} \\ -P_{dc,h}^{E,Max} \leq P_{dc,stek}^E \leq -P_{dc,h}^{E,Min} & \text{Inv.} \end{cases} \quad \forall h \quad (18)$$

$$\begin{cases} P_{dc,h}^{C,Min} * Y_{dc,stek} \leq P_{dc,stek}^C \leq P_{dc,h}^{C,Max} * Y_{dc,stek} & \text{Rect.} \\ -P_{dc,h}^{C,Max} * Y_{dc,stek} \leq P_{dc,stek}^C \leq -P_{dc,h}^{C,Min} * Y_{dc,stek} & \text{Inv.} \end{cases} \quad \forall h \quad (19)$$

$$P_i^{Min} \leq P_{stei} \leq P_i^{Max} \quad \forall i \quad (20)$$

$$\theta_{ref,ste} = 0 \quad (21)$$

If the loss of energy probability (LOEP) in (22) is not satisfied in all scenarios and at each subperiod, the Benders reliability cut (23) will be generated and added to the Benders master planning problem presented in (5)-(8).

$$\sum_s (Pr_s * WF_{ste}) / \sum_s (Pr_s * DT_{te} * D_{ste}) \leq LOEP \quad (22)$$

$$\begin{aligned} & \sum_s (Pr_s * WF_{ste}) + \sum_s \left(Pr_s \sum_j \eta_{stej} * (Y_{jt} - \hat{Y}_{jt}) \right) \\ & + \sum_s \left(Pr_s \sum_k \eta_{stek} * (Y_{dc,kt} - \hat{Y}_{dc,kt}) \right) \\ & \leq LOEP * \sum_s (Pr_s * DT_{te} * D_{ste}) \end{aligned} \quad (23)$$

Once the network reliability is managed, the ISO examines the optimality of selected schemes as presented in the next section.

D. Formulation of Optimal Operation Subproblem

The objective of the optimal operation subproblem is to minimize the operation and load curtailment costs based on submitted bids and contracts. The ISO's optimal operation for each scenario and each subperiod is formulated as follows.

$$\begin{aligned} \text{Min } WO_{ste} = & \sum_i \frac{DT_{te} * P_{stei} * Bid_{tei}}{(1+d)^{(t-1)}} \\ & + \sum_b \frac{DT_{te} * LS_{steb} * LSC_{teb}}{(1+d)^{(t-1)}} \end{aligned} \quad (24)$$

s.t.

$$Y_{stej} = \hat{Y}_{jt} \quad \pi_{stej} \quad \forall j \quad (25)$$

$$Y_{dc,stek} = \hat{Y}_{dc,kt} \quad \pi_{stek} \quad \forall k \quad (26)$$

And, constraints (12)-(21) are taken into account. Similarly, (25) and (26) represent the transmission planning schedule obtained from the Benders master planning problem. Once the ISO obtains an optimal solution for all scenarios at all subperiods, the ISO calculates the objective function (4) to get Z^{upper} . Then, the stopping criterion (27) will be checked.

$$\frac{(Z^{upper} - Z^{lower})}{Z^{lower}} \leq \varepsilon \quad (27)$$

If the stopping criterion (27) is not satisfied, a Benders optimality cut (28) will be added to the Benders master planning problem presented in (5)-(8).

$$\begin{aligned} Z^{lower} \geq & \sum_t \left(\frac{\sum_j \left(\sum_{CJ} IC_j \times Y_{jt} + \sum_{CK} IC_{dc,k} \times Y_{dc,kt} \right)}{(1+d)^{(t-1)}} \right) \\ & + \sum_s (Pr_s * WO_{ste}) + \sum_s \left(Pr_s \sum_t \sum_e \sum_j \pi_{stej} (Y_{jt} - \hat{Y}_{jt}) \right) \\ & + \sum_s \left(Pr_s \sum_t \sum_e \sum_k \pi_{stek} (Y_{kt} - \hat{Y}_{kt}) \right) \end{aligned} \quad (28)$$

This iterative process will continue until a feasible and optimal AC/DC TEP schedule is obtained.

IV. CASE STUDIES

A six-bus system and the modified IEEE 118-bus system are studied to show the effectiveness of the proposed hybrid AC/DC TEP. The choice of VSC or CSC lines is based on the system performance and economic evaluation. We assume that two-terminal and MTDC transmission systems have similar converter ratings at sending and receiving terminals. The discount rate is 10%. The total permissible load shedding is 1000 MW over the entire planning period. AC/DC line installations are considered at the beginning of each planning year. The stopping criterion ε is 0.05%. All cases are solved using CPLEX 12.0 on a dual core 2.66 GHz CPUs personal computer.

A. Six-bus System

A six-bus system is shown in Fig. 5. The pertinent data for the transmission network and generating units are listed in Tables II and III, respectively. The bidding strategy of units is assumed to be fixed. Table IV shows the load forecast for the entire planning period of 10 years. Load distribution factors are 0.2, 0.4 and 0.4 for loads at buses 3-5, respectively. There

B. IEEE 118-bus System

A modified IEEE 118-bus system presented in Fig. 6 has 54 units, 186 branches, and 91 demand sides. This larger system is selected to evaluate the proposed TEP algorithm. The 118-bus system data is given in <http://motor.ece.iit.edu/DC/Planning/IEEE118.xls> where 25 AC, 25 DC and 15 MTDC candidates are suggested for a 15-year TEP. Fig. 7 shows the schematic diagram of two-terminal DC transmission candidates (on the left) and MTDC transmission candidates (on the right). Random scenarios are created by the Monte Carlo simulation. The scenario reduction technique [25] is applied to reduce the number of scenarios which are listed in Table IX. We assumed that load distribution factors at all buses are fixed and all loads have the same annual growth rate of 2%. The total demand through first to fourth quarters of the first planning year are 4219 MW, 6000 MW, 4922 MW and 5461 MW, respectively. We use bus LMP differences to select TEP candidates. The additional AC/DC lines would mitigate the line congestion or transfer power from a low-LMP bus, with access to cheap generation, to a high-LMP bus supplied by expansive generating units. The cost of adding a 100MW AC line is \$1.2 M/mile. The cost of adding a 100MW DC system includes \$20M for two converter terminals (\$10M per each) and \$1M/mile for the line.

Fig. 6 The modified IEEE 118-bus system

Fig. 7 Two-terminal DC (left) and MTDC (right) candidates

The following two cases are studied

Case 1: TEP without considering any uncertainties

Case 2: TEP with pre-defined scenarios

Case 1: This is the base case power system. The existing system cannot supply the load in years 11-15 without the expansion of existing transmission system. For instance, at year 15, the load curtailment at bus 59 is 9.35MW which is due to the congested AC line 59-63. The load curtailment is not allowed at the base case, so the AC line 49-59 is installed

in year 10 to minimize the total investment and operation costs during years 10-15 and mitigate the transmission system bottlenecks in year 11. Though candidate lines AC 5-10, DC 5-10, MTDC 5-10-26 and MTDC 5-10-30 can be installed to solve the load shedding at bus 5, the operation and investment costs are minimized when the AC candidate line 6-113 is installed to supply the load at bus 5. Similarly, the DC candidate line 60-80 is installed on this year to transfer the cheap power from unit 36 at bus 80 to a load center at bus 60, remove the congestion, and avoid the load curtailment at bus 59. Table X shows that 5 AC, 4 DC and 2 MTDC transmission systems are selected out of 25 AC, 25 DC and 15 MTDC candidates. In this case, the net present values of investment and operation costs are \$7.14M and \$198.43M, respectively.

Case 2: In this case, most AC/DC transmission installations occur between years 11-15 for supplying the higher demand. When evaluating the transmission reliability for the pre-defined scenarios, the load shedding may be applied to find a feasible solution based on a permissible LOEP. For instance, 23.61MW of load is curtailed when the scenario S2 (i.e., AC line 8 is on outage at certain subperiods) is considered. Table XI shows that 19 AC and 6 DC transmission lines are installed. The net present values are \$2.49M and \$205.19M for investment and operation costs, respectively. The difference in total costs between this Case and Case 1 is \$2.11M which is the cost of maintaining the transmission system reliability.

TABLE IX
LIST OF OUTAGE SCENARIOS IN IEEE 118 BUS SYSTEM

Scenario	Element	Outage Season and Year	Probability
Base Case (S1)	-	-	0.9536
S2	Line 8	Winter, Year 6 & Fall, Year 14	0.0068
S3	Line 37	Spring, Year 10	0.0068
S4	Line 52	Summer, Year 8	0.0068
S5	Line 161	Winter, Year 12	0.0068
S6	Line 150	Fall, Year 11	0.0068
S7	Unit 5	Summer, Year 6	0.0031
S8	Unit 24	Fall, Year 12	0.0031
S9	Unit 29	Winter, Year 13	0.0031
S10	Unit 51	Summer, Year 15	0.0031

TABLE X
SCHEDULED TRANSMISSION LINES IN CASE 1

Line Type	From Bus	To Bus (1)	To Bus (2)	Investment Cost (Thousand \$)	Inst. Year
AC	6	113	-	272	13
AC	10	17	-	496	14
AC	15	113	-	258	15
AC	22	46	-	258	15
AC	49	59	-	242	10
DC	7	113	-	1560	15
DC	20	26	-	1747	15
DC	22	46	-	1548	14
DC	60	80	-	2420	13
MTDC	21	32	36	2460	14
MTDC	42	46	54	3073	15

TABLE XI
SCHEDULED TRANSMISSION LINE IN CASE 2

Line Type	From Bus	To Bus	Investment Cost (Thousand \$)	Inst. Year
AC	5	10	624	15
AC	7	10	496	15
AC	7	113	272	12
AC	10	17	496	15
AC	10	29	258	15
AC	13	17	350	14
AC	15	113	258	15
AC	17	25	688	14
AC	17	33	244	14
AC	18	37	258	14
AC	22	46	258	13
AC	24	26	394	15
AC	25	33	496	15
AC	30	36	258	14
AC	49	59	242	11
AC	59	67	242	15
AC	59	66	320	13
AC	60	80	1304	15
AC	65	69	128	15
DC	10	28	1548	14
DC	25	33	1747	14
DC	49	59	1535	14
DC	59	67	1535	13
DC	59	66	1600	13
DC	60	80	2420	15

V. CONCLUSIONS

A hybrid AC/DC TEP model was developed to minimize the total investment, operation, and load shedding costs in restructured power systems. Numerical examples emphasized the fact that an optimal TEP should consider both AC and DC transmission candidates that would guarantee the security and the economics of the reinforced transmission system in the base case and critical contingency situations. The TEP model presented in this paper could include all kinds of DC transmission configurations. Numerical examples show the possibility of additional savings based on the installation of DC transmission systems as compared with AC transmission systems. Such studies rationalize the high cost of installing DC transmission systems or replacing existing AC lines with DC systems in a given right of way. Therefore, the importance of the break-even distance concept should not be over-addressed in TEP studies, since the controllability of DC line flow among other factors are important in the selection of AC/DC transmission systems. In addition, the proposed TEP approach can consider the integration of remotely located, variable and large-scale renewable energy. Considering the unpredictable characteristic of wind energy, the scenario-based simulation representing a range of wind energy forecasts, can be incorporated in the proposed model as we identify a reliable and cost-effective AC/DC TEP strategy.

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Risk-Constrained Coordination of Cascaded Hydro Units with Volatile Wind Power Generation

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Abstract — This paper presents a stochastic hourly coordination strategy for wind units and cascaded hydro generation as storage to firm up the hourly dispatch in a generating company (GENCO). The proposed strategy is based on the stochastic price-based unit commitment (Stochastic PBUC) formulation which includes wind energy imbalance charges. The forecast errors of electricity market price and wind speed are simulated with the Monte Carlo method via a scenario approach. The risk-aversion constraints are considered for limiting a GENCO's financial risks when considering uncertain wind power generation. The proposed optimization model is solved by mixed-integer linear programming (MIP) and illustrative examples examine the effectiveness of the proposed risk-based coordination model for optimizing a GENCO's payoff.

Index Terms — Cascaded hydro and wind coordination, risk-aversion, stochastic price-based unit commitment

NOMENCLATURE

Variables:

EDR	Expected downside risk (\$)
h, h'	Denote a cascaded hydro unit
I_{ht}	Commitment status of hydro unit h at hour t
k	Denote an intrahour interval
$P_{C,ht}$	Coordinated generation dispatch corresponding to hydro unit h at hour t (MW)
PF^s	Payoff of scenario s (\$)
P_{ht}	Dispatch of hydro unit h at hour t (MW)
P_{htk}^s	Dispatch of hydro unit h at hour t and intrahour interval k in scenario s (MW)
P_{wt}	Dispatch of wind unit w at hour t (MW)
P_{wtk}^s	Dispatch of wind unit w at hour t and intrahour k in scenario s (MW)
$P_{wtk}^{c,s}$	Curtailed wind power of wind unit w at hour t and intrahour interval k in scenario s (MW)
$P_{\Delta,wtk}^s$	Imbalance power of wind unit w at hour t and intrahour interval k in scenario s (MW)
$P_{ \Delta ,wtk}^s$	Absolute imbalance power of unit w at hour t and

	intrahour interval k in scenario s (MW)
q_{ht}	Water discharge of hydro unit h at hour t (Hm ³ /h)
q_{htk}^s	Discharge of hydro unit h at hour t and intrahour interval k in scenario s (Hm ³ /h)
$q_{d,h(t-\tau)}$	Discharge to hydro unit h from upstream hydro units with the delay time τ at time t (Hm ³ /h)
R^s	Downside risk of scenario s (\$)
r_{ht}	Natural inflow of hydro unit h at hour t (Hm ³ /h)
s	Denote a scenario
s_{ht}	Spillage of hydro unit h at hour t in scenario s (Hm ³ /h)
t	Hour index
v_{ht}	Reservoir volume of hydro unit h at hour t (Hm ³)
w	Denote a wind unit
y_{ht}, z_{ht}	Operation status/shutdown indicator of hydro unit h at hour t
$\delta_{\Delta,wtk}^s, \delta^s$	Auxiliary binary variables

Constants:

EDR	Targeted expected downside risk target (\$)
$F_h()$	Water-to-power conversion curve of hydro unit h
NK	Number of intrahour intervals
NS	Number of scenarios
p^s	Probability of scenario s
$P_h^{\min}, P_h^{\max}$	Min/Max generation of hydro unit h
$P_{wtk}^{f,s}$	Forecasted wind power of unit w at hour t and intrahour interval k in scenario s (MW)
P_{wt}^f	Forecasted wind power unit w at hour t (MW)
$q_h^{\min}, q_h^{\max}$	Min/Max discharge limits of hydro unit h (Hm ³ /h)
RC_h	Geographic reservoir connection vector of hydro unit h
$rc_{h-h'}$	Binary variable representing the direct cascaded configuration of hydro units h and h'
RU_h, RD_h	Ramp up/down limits of hydro unit h (MW/min)
SU_h, SD_h	Start-up/shutdown cost of hydro unit h (\$)
$S_{c,h}$	Set of wind units in coordination with hydro unit h
$s_h^{\min}, s_h^{\max}$	Min/Max spillage limits of hydro unit h (Hm ³ /h)
T_0	Target payoff of a GENCO (\$)
$V_h^{\min}, V_h^{\max}$	Min/Max reservoir volume limits of hydro unit h

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$V_{0,h}, V_{NT,h}$	(Hm ³) Initial/terminal water reservoir of hydro unit h
$X(t)$	(Hm ³) Wind forecast error at time t
$Z(t)$	Random Gaussian variable with the mean equal to zero and corresponding standard deviation
α, β	ARMA constants
ρ_{BP}^s	Energy balancing price in scenario s (\$/MWh)
$\rho_{DA,t}^s$	Day-ahead energy market price at hour t in scenario s (\$/MWh)
$\rho_{RT,tk}^s$	Real-time market price at hour t and intrahour interval k in scenario s (\$/MWh)

I. INTRODUCTION

GENCO's objective is to maximize profit through market participation. Price-based unit commitment (PBUC) is a decision tool that is used by GENCOs for procuring the optimal generation bids and/or self-scheduling decisions in day-ahead by considering market price forecasts. However, GENCOs, as market participants, have no obligation to balance supply with loads. Independent system operators (ISOs) use a security-constrained unit commitment (SCUC) tool that would utilize the submitted bids to clear the day-ahead market. ISOs balance supply with loads in a secure and economic fashion.

Usually, the perfect information on the day-ahead market price and wind speed is not available. Thus, GENCOs apply a stochastic model for forecasting hourly wind speed and market price. A stochastic PBUC model is then utilized that would maximize the GENCO's payoff while minimizing its financial risks. The GENCO's payoff consists of energy sales minus the cost of energy production and imbalance penalties. The cost of imbalance energy could reduce the GENCO's potential payoff if the real-time energy dispatch does not match that of day ahead.

The GENCO's finances may be subject to major risks when considering wind energy forecast errors. In general, the daily pattern for wind energy may not coincide with that of electricity demand. Wind energy imbalance charges may be incurred if the real-time wind energy differs from the day-ahead schedule [1]-[10]. The lack of dispatchability of installed wind energy capacity would make it difficult for GENCOs to take advantage of daily differences in electricity prices.

The wind energy forecast errors could also have a major impact on the secure operation of power systems. The ISO may consider preventive and corrective actions for managing the secure operation of power systems with intermittent and volatile wind energy [11]. A stochastic model was applied in [12] to examine the impact of high penetration of wind energy on power system operations. The auto-regressive moving average (ARMA) time series model was considered in [13] to simulate the wind speed volatility. A deterministic PBUC was applied for developing fossil unit bidding strategies [14]-[16]. A stochastic PBUC solution was presented in [17]-[18] for formulating power market dynamics.

This paper proposes a risk-constrained day-ahead coordination strategy for wind and cascaded hydro (storage) units in a GENCO. Wind energy variations could occur within minutes while the day-ahead schedule is hourly; so an intrahour-based model is proposed in this paper to firm up the coordinated wind and hydro generation. The paper shows that the fast ramping and storage capabilities of cascaded hydro units could compensate wind energy volatilities. The Monte Carlo simulation is used to generate scenarios, and scenario reduction techniques are applied to eliminate low-probability scenarios and bundle similar ones to identify a limited number of effective scenarios while maintaining a reasonably good approximation of the original system [19]. The advantage of applying the Monte Carlo simulation resides in the fact that the required number of samples for a given accuracy level is independent of the system uncertainty dimension, and therefore is suitable for the simulation of power systems with a large number of uncertainties.

Scenario reduction algorithms include the fast backward method, the fast backward/forward method, and the fast backward/backward method [19]-[20]. The algorithms have different computational performance, and the chosen of algorithms for a certain problem depends on the size of the problem and the required solution accuracy. For large scenario trees, the fast backward method would provide the best computational performance with the worst accuracy. The results of the fast forward method are more accurate at the cost of longer computational time. In this paper, the fast backward/forward method is selected to reduce the number of scenarios.

The day-ahead hourly market clearing prices (MCPs) are provided as input and the uncertainty of MCPs is represented via scenarios using time series [17],[18]. There is no transmission congestion considered between wind and hydro unit locations (i.e., day-ahead hourly prices are the same for wind and hydro units.) The real-time energy balancing prices are announced daily by the ISO [21]. The energy balancing cost is the daily cost of deviation in the real-time dispatch of market entities, which is allocated as credit to other generating units for supplying energy deviations, or as credit to real-time system demand for enhancing the system reliability.

The rest of the paper is organized as follows. Section II provides the stochastic PBUC formulation with the wind-hydro intrahour coordination. Section III illustrates the proposed formulation in two examples and conclusion is presented in section IV.

II. STOCHASTIC PBUC FORMULATION

The objective of PBUC is to maximize a GENCO's payoff, which is the revenue from the sales of energy or bilateral contracts minus the operation cost of GENCO. The operation cost includes the production cost, start-up/shut down costs, and imbalance energy charges incurred by wind energy variations. In this paper, we focus on the coordination strategy of wind and hydro units, thus the hourly scheduling of other types of generating units (thermal, combined-cycle, and pumped-storage units) is not discussed [17]-[18].

In the proposed stochastic PBUC problem, there are first and second stage variables. A first stage variable is stated as a

decision variable which is made before uncertainties are disclosed, that is, yielding identical values in all scenarios such as $P_{C,ht}$. A second stage variable is scenario dependent, which can be an intrahour variable depending on t, k , and s such as $P_{\Delta,wtk}^s$. The stochastic PBUC formulation is discussed next for the wind-hydro coordination.

A. Uncoordinated Scheduling of Wind and Hydro Units

The stochastic PBUC would maximize the GENCO's expected payoff (1) subject to prevailing constraints. The first term in the objective function is the revenue from hydro and wind energy sales to day-ahead markets. The second term represents the operation cost of hydro units which includes startup and shutdown costs. The imbalance charges for wind units included in the last two terms of (1) are $P_{\Delta,wtk}^s$ paid based

on $\rho_{RT,tk}^s$ and $P_{|\Delta|,wtk}^s$ paid based on ρ_{BP}^s .

Since the coordinated scheduling of cascaded hydro and wind units is not considered here, the objective function of hydro-wind can be decoupled into two independent optimization problems. The water to power curve of hydro unit h , expressed in (2), is generally a non-linear, non-convex curve [22], in which the hydro power generation has a nonlinear correlation with the water flow through the turbine and water head. Using auxiliary binary variables, the non-convex water to power curve can be converted into the piecewise linearized model and incorporated into the proposed MIP formulation [18], [22]-[23]. There are two popular methods used in power industry for solving such MIP models including the branch-and-bound/branch-and-cut and Lagrangian Relaxation [24]. The advantages of branch-and-bound/branch-and-cut over the Lagrangian Relaxation approach for solving the MIP-based PBUC problem was discussed in details in [25]. It was shown that the branch-and-bound/branch-and-cut based method would procure near-optimal/good-enough solution with enhanced modeling and convergence acceleration strategies.

Other constraints include water discharge limits (3), reservoir volume (4), initial and terminal reservoir volume (5), water balance constraints for cascaded hydro units (6), and water spillage limits (7). Minimum on/off time and ramping up/down constraints are given in [17]-[18]. In (6), RC_h is the geographic reservoir connection vector with binary elements $rc_{h-h'}, rc_{h-h'} = 1$ if the hydro unit h' is a direct up stream of unit h ; otherwise $rc_{h-h'} = 0$. In addition, $q_{d,h(t-\tau)}^s$ in (8) represents the delayed water discharge to the hydro unit h from upstream hydro units.

Since wind speed variations could occur within minutes, the intrahour variations of wind generation is integrated into the proposed scheduling model. In this paper, the wind speed forecast is procured by the Markov chain with the probability transition matrix. Wind speed values are classified into several categories represented by the mean value at each group. The probability transition matrix can either be obtained by historical data or by probability distribution parameters of the wind speed. Using the Weibull distribution function and the

autocorrelation factor, the probability transition matrix is procured by composing an initial probability vector, a weighting matrix and a normalizing vector [26]. The probability transition matrix, which is a square matrix, defines probabilities of transiting from one wind speed category to other wind speed categories. Once the probability transition matrix is built, the wind speed time series can be procured with the Markov chain method. The wind speed forecast error is further represented by ARMA [27],[28]. Since the number of time steps for one day is not large enough (144 time steps for one day considering 10-min interval), the synthesized time series may have mean and standard deviations that are different from the corresponding values in the Weibull distribution function. Thus, the mean and the standard deviation are adjusted to procure the desired wind speed time series. The diurnal pattern strength which represents the daily pattern of wind speed is applied to the time series. The diurnal pattern has the sinusoidal form, in which the peak value indicates the ratio of the maximum wind speed to the average wind speed. The intrahour-based wind unit constraints include hourly and intrahour power generation schedule (9) and generation limits (10)-(11). The available wind energy is calculated using the wind speed forecast and used as input to PBUC. (12)-(15) incorporate $P_{|\Delta|,wtk}^s$ in the stochastic PBUC problem where M is a large positive number.

$$\begin{aligned} & \text{maximize} \quad \sum_{s=1}^{NS} p^s \cdot PF^s \\ & = \sum_{s=1}^{NS} p^s \cdot \left[\sum_{h,t} \rho_{DA,t}^s \cdot P_{ht} + \sum_{w,t} \rho_{DA,t}^s \cdot P_{wt} - \sum_{h,t} \left(y_{ht} \cdot SU_h + z_{ht} \cdot SD_h \right) \right] \\ & \quad - \sum_{w,t} \left(\frac{1}{NK} \cdot \sum_k \rho_{RT,tk}^s \cdot P_{\Delta,wtk}^s + \frac{1}{NK} \cdot \rho_{BP}^s \cdot \sum_k P_{|\Delta|,wtk}^s \right) \end{aligned} \quad (1)$$

$$P_{ht} = F_h(q_{ht}) \quad (2)$$

$$q_h^{\min} \cdot I_{ht} \leq q_{ht} \leq q_h^{\max} \cdot I_{ht} \quad (3)$$

$$V_h^{\min} \leq v_{ht} \leq V_h^{\max} \quad (4)$$

$$V_{h(0)} = V_{0,h} \quad V_{h(NT)} = V_{NT,h} \quad (5)$$

$$v_{h(t+1)} = v_{ht} + RC_h \cdot q_{d,h(t-\tau)} - q_{ht} + r_{ht} - s_{ht} \quad (6)$$

$$s_h^{\min} \leq s_{ht} \leq s_h^{\max} \quad (7)$$

$$q_{d,h(t-\tau)} = [q_{1t} \cdots q_{(h-1)t} \quad 0 \quad q_{(h+1)t} \cdots q_{Nht}] \quad (8)$$

$$P_{wt} = P_{wtk}^s + P_{\Delta,wtk}^s \quad (9)$$

$$0 \leq P_{wt} \leq P_{wt}^f \quad (10)$$

$$0 \leq P_{wtk}^s \leq P_{wtk}^{f,s} \quad (11)$$

$$P_{|\Delta|,wtk}^s - P_{\Delta,wtk}^s \geq 0 \quad (12)$$

$$P_{|\Delta|,wtk}^s + P_{\Delta,wtk}^s \geq 0 \quad (13)$$

$$P_{|\Delta|,wtk}^s - P_{\Delta,wtk}^s \leq M \cdot \delta_{\Delta,wtk}^s \quad (14)$$

$$P_{|\Delta|,wtk}^s + P_{\Delta,wtk}^s \leq M \cdot [1 - \delta_{\Delta,wtk}^s] \quad (15)$$

B. Coordinated Scheduling of Wind and Hydro Units

In this case, the coordinated scheduling of cascaded hydro unit with one or more wind units is considered for providing an hourly firm power dispatch. The first term in (16) shows the GENCO's revenue and the second term represents the operation cost of hydro unit. Since the hourly wind generation is firm, the imbalance energy charge will be zero. The unit commitment (UC) of hydro and wind units determines the hourly on/off status, and the generation dispatch provides a 10-minute solution. Thus, by coordination, the sum of intrahour wind P_{wtk}^s and hydro P_{htk}^s generation is equal to the hourly generation dispatch $P_{C,ht}$ (17). Note that $P_{C,ht}$ is a scenario-independent first-stage decision variable, which is calculated before uncertainties are imposed. The wind power (P_{wtk}^f) is dependent on the wind speed forecast. The wind power generation follows the power curve of the wind turbine, which is zero below the cut-in or above the cut-out speeds.

$$\text{maximize} \quad \sum_{s=1}^{NS} p^s \cdot PF^s \quad (16)$$

$$= \sum_{s=1}^{NS} p^s \cdot \left[\sum_h \sum_t \rho_{DA,t}^s \cdot P_{C,ht} - \sum_h \sum_t (y_{ht} \cdot SU_h + z_{ht} \cdot SD_h) \right]$$

$$P_{C,ht} = \sum_{w \in S_{C,h}} P_{wtk}^s + P_{htk}^s \quad (17)$$

$$P_{wtk}^s = P_{wtk}^{s,f} - P_{wtk}^{c,s} \quad \forall w, \forall t, \forall k, \forall s \quad (18)$$

$$q_h^{\min} \cdot I_{ht} \leq q_{htk}^s \leq q_h^{\max} \cdot I_{ht} \quad (19)$$

$$P_{ht(k+1)}^s - P_{htk}^s \leq 60 \cdot RU_h / NK \quad (20)$$

$$P_{htk}^s - P_{ht(k+1)}^s \leq 60 \cdot RD_h / NK \quad (21)$$

$$I_{ht} - I_{h(t-1)} = z_{ht} - y_{ht} \quad (22)$$

$$z_{ht} + y_{ht} \leq 1 \quad (23)$$

$$P_{htk}^s = F_h(q_{htk}^s) \quad (24)$$

$$V_h^{\min} \leq v_{htk}^s \leq V_h^{\max} \quad (25)$$

$$V_{h,0,NK}^s = V_{0,h} \quad V_{h,NT,NK}^s = V_{NT,h} \quad (26)$$

$$v_{htk}^s = v_{h(t-1)NK}^s + \frac{1}{NK} \cdot (RC_h \cdot q_{d,h(t-\tau)k}^s - q_{htk}^s + r_{htk} - s_{htk}^s) \quad \forall h, \forall t, \forall k \in [2, NK], \forall s \quad (27)$$

$$v_{ht1}^s = v_{h(t-1)NK}^s + \frac{1}{NK} \cdot (RC_h \cdot q_{d,h(t-\tau)1}^s - q_{ht1}^s + r_{ht1} - s_{ht1}^s) \quad \forall h, \forall t, \forall s \quad (28)$$

$$s_h^{\min} \leq s_{htk}^s \leq s_h^{\max} \quad (29)$$

$$q_{d,h(t-\tau)k}^s = [q_{1tk}^s \cdots q_{(h-1)tk}^s \quad 0 \quad q_{(h+1)tk}^s \cdots q_{NH,tk}^s]$$

In (18), the intrahour wind power in scenario s (P_{wtk}^s) is equal to the wind power forecast ($P_{wtk}^{f,s}$) minus the non-negative curtailed wind power ($P_{wtk}^{c,s}$). The intrahour hydro power generation P_{htk}^s is dependent on the water discharge rate which is subject to the discharge limit (19). Ramping limits (20) show that the hydro power increment in two consecutive

intrahours is limited. The wind-hydro coordination with sufficient ramping provides complimentary power from cascaded hydro units to wind units to make $P_{\Delta,wtk}^s = 0$ for all wind units in $S_{C,h}$. In (21)-(22), the hourly hydro unit commitment is related to startup and shutdown indicators.

The intrahour hydro power generation is dependent on water discharge in (23). The intrahour reservoir volume constraints of hydro units are given in (24)-(25). The intrahour reservoir volume in (26) is dependent on its previous intrahour value, discharge water flow in the present intrahour, inflow water flow from upstream hydro unit, inflow water flow, and spillage in each intrahour. In (27), the volume in the first intrahour of each hour is dependent on the volume in the last intrahour of the previous hour, the present net water flow rate, spillage, inflow and inflow from upstream hydro units. The intrahour quantities in (28)-(29) are similar to (7)-(8).

C. Risk Assessment

A GENCO would be concerned with the risk associated with its payoff when considering market price uncertainties [17]-[18]. Suppose the GENCO's day-ahead target payoff is T_0 . The payoff risk given in (30) is associated with the failure to meet the target payoff. The linear expression of risk (30) is represented in (31) by auxiliary binary variables.

$$R^s = \begin{cases} T_0 - PF^s & , \text{ if } PF^s < T_0 \\ 0 & , \text{ otherwise} \end{cases} \quad (30)$$

$$\begin{aligned} 0 \leq R^s - [T_0 - PF^s] &\leq M \cdot [1 - \delta^s] \\ 0 \leq R^s &\leq M \cdot \delta^s \end{aligned} \quad (31)$$

Here, the expected downside risk is smaller than the accepted risk level. If a GENCO is not satisfied with its payoff that is below the target, an upper expected downside risk given in (32) will be appended into the PBUC formulation.

$$EDR = E(R^s) = \sum_{s=1}^{NS} p^s \cdot R^s \leq \overline{EDR} \quad (32)$$

Hence, the original risk-neutral model is turned into a risk-constrained model by including (31)-(32). The objective is to calculate the expected payoff while keeping the expected downside risk within an acceptable range. The target $\overline{EDR}$ should be carefully designed since a tight constraint on the expected downside risk (i.e., relatively low risk $\overline{EDR}$ or high targeted payoff) could result in an infeasible solution.

D. Risk-based Stochastic PBUC Solution

The proposed stochastic PBUC for the cascaded hydro and wind unit coordination is solved by a MIP package (CPLEX).

The deterministic PBUC solution is obtained when uncertain variables are replaced by their forecasts. If the transmission network is considered, the dimension of the stochastic PBUC can increase significantly. The solution techniques based on the Benders' decomposition are considered to deal with large-scale systems by decomposing the problem into tractable master UC and hourly network evaluation subproblems [29]-[30].

III. NUMERICAL EXAMPLES

In this section, two case studies are illustrated to investigate

coordinated and uncoordinated scheduling strategies in the GENCO's portfolio with cascaded hydro and wind units. We assume no transmission congestion among wind and hydro units since they belong to the same GENCO. Detailed hydro unit data are given in Table I where a, b, c are the quadratic, linear and constant coefficients of water-to-power conversion curves respectively. The errors in market price forecast (i.e. day-ahead MCPs and energy balancing price) and the wind energy forecast uncertainty are simulated via 10,000 scenarios using the Monte Carlo simulation, and efficient algorithms are used to reduce the number of scenarios [19]-[20]. In the following, a three-hour ahead case and a day-ahead case are studied.

A. THREE-HOUR AHEAD SCHEDULING

Table I shows the system data in which a 3-hour coordination of hydro unit H1 is considered with a 200 MW wind generating unit. Table II shows the six cases in which risk constraints are not included. The forecasts for wind and day-ahead MCP and their respective forecast errors are given in Figs. 1 and 2. Based on the available forecasting techniques, the wind speed forecast would have a larger error (i.e., 10%-20%) than the price forecast (less than 10%); thus a higher standard deviation is used to represent wind speed forecast errors.

TABLE I CHARACTERISTICS OF CASCADED HYDRO UNITS

Description	H1	H2	H3	H4	H5	H6	H7
$P_{min,h}$ (MW)	9.0	4.0	17.0	30.0	9.0	2.0	19.0
$P_{max,h}$ (MW)	70.0	70.0	115.0	194.0	80.0	60.0	120.0
RD_h (MW/min)	1.17	1.17	1.92	3.23	1.33	1.00	2.00
RU_h (MW/min)	1.17	1.17	1.92	3.23	1.33	1.00	2.00
a (MW/(Hm ³ /h) ²)	-42	-30	-12.5	-31	-38.8	-31.2	-14.4
b (MW/(Hm ³ /h))	113	106.2	78.8	155.1	121.75	98.42	85.5
c (MW)	-1.82	-6.0	7.26	7.5	-2.64	-7.23	6.45
$q_{min,h}$ (Hm ³ /h)	0.1	0.1	0.13	0.15	0.1	0.1	0.15
$q_{max,h}$ (Hm ³ /h)	1.0	1.0	2.0	2.0	1.0	1.0	2.0
r_h (Hm ³ /h)	0.4	0.3	0.2	0.3	0.3	0.2	0.12
$s_{min,h}$ (Hm ³ /h)	0.1	0.1	0.2	0.2	0.1	0.1	0.2
$s_{max,h}$ (Hm ³ /h)	1.0	1.0	2.0	2.0	1.0	1.0	2.0
$V_{0,h}$ (Hm ³)	10.0	8.0	17.0	11.0	10.0	9.0	18.0
$V_{NT,h}$ (Hm ³)	10.0	8.0	17.0	11.0	10.0	9.0	18.0
$V_{min,h}$ (Hm ³)	7.0	4.0	10.0	7.0	6.0	5.0	12.0
$V_{max,h}$ (Hm ³)	15.0	13.0	24.0	16.0	16.0	14.0	30.0
Catchment Index	1	1	1	1	2	2	2
Upstream Unit	-	-	H2,H1	H3	-	H5	H6
Downstream Unit	H3	H3	H4	-	H6	H7	-
Delay Time	2	2	2	2	2	2	2

TABLE II THREE-HOUR AHEAD CASES

Case	Coordinate	Stochastic	Energy Balancing Price (\$/MWh)
1	No	No	5.00
2	No	Yes	5.00
3	No	No	50.00
4	No	Yes	50.00
5	Yes	No	-
6	Yes	Yes	-

Fig. 1 Wind speed forecast

Fig. 2 Day-ahead MCP forecast

The wind speed forecast follows the Weibull distribution function, with the Weibull constant equal to 2 and the average wind speed equal to 9.1 m/s. The 3-hour pattern strength is 0.34 at the peak hour 3, which is the ratio of the peak wind speed to the average wind speed during the 3-hour period. ARMA model is used to simulate the wind speed forecast error [27]-[28]. Since the autocorrelation factor (ACF) and partial autocorrelation factor (PACF) decrease dramatically as the time lag increases, a lower order ARMA (1,1) represented in (33) is used.

$$X(t, k) = \alpha \cdot X(t, k-1) + \beta \cdot Z(t, k-1) + Z(t, k)$$

$$k \in [2, NK] \quad (33)$$

$$X(t, 1) = \alpha \cdot X(t-1, NK) + \beta \cdot Z(t-1, NK) + Z(t, 1)$$

ARMA constants can be procured by minimizing the difference in the root mean square error (RMSE) between the simulated ARMA model and the wind speed measurement data [28]. In this paper, it is assumed that the ARMA constants are $\alpha = 0.88$, $\beta = -0.34$. The standard deviation represented by the truncated Gaussian distribution function $[-\sigma, +\sigma]$ in which σ ranges from 3% of the wind speed forecast for a 10-minute lag time to 11% of the wind speed forecast for a 3-hour lag time, which shows that the forecast error increases linearly in the forecast horizon. Once a large number of scenarios are generated, the boundary levels are derived by the maximum deviations of wind speed scenarios located above/below the forecast as shown in Fig. 1.

Similarly, autoregressive integrated moving average (ARIMA) is used to procure the price forecast error, which is a non-stationary stochastic process. The non-stationary forecasted time series can be represented by periodic and stationary time series. In this case, the trend of periodic component is shown in Fig. 2, while the standard deviation of the stationary component represented by the truncated Gaussian distribution function $[-\sigma, +\sigma]$ is 1% for a 10-min lag and 5% for a 3-hour lag [31]. The standard deviation of stationary components increases linearly with the time-lag. The 3-hour pattern strength is 0.28, and the peak price hour is 1:50. The average price is 19\$/MWh. The boundary levels in Fig. 2 show the maximum deviation of random variables located above/below the forecast at each time interval.

The number of scenarios is reduced to 3 with the corresponding probabilities of 0.5188, 0.1822, and 0.2990, respectively. The probabilities are procured by eliminating scenarios with very low probabilities and bundling scenarios that are very close in terms of statistical metrics [19]-[20]. The simulation results are compared in coordinated and uncoordinated scheduling cases. The payoffs for Cases 1-6 are summarized in Table III with a target payoff of \$6,000. The

results are discussed as follows.

TABLE III PAYOFFS IN THE THREE-HOUR AHEAD PROBLEM (\$)

	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6
Imbalance Costs	1,395	1,598	3,055	933	0	0
Wind Energy Sales	6,153	6,280	4,354	4,348	4,529	4,713
Wind Energy Payoff	4,758	4,682	1,299	3,415	4,529	4,713
Hydro Energy Payoff	2,111	2,275	2,111	2,275	2,098	1,637
Total Payoff	6,869	6,957	3,410	5,690	6,627	6,350
EDR	45	19	2,584	348	230	0

A1) Uncoordinated scheduling of wind and hydro units

Figs. 2-6 show the dispatch results for the uncoordinated scheduling Cases 1-4 listed in Table II. In Cases 1 and 2, the imbalance energy charges have a smaller impact on payoff since the energy balancing price is 5 \$/MWh which is much lower than average MCPs.

Fig. 3 Three-hour ahead schedule in Case 1

Fig. 4 Three-hour ahead schedule in Case 2

Fig. 5 Three-hour ahead schedule in Case 3

We offer the following observations.

- *Deterministic versus stochastic scheduling solutions*

The imbalance energy, its cost, and the wind energy curtailment are higher in the stochastic solution. Figs. 3-4 show that there are 3.27 MWh and 6.21 MWh of curtailments in Cases 1 and 2, respectively. Comparing Cases 3 and 4, the imbalance energy in Case 3 is 10.22 MWh while it increases to 13.13 MWh in Case 4. The imbalance energy charge in Case 3 is \$711.55 which increases to \$933.02 in Case 4. Figs. 5-6 show 59.98 and 63.30 MWh of curtailment in Case 3 and 4 respectively. At certain intrahours, the wind power generation is not the same as its hourly dispatch which indicates that the wind power is curtailed to minimize imbalance energy charges. Table III shows that the stochastic scheduling solutions would lead to higher payoffs in

the uncoordinated cases. The hydro unit payoff is also increased in the stochastic solutions; however, the wind unit payoff calculated by the energy balancing price increases from Case 3 to 4, and decreases from Case 1 to 2. The deterministic payoffs and imbalance energy costs in Table III are forecast values which are procured by applying deterministic values to uncertain parameters in the market.

- *Impact of energy balancing price on imbalance energy*

As the energy balancing price increases, the imbalance energy decreases. Here, the imbalance energy is decreased from 55.20 MWh in Case 1 to 10.22 MWh in Case 3. The same applies to Cases 2 and 4.

Fig. 6 Three-hour ahead schedule in Case 4

- *Impact of energy balancing price on wind energy curtailment*

Comparing Cases 1 and 2 with Cases 3 and 4, it is seen that higher energy balancing price increases the wind energy curtailment to avoid imbalance energy charges. The wind energy curtailment increases from 3.27 MWh in Case 1 to 59.98 MWh in Case 3. A similar observation can be procured for stochastic Cases 2 and 4.

- *Impact of energy balancing price on total payoff*

Table III shows a lower payoff when the energy balancing price is higher. A lower payoff occurs when the wind energy unit payoff is lowered due to the imposed energy balancing price. The comparison shows that the stochastic scheduling solution demonstrates a higher payoff once energy balancing prices are higher. The increase in payoff from Case 1 to Case 2 is 1.3% while the increase in payoff from Case 3 to Case 4 is 66.8%.

- *EDR in deterministic and stochastic cases*

The EDR of the deterministic solution measures the risk of the deterministic solution in terms of scenarios. The EDR for a target payoff of \$6,000 is \$45.62 for the deterministic solution (Case 1) and \$19.50 for the stochastic solution (Case 2). The difference of \$26.12 shows a lower risk for the stochastic scheduling solution. Thus, the stochastic solution would increase the total payoff and decrease the financial risks as compared with the deterministic scheduling solution.

A2) Coordinated wind and cascaded hydro units

Cases 5 and 6 investigate the benefits of coordinated dispatch of cascaded hydro and wind units. In comparison with Cases 1-4, imbalance energy charges are not incurred in Cases 5 and 6 since the scheduling coordination of wind and cascaded hydro units will firm up the output and $P_{\Delta, wtk}^s$ is zero. The following observations are deducted by comparing coordinated and uncoordinated scheduling cases.

- *Impact of stochastic analysis*

Figs. 7 and 8 show a wind energy curtailment of 12.42 MWh and 37.08 MWh in Cases 5 and 6. Again, the wind energy curtailment is higher in the stochastic scheduling cases.

- *Impact on the total payoff and risk*

The coordinated Cases 5 and 6 in Table III show that the stochastic solution would result in lower risks and total payoffs. In Table III, although the downside risk is decreased in the stochastic solution, the total payoff is decreased by 4.2%. In addition, the cascaded hydro unit payoffs are decreased in the coordinated scheduling cases. Hence, the scheduling coordination may not be economically beneficial for cascaded hydro units. Comparing Cases 4 and 6, it is shown that higher energy balancing prices will lower the risk and increase the expected payoff with the coordination. However, Cases 2 and 6 show that the coordination may not improve the GENCO's expected payoff in a lower energy balancing price.

Fig. 7 Three-hour ahead schedule results in Case 5

Fig. 8 Three-hour ahead schedule results in Case 6

Fig. 9 Payoffs with energy balancing price

Fig. 9 presents the payoffs in Cases 4 and 6. For the uncoordinated Case 4, the expected payoff decreases with an increase in energy balancing price until the price is high enough to eliminate wind power deviations; so the payoff is the highest at the zero energy balancing price. In this case, the maximum expected payoff is \$7,374.06 at $\rho_{BP} = 0$ \$/MWh, and the minimum payoff is \$4,619.51 starting roughly at $\rho_{BP} = 800$ \$/MWh. In the coordinated Case 6, the expected payoff is constant since the energy balancing prices have no impact on payoffs. The uncoordinated and coordinated scheduling cases are equally profitable in Fig. 9 where the two curves cross

($\rho_{BP} = 18.2$ \$/MWh). Thus, the coordination provides a higher return when the energy balancing price is higher than 18.2 \$/MWh.

B. DAY-AHEAD SCHEDULING

We consider the day-ahead schedule in a GENCO with 3 wind farms (W1-W3) and 7 hydro units in two catchments (H1-H4 in catchment 1 and H5-H7 in catchment 2). The wind farm capacities are 200MW, 200MW and 250MW, respectively and the wind power curves are shown in Fig. 10. We assume W1 and W2 are located near catchment 1 and W3 is close to catchment 2. Thus, the coordinated scheduling of W1-H2, W2-H3, and W3-H6 is considered.

Fig. 10 wind turbine power curves

The hydro unit characteristics are given in Table I, and market prices and wind speeds are forecasted as discussed before. 10,000 scenarios are generated originally and 30 are retained after scenario reduction. In this case study, the standard deviation of forecast error of wind speeds increases linearly from 3% of forecasted wind speed for the 1-hour lag time to 11% of forecasted wind speed for the 24-hours lag time. The diurnal strength pattern is 0.34 with the average wind speed 9.1 m/s and hour of peak wind speed of 24. The wind generation forecast error of W3 is shown in Fig. 11. Here, the wind power forecast error is higher than that of the wind speed because of non-linear and non-convex characteristics of the wind turbine power curve. Alternatively, the forecast error of wind generation can be simulated by fat tailed Beta distribution function in which the parameters are dependent on wind generation levels [32].

Fig. 11 Wind power forecast error of W3

TABLE IV CASES CONSIDERED IN THE DAY-AHEAD SCHEDULING						
Case	Coordination	W1	W2	W3	Stochastic	Risk-Constrained
1	No	-	-	-	Yes	No
2	No	-	-	-	Yes	Yes
3	Yes	H2	H3	H6	Yes	No
4	Yes	H2	H3	H6	Yes	Yes

The wind generation forecast error is procured based on the wind speed forecast error and four cases are studied as shown in Table IV. The energy balancing price of 30\$/MWh is used in all four cases and risk constraint is imposed as given in Table IV. The stochastic PBUC has 160,010 continuous variables, 18,576 binary variables, and 171,685 constraints, which is solved in about 30 seconds with an Intel 2.13 GHz personal computer. The impact of coordination and risk constraints are evaluated on the GENCO's hourly scheduling, generation dispatch, and payoff. The results are discussed as follows.

- *Impact on unit commitment (UC)*

Tables V-VIII show the UC results for units H2, H5 and H6 in Cases 1-4. Comparing Cases 2-4 with Case 1, the hourly unit commitment changes are highlighted in Tables VI-VIII. The changes in Table VI are due to the inclusion of risk constraint. The UC solutions for units H2 and H6 are changed to satisfy the EDR limit for the given target payoff at the cost of lowering the payoff. The changes listed in Table VII are due to coordination. Similar to Case 2, the changes listed in Table VIII are due to risk constraints and coordination in Case 4. Since H5 is located on the upstream of H6 with a water discharge flow delay time of 2 hours, the scheduling coordination of W3-H6 when considering the risk constraint would require the commitment of H5 at hour 4 as opposed to hour 2. H5 is shutdown at the end of the day to satisfy terminal reservoir requirements. In Case 4, H2 and H6 are committed at all hours for coordination with wind units.

TABLE V UC FOR H2, H5 AND H6 IN CASE 1

Unit	Hours (1-24)																							
H2	0	0	0	0	1	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	
H5	1	1	1	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	
H6	0	1	1	0	1	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	

TABLE VI UC FOR H2, H5 AND H6 IN CASE 2

Unit	Hours (1-24)																							
H2	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0
H5	1	1	1	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0
H6	1	1	1	0	1	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0

TABLE VII UC FOR H2, H5 AND H6 IN CASE 3

Unit	Hours (1-24)																							
H2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
H5	1	1	1	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0
H6	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1

TABLE VIII UC FOR H2, H5 AND H6 IN CASE 4

Unit	Hours (1-24)																							
H2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	
H5	1	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	
H6	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	

- *Impact on generation dispatch*

Figs. 12-13 show the generation dispatch of W1 in Cases 1 and 3. The generation dispatch of W1 in Cases 2 and 4 have similar trends and thus are not presented here. As expected, the generation dispatch follows the trend in wind energy scenarios. Without any coordination, the optimal generation dispatch incurs an average wind power curtailment of 12.99 MW. The expected wind energy imbalance is 27.58 MWh for W1. With coordination, the average wind power curtailment is 3 MW which is 76.9% lower than that without coordination. The hydro

unit generation is represented by the distance between dots and the generation dispatch curve. There is no imbalance wind energy because hydro units provide intrahour power to complement the wind unit generation.

Fig. 12 Day-ahead generation dispatch of W1 in Case 1

Fig. 13 Day-ahead generation dispatch of W1 in Case 3

- *Impact on payoff*

Table IX shows expected payoffs and downside risks with a target payoff of \$900,000. If the expected downside risk of \$7,648 in Case 1 is unacceptable, the GENCO can control the associated risk level with the proposed method. In order to obtain the minimum allowable downside risk, the risk will be penalized in the objective function with a large penalty factor. Accordingly, the minimum downside risk is \$6,855 with an expected payoff of \$896,730. In Case 2, an acceptable risk level is \$7,000 with a payoff of \$897,498. In comparison with Case 1, the risk is reduced by $(7,648 - 7,000) / 7,648 = 8.48\%$ at the cost of reducing the expected payoff by $(\$897,956 - \$897,498) / \$897,956 = 0.05\%$.

In Case 3, EDR is \$3,082 with an expected payoff of \$914,083. The minimum EDR is \$2,997 with an expected payoff of \$913,747 which is procured by penalizing the risk into the objective. In Case 4, we set the maximum EDR to \$3,000 and obtain an expected payoff of \$913,756, which shows a reduction in risk of 2.66% at the cost of 0.04% reduction in payoff, as compared to Case 3.

Table IX shows that the scheduling coordination will increase the expected payoff and decrease the downside risk. By setting EDR in an acceptable range in Cases 2 and 4, the expected payoff in the coordinated Case 4 will be higher. Table IX shows that the acceptable EDR in Case 4 is far less than that in Case 2; hence scheduling coordination will decrease EDR and increase the expected payoff.

TABLE IX EXPECTED PAYOFF AND DOWNSIDE RISK FOR ALL CASES (\$)

Case	Expected Payoff	Downside Risk
1	897,956	7,648
2	897,498	7,000
3	914,083	3,082
4	913,756	3,000

IV. CONCLUSIONS

The proposed study and its results demonstrate that the scheduling coordination of cascaded hydro and wind units can firm up wind energy, increase expected payoffs, and reduce downside risks of GENCOs. When wind and hydro units are not coordinated, energy balancing prices would affect the generation dispatch decisions. Also, the expected payoff will decrease when the energy balancing price is increased. It is shown that depending on the energy balancing price, the payoff in uncoordinated hydro and wind unit cases may be larger than that in coordinated cases. Hence, the GENCO may decide to schedule cascaded hydro and wind units in either coordinated or uncoordinated configurations, which depends on the accuracy of forecast of the day-ahead energy balancing price. The wind energy curtailment will increase with energy balancing prices, in order to avoid imbalance energy charges. Thus, the coordination of wind and hydro scheduling would lower the wind curtailment and increase the GENCO's payoff by mitigating the imbalance energy charges. The coordination will result in lower wind curtailment in both stochastic and deterministic scheduling solutions. It is shown that the hydro unit payoffs will decrease once they are coordinated with wind energy units. However, eliminating the imbalance energy charges for wind energy units in coordinated cases could increase the total payoff of a GENCO at certain energy balancing prices.

The stochastic scheduling solution would lower the GENCO's expected downside risk as compared to the deterministic scheduling solution. In addition, in uncoordinated cases, the stochastic scheduling solution will result in higher payoffs for a GENCO as compared to the deterministic scheduling solution.

Other storage technologies, such as the vanadium redox-flow battery (VRB) storage and pumped-storage hydro, may also be used to firm up wind energy. However, storage efficiency cycle, storage capacity, reservoir balance, and limited number of charge/discharge cycles per day could increase wind power curtailments and limit the GENCO's payoffs.

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Generation risk assessment in volatile conditions with wind, hydro, and natural gas units

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ABSTRACT

This paper studies a generating company (GENCO)'s midterm (a few months to a year) scheduling payoffs and risks in volatile operating conditions. The proposed algorithm considers the integration of intermittent wind units into a GENCO's generation assets and coordinates the GENCO's hourly wind generation schedule with that of natural gas (NG) units (with volatile gas prices) and hydro units (with water inflow forecast) for maximizing the GENCO's payoff. The proposed midterm GENCO model applies market price forecasts to the risk-constrained stochastic price-based unit commitment (PBUC) for calculating the GENCO's risk in energy and ancillary services markets. The proposed PBUC minimizes the cost of (a) NG contracts, storage, startup and shutdown, (b) startup and shutdown of cascaded hydro units, and (c) penalty for defaulting on the scheduled power delivery. Simulation results show that the diversification of generating assets including bilateral contracts (BCs) could enhance the GENCO's midterm planning by increasing the expected payoff and decreasing the financial risk.

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1. Introduction

Generating companies (GENCOs) are self-interested entities in restructured power systems, which are responsible for the midterm operation planning of their respective generating units. This paper proposes an optimization framework for a GENCO's midterm coordinated operation planning with wind, hydro, and NG units.

When considering the volatility of NG prices, it is imperative to include the NG transmission system and the uncertainties related to NG transmission system interruptions, which could further impose limits on the availability of NG and the scheduling of NG-fired units by GENCOs. Ref. [1] presented the impact of NG infrastructure contingencies on power system operations and discussed the role of renewable resources on reducing the dependence of electricity infrastructure on the NG infrastructure. Ref. [2] presented an integrated model for assessing the impact of electricity and NG networks on power system security. The integrated model incorporated the simplified linear NG network constraints into the optimal solution of SCUC. Ref. [3] included nonlinear NG network equations in the security-constrained unit commitment (SCUC) problem using a decomposition approach. Ref. [4] proposed a component-based model for the scheduling of combined-cycle gas units by mixed-integer programming. Ref. [5] considered a linear

NG network model for representing NG network constraints and interruption uncertainties in evaluating GENCO's risk.

Wind power is the fastest growing renewable energy resource since it is clean, indigenous, fast to deploy and economically competitive with other generation types. However, the intermittent and volatile nature of wind energy should be properly modeled in operational planning analyses. The stochastic SCUC solution with integrated wind energy has usually focused on the short-term operation planning. The effect of wind energy uncertainty on the day-ahead planning was included in SCUC [6]. The impact of wind generation on regulation and load following was analyzed in [7]. Ref. [8] studied the impact of high wind penetration on the day-ahead scheduling. Ref. [9] investigated the short-term wind energy forecast errors on the day-ahead generation scheduling. However, a GENCO would be concerned with its midterm risks when inexpensive and volatile wind units are utilized. The proposed algorithm for the midterm operation planning of a GENCO would consider the volatility of wind units when minimizing the risk of forecast errors for water inflows in hydro units and market prices of electricity and gas.

Forward BCs may hedge GENCO's volatilities. However, a large BC in a volatile environment could expose GENCOs to high penalty payments for defaulting on contracts. In [10], a stochastic decision framework for energy procurement of large customers was proposed. The supply portfolio was optimized considering uncertain pool prices, BCs, and self generation. CVaR was used to formulate risks, and the risk term was added to the objective function with

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Nomenclature

Indices

h	index of hydro units
j	index of NG units
l	index of hydro catchments
n	index of NG contracts
s	index of scenarios
t	index of time in BC period (h)
u	index of NG storage facilities
w	index of wind units
z	index of BC periods

Dimensions

NCM	number of hydro catchments
NGC	number of NG contracts
NNG	number of NG-fueled units
NGS	number of NG storage facilities
NH_l	number of hydro units of a hydro catchment l
NS	number of scenarios
NT	number of hours
NW	number of wind units
NZ	number of BC periods under study

Sets

SBC	set of units assigned to honor a BC
ST_z	set of hours for the BC period z

Variables

C_{ns}	cost of NG usage from contract n in scenario s
$C_{pen,zs}$	penalty for deficient BC in period z
C_{us}	cost of NG usage from storage facility u in scenario s
$E_{bc,z}$	BC in period z
$E_{bc,max}$	upper energy limit for the flexible BC
$E_{bc,min}$	lower energy limit for the flexible BC
$E_{def,zs}$	deficient BC in period in scenario s

$E_{del,zs}$	delivered BC in period z and scenario s
I	commitment state
OR	operating reserve
P	power generation
$P_{\psi,wts}$	wind generation of unit w at time t and scenario s
P_{bc}	power generation to satisfy BC
PF_s	GENCO's payoff in scenario s
$R_{bc,z}$	BC revenue in period z
$RISK_s$	GENCO's downside risk in scenario s
SD	shutdown cost
SR	spinning reserve
SU	startup cost
TP	generation capacity offered to a day-ahead market
W_{zs}	binary index indicating that the GENCO is defaulting on its BC at period z under scenario s
λ	lagrange multiplier
ψ_{wts}	stochastic speed of wind unit w at hour t in scenario s

Constants

A_w	area swept by the rotor of wind unit w
$c_{p,w}$	power coefficient of wind unit w
EDR	expected downside risk
$\overline{EDR}$	upper limit for expected downside risk
p_s	probability for a scenario s
T_0	target payoff of a GENCO
$\rho_{air,w}$	density of air at region where wind unit w is located
ρ_{bc}	BC price
$\rho_{g,ts}$	market price for energy at time t in scenario s
$\rho_{or,ts}$	market price for operating reserve at time t in scenario s
ρ_{pen}	penalty price for a deficient BC
$\rho_{sr,ts}$	market price for spinning reserve at time t in scenario s
$v_{Cl,w}$	cut-in wind speed of wind unit w
$v_{CO,w}$	cut-out wind speed of wind unit w
$v_{R,w}$	rated wind speed of wind unit w

a weight factor to address tradeoffs between cost and risk minimization. Ref. [11] presented the optimal bidding strategy as a non-linear mathematical program with equilibrium constraints. The GENCO's payoff was maximized and expected offers, uncertain system loads, and BCs were modeled as constraints.

In this paper, we consider the simultaneous coordination of BC with several inexpensive but uncertain units in a GENCO for hedging payoffs. The proposed model, which is an extension of [5], considers the uncertain wind model and utilizes the risk-constrained stochastic PBUC framework. A GENCO with uncertain wind, hydro, and NG resources would use the proposed midterm planning for analyzing market risks and coordinating the hourly commitment schedules with BCs for maximizing the GENCO's financial payoffs.

The paper is organized as follows. The risk-based mathematical model is described in Section 2. The MIP-based PBUC solution is introduced in Section 3. Case studies are given in Section 4. Section 5 concludes this paper.

2. Risk-based MIP model

This section starts with defining the objective function of the risk-based MIP model. Then the unit, BC coordination and risk constraints are described.

2.1. Objective function

The stochastic operational planning problem is modeled using Monte-Carlo scenarios. The objective (1) is to maximize the

expected payoffs over all scenarios. The payoff is the difference between revenues and expenses. The revenue (2) is due to sales of energy, spinning reserves, and operating reserves by NG, cascaded hydro, and wind units and the income from BC sales. The cost (3) includes that of (i) NG contracts, storage, startup and shutdown of NG units; (ii) startup and shutdown for cascaded hydro units; (iii) penalty for defaulting on the scheduled generation delivery.

$$\text{Max} \sum_{s=1}^{NS} p_s \cdot PF_s = \sum_{s=1}^{NS} p_s \cdot \{REVENUE_s - COST_s\} \quad (1)$$

where

$$\begin{aligned} REVENUE_s = & \sum_{j=1}^{NNG} \sum_{t=1}^{NT} [\rho_{g,ts} \cdot TP_{jts} + \rho_{sr,ts} \cdot SR_{jts} + \rho_{or,ts} \cdot OR_{jts}] \\ & + \sum_{l=1}^{NCM} \sum_{h=1}^{NH_l} \sum_{t=1}^{NT} [\rho_{g,ts} \cdot TP_{hts} + \rho_{sr,ts} \cdot SR_{hts} + \rho_{or,ts} \cdot OR_{hts}] \\ & + \sum_{w=1}^{NW} \sum_{t=1}^{NT} [\rho_{g,ts} \cdot TP_{wts} + \rho_{sr,ts} \cdot SR_{wts} + \rho_{or,ts} \cdot OR_{wts}] + \sum_{z=1}^{NZ} R_{bc,z} \quad (2) \end{aligned}$$

and

$$\begin{aligned} COST_s = & \sum_{n=1}^{NGC} C_{ns} + \sum_{u=1}^{NGS} C_{us} + \sum_{j=1}^{NNG} \sum_{t=1}^{NT} [SU_{jts} + SD_{jts}] \\ & + \sum_{l=1}^{NCM} \sum_{h=1}^{NH_l} \sum_{t=1}^{NT} [SU_{hts} + SD_{hts}] + \sum_{z=1}^{NZ} C_{pen,zs} \quad (3) \end{aligned}$$

2.2. Unit constraints

The mathematical formulation for cascaded hydro, NG units, NG infrastructure constraints and wind units constraints are given as follows:

- Cascaded Hydro Constraints
 - (a) Generator availability constraint.
 - (b) Energy and ancillary services supplied.
 - (c) Water-to-power conversion.
 - (d) Operating regions (water discharge limits).
 - (e) Reservoir volume limits.
 - (f) Initial and terminal reservoir volumes.
 - (g) Water balance constraint.
 - (h) Minimum on/off time and ramping up/down constraints.
- NG Unit Constraints
 - (a) Generator availability constraint.
 - (b) Fuel consumption and emission allowance constraints for groups of NG units.
 - (c) Energy and ancillary services supplied.
 - (d) Minimum on/off time and ramping up/down constraints.
- NG Infrastructure Constraints

The hourly and yearly linear network flow models considering limits on pipelines, sub-areas, power plants, and units are adopted for the midterm stochastic model. The detailed description for the constraints regarding NG units, NG contracts, infrastructure and cascaded hydro units could be found in [5] and [13].

- Wind Unit Constraints

The nonlinear wind speed to power conversion curve is given in (4) and $P_{\psi, wts}$ is given as an input. The wind generation w is subject to (5)

$$P_{\psi, wts}(\psi_{wts}) = \begin{cases} 0 & \text{if } \psi_{wts} < v_{Cl, w} \\ 0.5c_{p, w} \cdot \rho_{air, w} \cdot A_w \cdot (\psi_{wts})^3 & \text{if } v_{Cl, w} \leq \psi_{wts} < v_{R, w} \\ P_{R, w} & \text{if } v_{R, w} \leq \psi_{wts} < v_{CO, w} \\ 0 & \text{if } \psi_{wts} \geq v_{CO, w} \end{cases} \quad \forall w, \forall s \quad (4)$$

$$I_{wts} \cdot P_{min, w} \leq P_{wts} \leq I_{wts} \cdot P_{\psi, wts}(\psi_{wts}) \quad \forall k, \forall s \quad (5)$$

The auto-regressive moving average (ARMA) based approach [12] would provide wind energy scenarios forecasts. The wind power forecast errors are simulated using ARMA series. The series parameters are fitted via an optimization algorithm considering the difference between old hourly forecasts and actual realized values. The obtained ARMA series is sampled in order to obtain the forecast errors for each time step t for each scenario s . Finally, the wind power Monte-Carlo scenarios are taken to be the sum of the wind power forecasts and the sampled wind power forecast errors for the study horizon. The wind forecast and three Monte Carlo weekly wind power scenarios are depicted in Fig. 1.

2.3. Bilateral contracts and coordination

BC, transacted by external generating entities, can be either physical or financial. BC characteristics include:

- (1) NZ: 52 weeks for a one year study;
- (2) ρ_{pen} : BC penalty price (\$/MW h) over the contract length.

A flexible $E_{bc, z}$ at period z given in (6) can be adjusted by a GENCO for enhancing its payoff.

$$E_{bc, min} \leq E_{bc, z} \leq E_{bc, max}, \quad \forall z \quad (6)$$

A flat case is represented by $E_{bc, min} = E_{bc, z} = E_{bc, max}$. Accordingly, the GENCO receives a payment of $R_{bc, z}$ as

$$R_{bc, z} = \rho_{bc} \cdot E_{bc, z}, \quad \forall z \quad (7)$$

GENCOs can offer excess generation to the day-ahead market as shown in the first three terms of (2). The GENCO's penalty payment is represented by the last term of (3) if the GENCO defaults on its BC given in following equation:

$$E_{def, zs} = \max\{0, (E_{bc, z} - E_{del, zs})\}, \quad \forall z, \forall s \quad (8)$$

The MIP formulation of (8) would use an external binary variable W , where

$$0 \leq E_{def, zs} - [E_{bc, z} - E_{del, zs}] \leq M \cdot [1 - W_{zs}]$$

$$0 \leq E_{def, zs} \leq M \cdot W_{zs}, \quad \forall z, \forall s \quad (9)$$

Here M is a large positive number and W_{zs} is the binary index which is equal to 1 when $E_{bc, z} \geq E_{del, zs}$, and is 0 otherwise. The penalty $C_{pen, zs}$ is given as

$$C_{pen, zs} = \rho_{pen} \cdot E_{def, zs}, \quad \forall z, \forall s \quad (10)$$

Since the penalty is considered in the objective function, (11) would replace (9) to simplify the presentation.

$$[E_{bc, z} - E_{del, zs}] \leq E_{def, zs}, 0 \leq E_{def, zs}, \quad \forall z, \forall s \quad (11)$$

At the optimal solution, one of the constraints in (11) is binding. Multiple generating units in a GENCO could be considered for satisfying BC as given in the following equation

$$\sum_{j \in SBC} \sum_{t \in ST_z} P_{bc, jts} + \sum_{h \in SBC} \sum_{t \in ST_z} P_{bc, hts} + \sum_{w \in SBC} \sum_{t \in ST_z} P_{bc, wts} = E_{del, zs}, \quad \forall z, \forall s \quad (12)$$

The BC coordination would be based on the level of uncertainty, i.e. a wind unit dispatch could be coordinated with NG units, which are also subject to NG interruption and NG price uncertainty. A typical generating unit dispatch (13) includes its BC supply and the energy offered to the day-ahead market at time t under contract period z and scenario s .

$$P_{bc, jts} + TP_{jts} = P_{jts}, \quad \forall z, \forall s, \forall t \in ST_z \quad (13)$$

2.4. Consideration of financial risk

The stochastic formulation described above is a risk-neutral model that is only concerned with the optimization of expected payoff. However, a GENCO may also be concerned with its risk. A GENCO may set a target payoff T_0 and the risk associated with its decision is measured by the failure to meet the target. If the payoff for a scenario is larger than the target, the associated downside risk is zero; otherwise, it is the difference between the payoff and its target as

$$RISK_s = \max\{0, T_0 - PF_s\}, \quad \forall s \quad (14)$$

The expected downside risk should be lower than a target risk,

$$\sum_{s=1}^{NS} p_s \cdot RISK_s \leq \overline{EDR} \quad (15)$$

subject to risk constraints given in [14].

3. Solution method

The objective function (1) is subject to constraints (2)–(15) as given above. The original problem is first relaxed from risk

Fig. 1. Wind power forecasts and Monte Carlo simulations.

constraints using Lagrangian multipliers. Then, it is decomposed into subproblems for NG, hydro, and wind units [5]. The algorithm flowchart is shown in Fig. 2. The subproblems for NG, cascaded hydro, and wind units are solved in parallel when the coupling risk constraint is relaxed. Each subproblem related to an individual unit is solved to maximize the expected payoff of all scenarios in the entire study horizon. The Lagrange multipliers are updated using the subgradient method and iterations continue until the difference between the objective functions in two consecutive iterations is smaller than a predefined threshold and an optimal or suboptimal solution is reached.

The GENCO's risk evaluation problem is solved by assuming an initial target payoff without considering risk constraints. The proposed solution would include the expected risk level. If the risk were not within the GENCO's tolerance, the GENCO would add the risk-constraints. The process will continue until the difference between the objective function values in two consecutive iterations is smaller than a predefined threshold. If the risk were still out of GENCO's tolerance, the GENCO would decrease its target payoff and repeat the process. The Lagrange multipliers of the risk-neutral solution are recorded and set at the beginning of risk-constrained algorithm to decrease the solution time of the risk-constrained case. Further discussions on the solution method is provided in [5].

4. Case studies

We first present a 3-h example to introduce the coordination for one wind and one NG unit. A more realistic example considering a GENCO with 8 NG, 4 cascaded hydro units, and 3 wind units will also be discussed.

4.1. Three-hour example

Consider a 3-h example of a GENCO with one wind and one NG unit. There are two scenarios with a 50% probability for each scenario. Assume wind forecasts of 100 MW, 150 MW, 170 MW at hours 1–3 in the first scenario, and 80 MW, 130 MW, 150 MW at hours 1–3 in the second scenario. The NG unit has a generation cost of \$19/MW h with min/max capacity of 55 MW and 200 MW, respectively. The day-ahead energy prices are \$20/MW h and \$15/MW h for scenarios 1 and 2, respectively. The following cases are studied:

- Case 1: No coordination of generating units and no BC.
- Case 2: Fixed BC without coordination of units.
- Case 3: Wind-NG unit coordination with a fixed BC.
- Case 4: Wind-NG unit coordination with an optimized BC.

Fig. 2. Flowchart of the MIP solution method.

4.1.1. Case 1

This case serves as the base case. All available wind energy is utilized since the NG unit is profitable only in the first scenario when the given scenario day-ahead energy prices and NG unit generation cost is considered. The expected payoff is \$6900 in Table 1 and the target payoff is the same as the expected payoff with a downside risk of \$750. This target payoff is used in the following cases.

4.1.2. Case 2

A BC of 400 MW h with an energy price of \$18/MW h and penalty price of \$30/MW h is added. The hourly schedule based on PBUC is given in Table 2. The BC price is lower than that of energy in scenario 1 and higher in scenario 2. Since there is no coordination between wind and NG units, the GENCO uses the wind unit to supply BC and uses BC to hedge its expected payoff when the NG unit generation is offered to the day-ahead market. The available energy is 420 MW h in scenario 1 and 360 MW h in scenario 2. Since BC is 400 MW h, the excess 20 MW h in scenario 1 is offered to the day-ahead market, while a penalty is paid in scenario 2 for the 40 MW h deficiency. The expected payoff in Case 2 drops to \$6800 due to the penalty payment, while the downside risk is lowered to \$450 when BC is utilized so that the GENCO is not exposed to market volatilities in scenario 2.

4.1.3. Case 3

The NG and wind units are coordinated in Table 3. Here the NG unit provides a means of satisfying the BC energy when the availability of wind generation is uncertain. The expected payoff increases to \$7090 and the downside risk is decreased to \$260. The inexpensive wind unit is scheduled in both scenarios as in previous Cases. In Scenario 1, the NG unit is fully dispatched and offered to the day-ahead market since its generation cost is cheaper than the market price. In Scenario 2, the NG unit with a minimum capacity of 55 MW is committed at hour 1 to supply the deficient BC of 40 MW h, and its excess 15 MW h is offered to the day-ahead market.

4.1.4. Case 4

The potential BC energy is varied between 200 and 600 MW h and the optimal BC is calculated at 525 MW h. The expected payoff is \$7132.5 while the downside risk is increased slightly to \$292.5. The hourly unit schedules are given in Table 4. The NG unit is committed at all hours in coordination with the wind unit to satisfy BC and offer the excess energy to the day-ahead market. The NG unit is only profitable in Scenario 1. However, the additional energy required by BC would require the commitment of NG unit at hours 2 and 3 with a higher expected payoff than that in Case 3. A higher BC limit would increase the GENCO's expected payoff.

4.1.5. Discussions

The expected payoffs and risks are summarized in Table 5. The available wind energy is utilized in all 4 Cases. The NG unit is not scheduled in Cases 1 and 2 since it is not profitable. The NG unit is coordinated with the wind unit in Scenario 2 of Case 3 to prevent

penalty payments. The NG unit is committed at all hours in Case 4 for supplying the additional BC. The expected payoff is the highest in Case 4 for introducing a higher BC. The downside risk is increased in Case 4 since the GENCO makes a lower payoff in Scenario 2 to boost the payoff in Scenario 1 and increase the expected payoff. The risk could be reduced in Case 4 by introducing additional risk constraints. The wind-NG coordination and the corresponding BC optimization increase the expected payoff and decrease the expected risk by preventing the GENCO from exposure to volatile day-ahead market prices.

4.2. One-year example

A GENCO with 8 NG, 4 cascaded hydro and 3 wind units is analyzed to demonstrate the results. The units are hourly scheduled for the whole one-year period using the proposed algorithm. The forecast errors of day-ahead market prices, natural water inflows, and wind speed are considered. It is assumed that there are no transmission constraints and all units are subject to uniform hourly market prices. The NG infrastructure is shown in Fig. 3. The NG units fed by Pipeline 1 are located in two zones. The yearly NG supply from Zone 1 is limited to 37,200 MMCF. NG contracts are shown in Table 6. The yearly constraint for Pipeline 1 is 155,000 MMCF. The detailed generating unit data, and market prices for energy and ancillary services are given in <http://motor-ece.iit.edu/data/WindBCPBUC>. The Monte Carlo method is used to initially generate 100 scenarios, which are reduced to 12 final scenarios since the objective function does not change much based on this number of scenarios [15]. A 2% of the nominal power of wind unit (i.e., 4 MW) is used in scenarios as the standard deviation of wind forecast error. The study cases are listed in Table 7.

In Cases 2 and 3, the weekly BC energy is fixed at 50,750 MW h. In Case 4, BC energy is varied between 28,000 and 58,500 MW h for calculating the optimal weekly BC. The BC energy price is 46 \$/MW h and the penalty price for deficient energy is 200 \$/MW h. The risk neutral algorithm without the risk constraints is run first for each case. If the financial risk value is greater than zero for a specific case, the risk constrained algorithm is run to reduce the risk.

4.2.1. Case 1

The PBUC algorithm is applied to schedule the GENCO units considering hourly market prices, natural water inflows, and available wind generation. There is no BC and coordination in this case which means that all of the GENCO's units are separately scheduled considering only the hourly energy market price forecasts. When the risk-neutral algorithm is considered, the expected payoff is \$312,025,369 and the downside risk is \$5335,124 with a probability of 0.46. The individual payoff of NG, hydro, and wind units are calculated as \$102,843,689, \$98,896,229 and \$110,285,448, respectively. When the downside risk is considered as constraint, the downside risk is decreased by 3.97% to \$5123,521. The expected payoff would drop by 0.09% to decrease the expected downside risk.

Table 1
Optimal schedule with No BCs and no coordination.

	Hours	$t = 1$	$t = 2$	$t = 3$
Scenario 1	Available Wind Power	100	150	170
	NG unit dispatch	0	0	0
Scenario 2	Available Wind Power	80	130	150
	NG unit dispatch	0	0	0
Expected payoff		\$6900 = 20 * 420 * 50% + 15 * 360 * 50%		

Table 2

Optimal schedule with 400 MW h BC and no coordination.

Hours		$t = 1$	$t = 2$	$t = 3$
Scenario 1	Available Wind Power	100	150	170
	NG unit dispatch	0	0	0
Scenario 2	Available Wind Power	80	130	150
	NG unit dispatch	0	0	0
BC (MW)		400		
Expected payoff		$\$6800 = (400 * 18 + 20 * 20) * 50\% + (400 * 18 - 30 * 40) * 50\%$		

Table 3

Optimal schedule of 400 MW h BC with wind-NG coordination.

Hours		$t = 1$	$t = 2$	$t = 3$
Scenario 1	Available wind power	100	150	170
	NG unit dispatch	200	0	0
Scenario 2	Available wind power	80	130	150
	NG unit dispatch	55	0	0
BC (MW)		400		
Expected payoff		$\$7090 = (400 * 18 + 220 * 20 + 200 * (-19)) * 50\% + (400 * 18 + 15 * 15 - 55 * 19) * 50\%$		

Table 4

Optimal schedule of BC with wind-NG coordination.

Hours		$t = 1$	$t = 2$	$t = 3$
Scenario 1	Available Wind Power	100	150	170
	NG unit dispatch	200	200	200
Scenario 2	Available Wind Power	80	130	150
	NG unit dispatch	55	55	55
BC (MW)		400		
Expected payoff		$\$7132.5 = (525 * 18 + 495 * 20 - 200 * 3 * 19) * 50\% + (525 * 18 - 55 * 3 * 19) * 50\%$		

Table 5

Three hours payoff and risk summary.

Cases	Expected payoff (\$)	Expected risk (\$)
1: No wind-NG coordination and No BC	6900	750
2: No Wind-NG coordination with fixed BC	6800	450
3: Wind-NG coordination with fixed BC	7090	260
4: Wind-NG coordination with optimized BC	7132.5	292.5

Fig. 3. NG infrastructure.

4.2.2. Case 2

The hydro units are considered for supplying the weekly BC in 1 year. The GENCO makes penalty payments at certain weeks when water inflows are lower. This condition leads to a negative payoff of \$69,913,914 for hydro units. The expected payoff drops by 54% to \$143,215,223 in comparison to that in Case 1. The downside risk

Table 6

NG Contracts.

Pipeline #	Contract #	Type	Amount (MMCF)	Cost or price
1	1	Firm	36,000	\$70,200,000
1	2	Interruptible	117,500	\$2170/MMCF

increases to \$168,784,777 that is due to penalty payments. The hydro units are supposed to deliver 2639 GW h of BC energy in 52 weeks. However, due to water shortages the GENCO is subject to penalty payments. When hydro units supply BC, the expected payoff drops as compared to that in Case 1 and scenario payoffs are below the target. The risk constraints are not considered since the expected payoff is well below the target.

4.2.3. Case 3

One NG unit is coordinated with cascaded hydro units for delivering a fixed weekly BC. The expected payoffs for NG and hydro units are calculated as \$106,080,484 and \$98,984,802, while the wind schedule remains unchanged when the risk neutral case is considered. The hydro unit payoff increases by \$168,898,716 when one NG unit is considered additionally to satisfy BC and prevent penalty payments. The added NG would relax the reliance on uncertain water inflows for supplying BC. The total NG units payoff increases by \$3236,795; however, the payoff of individual NG units could decrease based on day-ahead and BC prices as in the 3-h example. The coordination of NG and hydro units would decrease

Table 7
1 Year study cases.

Case	Coordination of units	BC Energy
1	–	None
2	4 Hydro	Fixed
3	4 Hydro + 1 NG	Fixed
4	4 Hydro + 1 NG + 3 Wind	Fixed
5	4 Hydro + 1 NG + 3 Wind	Optimized

the risk by 49.4% to \$2702,192 as compared to that in Case 1 when a risk-neutral algorithm is considered. This case indicates that the BC's constant price and energy would reduce the GENCO's financial risk when NG units with given fuel conditions is added to the BC coordination. The NG unit would supply BCs in the case of water shortages. The risk could be further decreased by considering risk as a constraint in the formulation as will be shown in Table 8.

4.2.4. Case 4

Wind units are further added to the coordination of 4 cascaded hydro and 1 NG unit. The expected payoff increases to \$333,540,888. The payoffs for NG, hydro, and wind units are \$110,038,248, \$102,830,699, and \$120,671,941, respectively. The wind units would increase payoffs by supplying BC and offering energy to the day-ahead market. Hence, the coordination would enhance the GENCO's midterm scheduling and lead to higher payoffs and lower risks.

Fig. 4 shows that the wind forecast error has a crucial impact on a GENCO's financial risk. Here, the target payoff is updated to \$333,000,000 since the coordination has increased the expected payoff in Case 4. In Fig. 4, the financial risk is \$ 2954,180 when wind forecast error is taken zero. In this case, the uncertainty of water inflow and market price is considered. The risk increases as a nonlinear response to the higher uncertainty. The lowest achievable downside risk is \$11,584,835 for a 5% standard deviation. In Fig. 4, if the number of coordinated NG units is increased to 5, the downside risk would be lower. Here, the additional NG units would increase the chance of mitigating financial risks pertaining to wind units. The lowest achievable downside risk is reduced to \$5619,520. Moreover, the NG schedule is analyzed as we increase the wind uncertainty in the 4 Hydro, 1 Wind, and 5 NG case.

Fig. 5 depicts the NG utilization as a function of wind forecast error. The figure shows that there is higher utilization as wind uncertainty increases. It becomes more profitable to schedule the additional NG in order to satisfy BC and maximize the payoff. In addition, NG utilization is lowered for a fixed 1% standard deviation of wind forecast error in order to minimize the risk in the risk-constrained case. However, reduction in NG utilization is less significant as we increase the wind uncertainty, since the

Fig. 4. Financial risks versus wind forecast errors for coordination cases.

additional NG units cannot lower the risk effectively. Consequently, GENCO would have to update its target payoff. A higher level of NG is utilized for 10% uncertainty as compared with the 1% case even though the total delivered energy is lower. This is because the NG units are committed at additional hours in the 10% case but produce less energy resulting in a lower total energy.

4.2.5. Case 5

In addition to the coordination in Case 4, the weekly BC energy is varied here between 28,000 and 58,500 MW h. The expected payoff increases to \$334,308,722. Fig. 6 shows the optimal weekly BC energy in which the BC is higher (lower) in weeks with lower (higher) day-ahead energy price forecasts.

4.2.6. Discussions

The results are summarized in Table 8. In Case 1, the generation is offered only to the day-ahead market with a target payoff of

Fig. 5. Total NG utilization versus wind forecast errors.

Fig. 6. Optimal BC energy.

Table 8
Comparison of cases 1–5 results (Target Payoff is \$312,000,000).

Coordination of units	Risk neutral results (\$)		Risk constrained results (\$)	
	Expected payoff	Downside risk	Expected payoff	Downside risk
1: No Coordination and No BC	312,025,369	5335,124	311,752,084	5123,521
2: 4 Hydro	143,215,223	168,784,777	–	–
3: 4 Hydro + 1 NG	315,350,734	2702,192	315,077,937	2529,455
4: 4 Hydro + 1 NG + 3 Wind	333,540,888	0	333,540,888	0
5: 4 Hydro + 1 NG + 3 Wind, Variable BC	334,308,722	0	334,308,722	0

\$312,000,000. When hydro units are committed to satisfy the BC in Case 2, the expected payoff decreases since water inflow resources are insufficient, and the GENCO is subject to penalty payments if NG and wind unit schedules are the same as those in Case 1. One NG unit is coordinated with cascaded hydro units in Case 3 when the expected payoff is higher than that in Case 1 with a lower financial risk. The coordination will avoid penalty payments and offer energy to the day-ahead market when it is profitable. The wind units are also coordinated in Case 4 which increases the flexibility to satisfy the BC energy and leads to a higher expected payoff and zero downside risk. In Case 5, the weekly BC energy is optimized in one year. Table 8 shows that the BC coordination will reduce risks and increase expected payoffs when compared to Case 1. Notice that all of the GENCO's units are scheduled in each case, the difference between cases is the units considered in BC coordination. These units are given in "Coordination of Units" column of Table 8.

5. Conclusions

A small system demonstration is included to introduce the concept of coordination. Case studies show that BCs could adversely affect the expected payoff and financial risk of the GENCO when only hydro units with uncertain water inflows are considered. The expected payoff increases and the financial risk decreases with the addition of NG and wind units to the coordination. The observations are given as follows:

- Wind forecast uncertainty has a major impact on the midterm operation of power systems. A GENCO should utilize accurate forecasting tools to obtain a sound financial perspective since the financial risk increases nonlinearly with increments in wind power forecast uncertainty.
- Forward BCs could hedge GENCOs' risks when GENCOs are subject to volatile market prices.
- NG units would add flexibility for satisfying BCs in the midterm operation planning.
- A GENCO could utilize the proposed PBUC algorithm in a volatile environment to calculate its highest expected payoff in coordination with BCs.
- NG utilization increases in the risk-neutral case as the wind uncertainty increases. In the risk-constrained case, when the wind uncertainty is lower, the NG utilization is decreased in order to decrease the financial risk. However, a lower NG is not utilized when wind uncertainties are higher. GENCO should determine its target payoff carefully when the wind uncertainty is higher.
- GENCOs can use the proposed algorithm for the midterm planning of generating assets and bidding strategies.

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Comparison of Scenario-Based and Interval Optimization Approaches to Stochastic SCUC

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Abstract—This paper compares applications of scenario-based and interval optimization approaches to stochastic security-constrained unit commitment (Stochastic SCUC). The uncertainty of wind power generation is considered in this study to compare the two approaches, while other types of uncertainty can be addressed similarly. For the simulation of uncertainty, the scenario-based approach considers the Monte Carlo (MC) method, while lower and upper bounds are adopted in the interval optimization. The Stochastic SCUC problem is formulated as a mixed-integer linear programming (MIP) problem and solved using the two approaches. The scenario-based solutions are insensitive to the number of scenarios, but present additional computation burdens. The interval optimization solution requires less computation and automatically generates lower and upper bounds for the operation cost and generation dispatch, but its optimal solution is very sensitive to the uncertainty interval. The numerical results on a six-bus system and the modified IEEE 118-bus system show the attributes of the two approaches for solving the Stochastic SCUC problem. Several convergence acceleration options are also discussed for overcoming the computation obstacles in the scenario-based approach.

Index Terms—Interval optimization, scenario-based approach, stochastic SCUC.

NOMENCLATURE

Variables:

i	Index of thermal units.
I_{it}	Commitment of unit i at time t .
k	Index of curve segments.
P_{ikt}	Dispatch of unit i at time t at segment k .
ΔP_{ikt}^s	Corrective dispatch capability of unit i at time t at segment k in scenario s .
P_{it}	Power dispatch of unit i at time t .
P_{wt}	Power dispatch of wind unit w at time t .

s	Index of scenarios.
$s^{(\cdot)}$	Slack variable.
SU_{it}, SD_{it}	Startup/shutdown cost of unit i at time t .
t	Index of hours.
w	Index of wind generation units.
θ_t^s	Production cost of scenario s at time t .
λ, μ	Dual variables.
$\hat{\cdot}$	Solution to variable.
$(\cdot)^s$	Variable related to scenario s .
$(\cdot)^\pm$	Interval variable.

Constants:

c_{ik}	Incremental cost for segment k of unit i .
N_i	No load cost of unit i .
p^s	Probability of scenario s .
P_{Dt}	System load at time t .
$P_{f,wt}^-$	Interval numbers for the pessimistic wind scenario.
$P_{f,wt}^+$	Interval numbers for the optimistic wind scenario.
P_i^{min}	Minimum capacity of unit i .
P_i^{max}	Maximum capacity of unit i .
P_{ik}^{max}	Power capacity of segment k of unit i .
$P_{f,wt}$	Generation forecast for wind unit w at time t .
R_i^{up}, R_i^{dn}	Up/down limits for corrective dispatch of unit i .

Matrices and Vectors:

$\mathbf{K}_P, \mathbf{K}_D$	Bus-generator/bus-load incidence matrix.
$\mathbf{PL}^{max}$	Vector of upper limit for power flow.
$\mathbf{SF}$	Shift factor matrix.

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I. INTRODUCTION

THE wind generation uncertainty and price-sensitive demand response (DR) introduce new challenges for managing the operational security of electric power systems. Operational data from wind power plants in Denmark [1], Finland [2], and Germany [3] show that the hourly wind energy may often swing by about 20% of its installed capacity within a short span of time. Such fluctuations make it a challenging task to accurately forecast the short-term wind power generation. State-of-the-art forecasting techniques can predict the wind farm aggregated power generation for the next several hours with a forecast error of 5%–20% of the installed capacity [4], [5]. With DR, the price-sensitive load forecasting would require additional price-related inputs. However, price forecast errors of 5%–20% are not uncommon [6]–[8], which will further deteriorate the accuracy of price-sensitive load forecasts.

The modern power systems would have to plan for alternate backup generation in case the day-ahead wind power generation forecast does not materialize or the real-time consumption deviates a lot from the DR-based load forecasts. When the wind power penetration reaches a critical level, the dependency of power systems to wind power generation could inevitably result in additional supply risks associated with the variability of wind speed. Furthermore, when DR reaches a critical market level, the inaccuracy of price-sensitive load forecast could inevitably pose real-time electricity balance risks.

The impact of uncertainty on the operational security of power systems is of fundamental importance when multiple uncertain factors are integrated into power systems. The operational security of power systems can be addressed via Stochastic SCUC. In this paper, the uncertainty of wind power generation is considered in Stochastic SCUC and two distinct solution approaches are compared for maintaining the operational security of power systems.

The first one is the scenario-based approach, in which multiple scenarios are generated to simulate the possible realization of uncertainties. With presumed probability distribution functions, scenarios are generated by the sampling method or the direct discretization of uncertain parameters. Reference [9] presented an effective AC corrective/preventive contingency dispatch for the SCUC model to minimize the system operation cost while maintaining the system security. Reference [10] explored a decentralized solution to the security-constrained optimal power flow problem for large interconnected multi-area power systems. Reference [11] proposed an analytically-sufficient condition for system demand and network parameters to manage security constraints in SCUC. Reference [12] used the N-K contingency criterion to study the impact of random generator outages on power system security. With the assumption that the load forecast uncertainty follows a normal distribution, [13] discretized the normal distribution into intervals and used mid-points as well as probabilities of individual intervals to represent load point uncertainties. References [14]–[16] studied the impact of random generator outages and load forecast errors on unit commitment (UC) via sample scenario trees. References [17] and [18] studied the impact of the high penetration wind power generation on UC, in which the wind forecast uncertainty

was simulated via scenarios sampled from certain probability distributions.

A key issue in the scenario-based approach is to generate scenarios that would truly reflect the probabilistic characteristics of system uncertainties. Scenario-generation methods include MC sampling, moment matching principles, and methods motivated by stability analysis. A general survey of scenario tree algorithms is provided in [19]. The scenario-based approach acknowledges a given probability distribution for simulating uncertainties. A large number of scenarios are usually generated in order to achieve an acceptable solution accuracy, which could increase the scale and the computation burden significantly.

The second approach to Stochastic SCUC is the interval optimization. Instead of sampling scenarios, the interval optimization uses confidence intervals in terms of upper and lower bounds to represent the uncertainty spectrum, and derives optimistic and pessimistic solutions for satisfying the system security requirements. The interval optimization does not require a presumed probability distribution for uncertainties, since interval numbers are acceptable for uncertain inputs [20]–[22]. Reference [23] used the interval optimization to study the impact of bus load uncertainty on system security. The solution was obtained by transforming the problem into two extreme deterministic subproblems corresponding to upper and lower bounds of desired objective function values. Decision alternatives were derived by adjusting decision variables within their solution intervals. Although explicit probability distributions are not required in the interval optimization, the uncertainty intervals would need to be carefully selected. A narrow confidence interval may not cover the entire uncertainty spectrum and, in turn, lead to a UC solution that would not correspond to all possible uncertain situations. On the other hand, a wide interval could lead to pessimistic solutions which would not utilize system resources efficiently and be of limited use to system operators.

The chance-constrained UC was used in [24] to study the load uncertainty by specifying a probability at which stochastic constraints would hold. Usually, such chance constraints are non-convex and generally intractable. The solution to the chance-constrained UC problem could be obtained by sampling scenarios to approximate the true distribution of random variables, or converting it to a sequence of deterministic UC problems which converge to the solution of the chance-constrained UC. The problem scale and the computation burden of the two options would be comparable to those of scenario-based and interval optimization approaches, respectively.

An efficient solution of Stochastic SCUC problem may often lack a rigorous representation of uncertainty when considering complex operating details of generating units and large-scale transmission networks. In this paper, the Stochastic SCUC problem is studied and the wind power generation uncertainty is considered by applying scenario-based and interval optimization approaches. The scenario-based approach generates multiple scenarios by the MC method to simulate the wind power generation uncertainty. In addition to the base case operation cost, the scenario-based approach minimizes expected costs of corrective actions. The interval optimization uses interval numbers, in terms of lower and upper bounds, to

represent the wind power generation uncertainty. The major contribution of this paper is to compare the two approaches to the solution of Stochastic SCUC to address the power system security.

The rest of the paper is organized as follows. Sections II and III present the scenario-based and interval optimization approaches. Section IV applies a six-bus system and the modified IEEE 118-bus system to compare the two approaches. Several convergence acceleration options are discussed in Section V, and the conclusion is drawn in Section VI.

II. SCENARIO-BASED STOCHASTIC SCUC

A. Scenario-Based Stochastic SCUC Formulation

A large number of scenarios are generated to simulate wind speed uncertainty, which would follow the Weibull probability distribution function with the autocorrelation factor and diurnal pattern [25]. The hourly wind energy is procured according to the power curve of wind turbines and hourly wind speed. Other statistical distributions can be similarly considered. The low-discrepancy Latin Hypercube Sampling (LHS) technique is adopted for decreasing the variance of simple MC simulation. Each scenario is assigned a probability that is one divided by the number of scenarios. The scenario reduction technique is adopted to aggregate close scenarios by measuring the distance between scenarios based on the probability metrics and eliminate scenarios with very low probabilities for reducing the scale of the stochastic model and the computation effort [26], [27]. Other scenario reduction techniques may also be adopted including measuring the impact of each scenario on the objective by pre-solving single scenario problems [28], the target/moment matching which matches specified statistical properties [29], and the worst-case scenario probability study which assigns different sets of probabilities by experts and considers the worse scenario [30].

The objective (1) is to minimize the cost of supplying the hourly load in the base case (which includes the no-load cost, startup cost, shutdown cost, and the energy production cost) plus the expected corrective dispatch cost of scenarios, while satisfying various system and unit constraints. The sum of probabilities for all scenarios is equal to one. That is, $\sum_s p^s = 1$. Startup and shutdown costs are considered as time varying variables, which are functions of the number of hours a generating unit has been off and on, respectively [36]. In this paper, only non-quick start generating units are considered in order to facilitate the comparison of the two optimization approaches. That is, in each time interval of the base case and in all scenarios, each generating unit would have the same UC decisions. The formulation for quick-start units can also be included in the formulation [35]. By defining P_{ikt}^s as the power generation of unit i at time t , segment k , and scenario s , which satisfies $P_{ikt}^s = P_{ikt} + \Delta P_{ikt}^s$, (1) is equivalently converted to (2):

$$\begin{aligned} \text{Min} \quad & \sum_t \sum_i \left[N_i \cdot I_{it} + SU_{it} + SD_{it} + \sum_k c_{ik} \cdot P_{ikt} \right] \\ & + \sum_s p^s \cdot \sum_t \sum_i \left[\sum_k c_{ik} \cdot \Delta P_{ikt}^s \right] \end{aligned} \quad (1)$$

$$\begin{aligned} \text{Min} \quad & \sum_t \sum_i [N_i \cdot I_{it} + SU_{it} + SD_{it}] \\ & + \sum_s p^s \cdot \sum_t \sum_i \left[\sum_k c_{ik} \cdot P_{ikt}^s \right] \end{aligned} \quad (2)$$

subject to the following constraints.

Constraints for the Base Case: Base case constraints include the system load balance (3). In addition, system reserve requirements are implicitly represented by deviations in the dispatch solutions of the base case and scenarios, and will be optimally determined via preventive and corrective actions. Generating unit constraints include capacity limits of thermal units (4) and power generation limits of wind power generation units (5):

$$\sum_i P_{it} + \sum_w P_{wt} = P_{Dt} \quad (3)$$

$$\begin{aligned} P_i^{\min} \cdot I_{it} &\leq P_{it} \leq P_i^{\max} \cdot I_{it} \\ P_{it} &= \sum_k P_{ikt} \quad 0 \leq P_{ikt} \leq P_{ik}^{\max} \cdot I_{it} \end{aligned} \quad (4)$$

$$0 \leq P_{wt} \leq P_{f,wt}. \quad (5)$$

Other unit constraints include minimum on/off time, ramping up/down rate, reserve capacity, and fuel and/or emission limitations [31], [32]. Other types of units, such as combined-cycle gas turbine, cascaded hydro, and pumped-storage units, can also be considered. Transmission network constraints include branch flow limits (6), which is enforced in the base case to guarantee the network security of power systems operation:

$$-\text{PL}^{\max} \leq \text{SF} \cdot (\mathbf{K_P} \cdot \mathbf{P_t} - \mathbf{K_D} \cdot \mathbf{P_{Dt}}) \leq \text{PL}^{\max}. \quad (6)$$

Constraints for Each Scenario: Constraints for each scenario include the system load balance (7), generation limits of thermal and wind power units (8), and dispatch adjustment capabilities of generating units (9), which are restricted by the dispatch in the base case by ramping up/down rate limits. Transmission network constraints (10) are enforced in each scenario to guarantee the network security:

$$\sum_i P_{it}^s + \sum_w P_{wt}^s = P_{Dt} \quad (7)$$

$$\begin{aligned} P_i^{\min} \cdot I_{it} &\leq P_{it}^s \leq P_i^{\max} \cdot I_{it} \\ P_{it}^s &= \sum_k P_{ikt}^s \quad 0 \leq P_{ikt}^s \leq P_{ik}^{\max} \cdot I_{it} \\ P_{wt}^s &\leq P_{f,wt}^s \end{aligned} \quad (8)$$

$$\begin{aligned} P_{it}^s - P_{it} &\leq R_i^{\text{up}} \cdot I_{it} \\ P_{it} - P_{it}^s &\leq R_i^{\text{dn}} \cdot I_{it} \end{aligned} \quad (9)$$

$$-\text{PL}^{\max} \leq \text{SF} \cdot (\mathbf{K_P} \cdot \mathbf{P_t^s} - \mathbf{K_D} \cdot \mathbf{P_{Dt}}) \leq \text{PL}^{\max}. \quad (10)$$

Other unit constraints include minimum on/off time, ramping up/down rate, reserve capacity, and fuel and/or emission limitations. The detailed formulation is not included in the paper, which can be obtained in the authors' previous work [31], [32]. However, ramping limits between two successive time intervals in each scenario is not considered because it is assumed that the scenarios at successive time intervals are independent. That is, the scenario s at hour t is not necessarily a consequence of

the scenario s at hour $(t - 1)$. In addition, the proposed Stochastic SCUC is an hourly based model; thus, it is reasonable to assume that there is enough time to adjust the system back to the base case operation status at hour t . Thus, ramping constraints are used to guarantee the secure and economic transfer of system operation status between two successive time intervals in the base, and from the base case to all scenarios at each hour, but not between two successive time intervals in each scenario. In the proposed decomposition framework, the ramping constraints between two successive time intervals in the base is considered in the master UC problem (11), and the ramping constraints between the base case and each hourly scenario is considered in the hourly scenario feasibility and optimality check subproblems (14) and (16).

B. Solution Methodology

The scenario-based Stochastic SCUC model in (2)–(10) is a large-scale, non-convex, non-deterministic polynomial-time hard (NP-hard) problem. The corresponding solution for large-scale systems would be an intractable task without decomposition. The Benders decomposition (BD) is adopted to decompose the Stochastic SCUC problem into one master problem and several tractable subproblems for each scenario.

1) *Master Unit Commitment Problem:* The master UC problem (11) is to minimize the operation cost of the base case with respect to constraints (3)–(5) and other unit constraints mentioned above:

$$\text{Min} \quad \sum_t \sum_i [N_i \cdot I_{it} + SU_{it} + SD_{it}] + \sum_s p^s \cdot \sum_t \theta_t^s. \quad (11)$$

2) *Hourly Network Evaluation for the Base Case:* The hourly network evaluation subproblem (12) checks possible network violations of the master UC solution for the base case. If the objective value $\hat{s}_t$ of (12) is larger than the predefined threshold, a feasibility cut (13) will be utilized:

$$\begin{aligned} \text{Min } s_t \\ \text{s.t. } -1 \cdot s_t \leq \text{PL}^{\max} - \text{SF} \cdot (\mathbf{K_P} \cdot \hat{\mathbf{P}}_t - \mathbf{K_D} \cdot \mathbf{P_{Dt}}) \quad \lambda_{1,t} \\ -1 \cdot s_t \leq \text{PL}^{\max} + \text{SF} \cdot (\mathbf{K_P} \cdot \hat{\mathbf{P}}_t - \mathbf{K_D} \cdot \mathbf{P_{Dt}}) \quad \lambda_{2,t} \\ 0 \leq s_t \end{aligned} \quad (12)$$

$$-(\lambda_{1,t} - \lambda_{2,t})^T \cdot \mathbf{K_P} \cdot (\mathbf{P}_t - \hat{\mathbf{P}}_t) + \hat{s}_t \leq 0. \quad (13)$$

3) *Hourly Feasibility Check for Each Scenario:* The hourly feasibility check subproblem (14) checks possible violations of the master UC solution in each scenario. If the objective value $\hat{S}_t^s$ in (14) is larger than the predefined threshold, a feasibility cut (15) will be utilized:

$$\begin{aligned} \text{Min } S_t^s = s_t^s + s_{1t}^s + s_{2t}^s \\ \text{s.t. } \text{SF} \cdot (\mathbf{K_P} \cdot \mathbf{P}_t^s - \mathbf{K_D} \cdot \mathbf{P_{Dt}}) - 1 \cdot s_t^s \leq \text{PL}^{\max} \\ - \text{SF} \cdot (\mathbf{K_P} \cdot \mathbf{P}_t^s - \mathbf{K_D} \cdot \mathbf{P_{Dt}}) - 1 \cdot s_t^s \leq \text{PL}^{\max} \\ \sum_i P_{it}^s + \sum_w P_{wt}^s + s_{1t}^s - s_{2t}^s = P_{Dt} \\ P_{it}^s \leq R_i^{\text{up}} \cdot \hat{I}_{it} + \hat{P}_{it} \quad \lambda_{1,it}^s \\ -P_{it}^s \leq R_i^{\text{dn}} \cdot \hat{I}_{it} - \hat{P}_{it} \quad \lambda_{2,it}^s \\ P_{it}^s \leq P_i^{\max} \cdot \hat{I}_{it} \quad \mu_{1,it}^s \end{aligned}$$

Fig. 1. Scenario-based approach.

$$\begin{aligned} -P_{it}^s &\leq -P_i^{\min} \cdot \hat{I}_{it} \quad \mu_{2,it}^s \\ P_{wt}^s &\leq P_{f,wt}^s \\ 0 &\leq s_t^s, s_{1t}^s, s_{2t}^s \\ \sum_i &\left[(\hat{\lambda}_{1,it}^s - \hat{\lambda}_{2,it}^s) \cdot (P_{it} - \hat{P}_{it}) \right. \\ &\quad \left. + (\hat{\lambda}_{1,it}^s \cdot R_i^{\text{up}} + \hat{\lambda}_{2,it}^s \cdot R_i^{\text{dn}} + \hat{\mu}_{1,it}^s \cdot P_i^{\max} \right. \\ &\quad \left. - \hat{\mu}_{2,it}^s \cdot P_i^{\min}) \cdot (I_{it} - \hat{I}_{it}) \right] + \hat{S}_t^s \leq 0. \end{aligned} \quad (14)$$

4) *Optimality Check for Each Scenario:* The optimality check subproblem (16) checks the optimality of master UC solution in each scenario. If the objective value $\hat{W}_t^s$ in (16) is larger than the corrective dispatch cost $\hat{\theta}_t^s$ obtained from the master problem, the optimality cut (17) will be utilized:

$$\begin{aligned} \text{Min } W_t^s = \sum_i \left[\sum_k c_{ik} \cdot P_{ikt}^s \right] \\ \text{s.t. } -\text{PL}^{\max} \leq \text{SF} \cdot (\mathbf{K_P} \cdot \hat{\mathbf{P}}_t - \mathbf{K_D} \cdot \mathbf{P_{Dt}}) \leq \text{PL}^{\max} \\ P_{it}^s \leq R_i^{\text{up}} \cdot \hat{I}_{it} + \hat{P}_{it} \quad \lambda_{1,it}^s \\ -P_{it}^s \leq R_i^{\text{dn}} \cdot \hat{I}_{it} - \hat{P}_{it} \quad \lambda_{2,it}^s \\ P_{it}^s \leq P_i^{\max} \cdot \hat{I}_{it} \quad \mu_{1,it}^s \\ -P_{it}^s \leq -P_i^{\min} \cdot \hat{I}_{it} \quad \mu_{2,it}^s \\ P_{it}^s - \sum_k P_{ikt}^s = 0 \\ P_{wt}^s \leq P_{f,wt}^s \\ \theta_t^s \geq \hat{W}_t^s + \sum_i \left[(\hat{\lambda}_{1,it}^s \cdot R_i^{\text{up}} + \hat{\lambda}_{2,it}^s \cdot R_i^{\text{dn}} \right. \\ \quad \left. + \hat{\mu}_{1,it}^s \cdot P_i^{\max} - \hat{\mu}_{2,it}^s \cdot P_i^{\min}) \cdot (I_{it} - \hat{I}_{it}) \right. \\ \quad \left. + (\hat{\lambda}_{1,it}^s - \hat{\lambda}_{2,it}^s) \cdot (P_{it} - \hat{P}_{it}) \right]. \end{aligned} \quad (16)$$

Fig. 1 shows the flowchart of the scenario-based Stochastic SCUC solution. The master UC problem (11) is solved first. The hourly UC and dispatch solutions are then passed on to the hourly network evaluation subproblems (12). The subproblems will examine the feasibility of the master solution. If a subproblem is infeasible which violates the remaining constraints, a corresponding feasibility cut (13) will be generated and added to the next calculation of master problem. The hourly UC and dispatch solutions are also passed on to the hourly security evaluation subproblem (14) and the optimality evaluation subproblem (16) in each scenario. If a scenario subproblem is infeasible, a corresponding feasibility cut (15) will be generated. If the optimal objective $\hat{W}_t^s$ is larger than the corrective dispatch cost

$\hat{\theta}_t^s$, an optimality cut (17) will be generated and added to the next iteration of the master problem. The iterative process will stop when the master solution satisfies feasibility and optimality checks.

III. INTERVAL OPTIMIZATION FOR STOCHASTIC SCUC

The scenario-based approach in Section II holds a presumption that the wind speed uncertainty follows a certain probability distribution. However, the wind speed distribution is often more complex. In addition, a huge number of scenarios are needed in order to achieve an acceptable solution accuracy, which could increase the scale and the computation burden of the stochastic problem. In this section, the interval optimization is adopted as an alternative for the Stochastic SCUC solution with the consideration of wind power generation uncertainty.

The objective of the interval optimization approach is to minimize the cost of supplying the hourly load in the base case (18). Different from the scenario-based approach, the interval optimization approach does not hold any presumptions on probability distributions. The expected corrective dispatch costs are not explicitly included in the objective function. Instead, the impact of uncertainty on operation costs is reflected via the operation cost interval:

$$\text{Min} \quad \sum_t \sum_i \left[\sum_k c_{ik} \cdot P_{ikt} + N_i \cdot I_{it} + SU_{it} + SD_{it} \right]. \quad (18)$$

The base case constraints are (3)–(6) and constraints describing the wind power generation uncertainty are given in (19)–(21) with interval variables $P_{it}^\pm$ and $P_{wt}^\pm$. In (20), the uncertainty interval is derived from a forecasting model [34]. If the forecasting model does not provide such functionality, the uncertainty interval can be formulated using a percentage of the forecast value around such forecast value, i.e., $(1 \pm \alpha)$. The value of α ranges from 0 to 1, for controlling the level of uncertainty under consideration:

$$\sum_i P_{it}^\pm + \sum_w P_{wt}^\pm = P_{Dt} \quad (19)$$

$$\begin{aligned} P_{it} - R_i^{up} \cdot I_{it} &\leq P_{it}^\pm \leq P_{it} + R_i^{up} \cdot I_{it} \\ P_i^{\min} \cdot I_{it} &\leq P_{it}^\pm \leq P_i^{\max} \cdot I_{it} \\ P_{wt}^\pm &\leq [P_{f,wt}^-, P_{f,wt}^+] \end{aligned} \quad (20)$$

$$-\text{PL}^{\max} \leq \text{SF} \cdot (\mathbf{K}_P \cdot \mathbf{P}_t^\pm - \mathbf{K}_D \cdot \mathbf{P}_{Dt}) \leq \text{PL}^{\max}. \quad (21)$$

A. Feasibility Check for the Interval Optimization Subproblem

In (22), the largest violation would occur when the available wind power generation is at its minimum $P_{f,wt}^-$. Thus, by checking the worst case (23), if the objective value S_t^- is larger than the predefined threshold, a feasibility cut (24) will be utilized. Otherwise, if S_t^- is smaller than the predefined threshold, the worst case is feasible. Thus, all other cases will be feasible:

$$\begin{aligned} \text{Min} \quad & s_t^\pm + s_{1t}^\pm + s_{2t}^\pm \\ \text{S.t.} \quad & \text{SF} \cdot (\mathbf{K}_P \cdot \mathbf{P}_t^\pm - \mathbf{K}_D \cdot \mathbf{P}_{Dt}) - 1 \cdot s_t^\pm \leq \text{PL}^{\max} \end{aligned}$$

$$\begin{aligned} & -\text{SF} \cdot (\mathbf{K}_P \cdot \mathbf{P}_t^\pm - \mathbf{K}_D \cdot \mathbf{P}_{Dt}) - 1 \cdot s_t^\pm \leq \text{PL}^{\max} \\ & \sum_i P_{it}^\pm + \sum_w P_{wt}^\pm + s_{1t}^\pm - s_{2t}^\pm = P_{Dt} \\ & \hat{P}_{it} - R_i^{up} \cdot \hat{I}_{it} \leq P_{it}^\pm \leq \hat{P}_{it} + R_i^{up} \cdot \hat{I}_{it} \\ & P_i^{\min} \cdot \hat{I}_{it} \leq P_{it}^\pm \leq P_i^{\max} \cdot \hat{I}_{it} \\ & P_{wt}^\pm \leq [P_{f,wt}^-, P_{f,wt}^+] \\ & 0 \leq s_t^\pm, s_{1t}^\pm, s_{2t}^\pm. \end{aligned} \quad (22)$$

B. Confidence Intervals

The interval optimization derives the power generation confidence interval $[\hat{P}_{it}^-, \hat{P}_{it}^+]$ for each unit i at each hour t , and the confidence interval $[\sum_t \sum_i (\sum_k c_{ik} \cdot \hat{P}_{ikt}^- + N_i \cdot \hat{I}_{it} + \hat{S}U_{it} + \hat{S}D_{it}), \sum_t \sum_i (\sum_k c_{ik} \cdot \hat{P}_{ikt}^+ + N_i \cdot \hat{I}_{it} + \hat{S}U_{it} + \hat{S}D_{it})]$ of the total operation cost, in response to wind power generation uncertainty. The unique feature of the interval optimization is that it uses confidence interval numbers to simulate uncertainty, without considering any assumptions on probability distributions, and derives optimistic and pessimistic solutions for satisfying the security and economic requirements of power systems:

$$\begin{aligned} \text{Min} \quad & S_t^- = s_t^- + s_{1t}^- + s_{2t}^- \\ \text{S.t.} \quad & \text{SF} \cdot (\mathbf{K}_P \cdot \mathbf{P}_t^- - \mathbf{K}_D \cdot \mathbf{P}_{Dt}) - 1 \cdot s_t^- \leq \text{PL}^{\max} \\ & -\text{SF} \cdot (\mathbf{K}_P \cdot \mathbf{P}_t^- - \mathbf{K}_D \cdot \mathbf{P}_{Dt}) - 1 \cdot s_t^- \leq \text{PL}^{\max} \\ & \sum_i P_{it}^- + \sum_w P_{wt}^- + s_{1t}^- - s_{2t}^- = P_{Dt} \\ & P_{it}^- \leq R_i^{up} \cdot \hat{I}_{it} + \hat{P}_{it} \quad \lambda_{1,it}^- \\ & -P_{it}^- \leq R_i^{dn} \cdot \hat{I}_{it} - \hat{P}_{it} \quad \lambda_{2,it}^- \\ & P_{it}^- \leq P_i^{\max} \cdot \hat{I}_{it} \quad \mu_{1,it}^- \\ & -P_{it}^- \leq -P_i^{\min} \cdot \hat{I}_{it} \quad \mu_{2,it}^- \\ & P_{wt}^- \leq P_{f,wt}^- \\ & 0 \leq s_t^-, s_{1t}^-, s_{2t}^- \end{aligned} \quad (23)$$

$$\begin{aligned} & \sum_i \left[(\hat{\lambda}_{1,it}^- - \hat{\lambda}_{2,it}^-) \cdot (P_{it} - \hat{P}_{it}) \right. \\ & \quad \left. + (\hat{\lambda}_{1,it}^- \cdot R_i^{up} + \hat{\lambda}_{2,it}^- \cdot R_i^{dn} + \hat{\mu}_{1,it}^- \cdot P_i^{\max} \right. \\ & \quad \left. - \hat{\mu}_{2,it}^- \cdot P_i^{\min}) \cdot (I_{it} - \hat{I}_{it}) \right] + \hat{S}_t^- \leq 0. \end{aligned} \quad (24)$$

IV. CASE STUDIES

A six-bus system and the modified IEEE 118-bus system are used to analyze scenario-based and interval optimization approaches to Stochastic SCUC. The case studies utilize CPLEX 12.1.0 on an Intel Core i7 2.67-GHz personal computer.

A. Six-Bus System

The six-bus system shown in Fig. 2 is used to illustrate the proposed study, which has three regular thermal generators and one wind farm [31]. Corrective dispatch capabilities of the three

Fig. 2. One-line diagram of the six-bus system.

Fig. 3. 24-h load profile and wind power generation forecasts.

thermal units are 9.16 MW, 8.33 MW, and 3.33 MW, respectively. The system load profile and wind power generation forecasts for the 24 h are shown in Fig. 3. The wind power generation is calculated based on wind speed forecasts and wind turbine power curves, where the cut-in, rated, and cut-out wind speeds are 5 m/s, 14 m/s, and 24 m/s, respectively. The total installed wind power generation capacity is 60 MW, which represents 14.63% of the total system generation capacity. Two cases are studied here:

- Case 1) Stochastic SCUC study at hour 1.
- Case 2) The 24-h Stochastic SCUC study.

Case 1: The Stochastic SCUC is studied at hour 1, which is a high wind and low load hour. The wind speed forecast is 9.44 m/s, which corresponds to the wind power generation of 18.39 MW. The system load is 178.76 MW.

First, the interval optimization approach for the Stochastic SCUC problem is studied, in which the wind power generation uncertainty is considered as 20% of its installed capacity, i.e., $60 \times 20\% = 12$ MW. That is, the available wind power generation in the pessimistic case is $(18.39 - 12)$ MW, and $(18.39 + 12)$ MW in the optimistic case. The Stochastic SCUC solution with the interval optimization approach is shown in Table I. The economic operation strategy while satisfying the operational security under both pessimistic and optimistic cases is to switch on the G1 unit only and adopt wind power generation of 15.52 MW, 6.36 MW, and 24.68 MW in the base case, pessimistic case, and optimistic case, respectively. In this case, the corrective dispatch capability of G1 can balance the wind power generation uncertainty and securely transfer the system operation status from the base case to both pessimistic and optimistic cases. The interval optimization method also provides an operation cost interval of [\\$3114.34, \\$3496.68].

Second, the scenario-based approach is used to study the Stochastic SCUC. The wind speed is assumed to follow the Weibull distribution and its uncertainty is simulated via 10 000

TABLE I
INTERVAL OPTIMIZATION RESULTS IN CASE 1

	Cost (\$)	G1 (MW)	G2 (MW)	G3 (MW)	Wind (MW)
Base case	3,305.38	163.24	0	0	15.52
Pessimistic	3,496.68	172.40	0	0	6.36
Optimistic	3,114.34	154.08	0	0	24.68

TABLE II
SCENARIO-BASED RESULTS IN CASE 1 (REDUCED 100 SCENARIOS)

	Cost (\$)	G1 (MW)	G2 (MW)	G3 (MW)	Wind (MW)
Base case	3437.19	169.60	0	0	9.16
Corrective action	-75.12	160.43-178.76	0	0	0-18.33

TABLE III
INTERVAL OPTIMIZATION RESULTS FOR 40% WIND VOLATILITY IN CASE 1

	Cost (\$)	G1 (MW)	G2 (MW)	G3 (MW)	Wind (MW)
Base case	3,437.84	169.60	0	0	9.16
Pessimistic	3,632.93	178.76	0	0	0
Optimistic	3,246.79	160.44	0	0	18.32

scenarios. The scenario reduction is used to reduce the scale and the computation time of the stochastic model. Table II shows the results with the reduced 100 scenarios. The expected operation cost is \$3362.07, which includes the base case cost of \$3437.19 and the expected corrective dispatch cost of \$-75.12.

In the interval optimization approach with 20% wind power generation uncertainty, 6.36 MW wind power generation is available in the pessimistic case. This makes it possible to adopt 15.52 MW wind power generation in the base case, with a corrective dispatch of 9.16 MW provided by G1. In comparison, the scenario-based approach includes scenarios with wind speeds lower than the cut-in value, which derives 0 MW wind power output. In order to securely transfer the system operation status from the base case to scenarios, the base case would dispatch 9.16 MW of wind power generation, which leads to a higher base case cost than that of the interval optimization.

The sensitivity analysis is performed for the two approaches. Table III shows the interval optimization results when the wind power generation uncertainty is assumed to be 40% of the installed wind power generation capacity, i.e., $40\% \times 60 = 24$ MW. In this situation, the pessimistic case will have 0 MW wind power output, which adopts 9.16 MW wind power generation in the base case and derives the same base case result as that of the scenario-based approach in Table II. This study shows that the interval optimization solution is very sensitive to the presumed wind uncertainty interval. Fig. 4 shows the operation cost for all 100 scenarios and the operation cost intervals for the interval optimization approach. All scenario costs fall within the lower and upper bounds derived from the interval optimization, which indicates that when the wind uncertainty interval is properly set, the interval optimization could provide accurate operation cost boundaries to cover possible scenarios in the scenario-based approach.

Table IV shows the expected corrective dispatch costs of different tests in the scenario-based approach. For all tests, the base case UC results are the same as those in Table II. In Table IV, the tests with different number of original scenarios and the

Fig. 4. Scenario operation costs and the operation cost interval.

TABLE IV
EXPECTED CORRECTIVE DISPATCH COSTS IN CASE 1 (\$)

# of original scenarios	# of scenarios after scenario reduction		
	5	10	100
1,000	-70.47	-74.91	-74.92
10,000	-70.78	-75.15	-75.12
10,000 (Another sample)	-70.75	-75.10	-75.12

TABLE V
RESULTS FOR EACH SCENARIO IN CASE 1 (REDUCED FIVE SCENARIOS)

	S1	S2	S3	S4	S5
Probability	0.171	0.211	0.346	0.113	0.159
Available wind power (MW)	0	29.76	59.82	3.44	12.72
Adopted wind power (MW)	0	18.33	18.33	3.44	12.72
Scenario cost (\$)	3,632.93	3,246.79	3,246.79	3,559.20	3,363.75
Corrective cost (\$)	195.43	-190.40	-190.40	122.01	-73.44

same number of reduced scenarios have close expected corrective dispatch costs. In addition, ten appears to be an appropriate number of scenarios since their expected corrective dispatch costs are quite close to those of 100 scenarios; though the cost of five scenarios deviates a lot. Furthermore, the last two rows of Table IV show that the expected corrective dispatch costs of another 10 000 sample test are quite close to those of the first 10 000 scenario sample test, which shows that the expected corrective dispatch costs are stable for different scenario samples. Table IV shows that, in this case, the expected corrective dispatch costs are all negative for different tests. This is because in most scenarios, the amount of wind power generation adopted is higher than that of the base case. Thus, less generation from regular thermal units is needed and the scenario operation cost is lower than that of the base case. Table V shows the test results with reduced five scenarios. In this study, scenarios 2, 3, and 5 would adopt more wind power generation and correspondingly have lower scenario operation costs than the base case. The total probability of scenarios 2, 3, and 5 is $0.211 + 0.346 + 0.159 = 0.716$, which brings out the negative expected corrective dispatch cost of \$-70.47.

Case 2: The 24-h Stochastic SCUC is studied in this case. Tables VI and VII show the 24-h Stochastic SCUC results with the interval optimization and the scenario-based approaches, respectively. Table VI shows that the expected operation costs of test cases, given in Table VII, fall in the operation cost interval of [\$100 048.78, \$109 294.13]. Table VII again shows that ten would be an appropriate number of scenarios in this case since

TABLE VI
INTERVAL OPTIMIZATION RESULTS IN CASE 2

	Base case	Pessimistic	Optimistic
Cost (\$)	105,595.50	109,294.13	100,048.78

TABLE VII
SCENARIO-BASED RESULTS IN CASE 2 (\$)

# of scenarios after reduction	5	10	100
Expected cost for the first run	102,270.05	103,887.93	104,295.86
Expected cost for the second run	102,294.87	103,835.80	104,273.27

Fig. 5. Wind power generation forecasts for the three wind farms.

TABLE VIII
INTERVAL OPTIMIZATION RESULTS FOR 24 H (\$)

Wind Uncertainty	Base case	Pessimistic	Optimistic
15%	2,006,689.78	2,032,250.47	1,968,175.55
25%	2,006,844.22	2,042,033.43	1,944,019.38

TABLE IX
SCENARIO-BASED RESULTS FOR 24 H (\$)

# of scenarios after reduction	5	10	100
Expected cost for the first run	1,969,428.82	1,970,747.87	1,969,768.34
Expected cost for the second run	1,971,080.53	1,970,771.70	1,969,547.27

their costs are close to those of 100 scenarios (i.e., the differences are $(104\,295.86 - 103\,887.93)/104\,295.86 = 0.39\%$ and $(104\,273.27 - 103\,835.80)/104\,273.27 = 0.42\%$). In addition, the expected costs are stable with different replications (i.e., the differences are $(102\,270.05 - 102\,294.87)/102\,270.05 = -0.024\%$, $(103\,887.93 - 103\,835.80)/103\,887.93 = 0.05\%$, and $(104\,295.86 - 104\,273.27)/104\,295.86 = 0.022\%$).

B. IEEE 118-Bus System

The modified IEEE 118-bus system with 54 thermal units, three wind farms, and 186 branches is studied. The peak load is 7200 MW with detailed generator and transmission network data given in [31]. The 24-h wind power generation forecasts for the three geographically dispersed wind farms are shown in Fig. 5.

Table VIII shows operation costs of the base case, the pessimistic case, and the optimistic case for the entire 24 h, when the wind power uncertainty is considered to be 15% and 25% of the total installed wind power generation capacity, respectively. Table IX shows operation costs of test cases with 10 000 original scenarios for the scenario-based approach. In comparison, the scenario-based solutions are more rigid, i.e., the optimal objectives values are approximately the same in test cases. However, the objective intervals in the interval optimization

deviate a lot as the wind power uncertainty interval is changed. When the wind power uncertainty is increased from 15% to 25%, the costs of pessimistic and optimistic cases would change by $(2\,042\,033.43 - 2\,032\,250.74)/2\,032\,250.74 = 0.48\%$ and $(1\,944\,019.38 - 1\,968\,175.55)/1\,968\,175.55 = -1.23\%$ although the base case costs are close. In comparison, changes in the expected operation costs of test cases are within 0.084% in the scenario-based approach.

The interval optimization approach takes five iterations with a computation time of 73 s to reach the optimal solution. For the scenario-based approach, with the reduced ten scenarios, it takes seven iterations with a computation time of 178 s. For reduced 100 scenarios, it needs 20 iterations with the total computation time of 2108 s. Since the Stochastic SCUC is an NP-hard problem, the increase in the number of scenarios will dramatically increase the computation burden. In comparison, the computation time for the interval optimization is equivalent to that of a scenario-based approach with the consideration of only two scenarios.

V. ACCELERATION STRATEGY

The computation burden of the scenario-based approach for the Stochastic SCUC problem may be improved by applying the following options:

- 1) Tighten the master UC problem formulation (11). It is conceivable that the inclusion of system reserve requirement and/or a few scenarios in the first iteration of the master UC problem would result in a better initial UC solution.
- 2) Make use of the specific structure of Stochastic SCUC problem in certain cases for eliminating optimality cuts. An alternative partition strategy enabled by the combination of (11) and (16) as the master problem may eliminate the need for optimality cuts and require fewer iterations, when a combined optimization of the MIP problem (11) and (16) is possible.
- 3) Adopt acceleration strategies proposed for the deterministic SCUC [11], [32]. Reference [11] proposed a necessary and sufficient condition to identify and eliminate inactive security constraints in the SCUC problem, for reducing the problem scale and the computation burden. Reference [32] explored a reasonable operational strategy for fixing and unlocking generating units at each SCUC iteration, to control the iterative SCUC solution efficiently and accelerate the execution.
- 4) Generate multiple strong cuts to accelerate the convergence of the Benders decomposition approach [33]. Multiple strong cuts would restrict the feasible region of the master UC problem at each iteration and, in turn, result in a significant reduction in the number of iterations and the necessary CPU time for computation. Subproblems for generating additional cuts can be executed in parallel, which would not introduce any extra computation time.

VI. CONCLUSIONS

The impact of various uncertainties on the operational security of power systems is becoming more important, as more uncertainty factors are integrated into power systems. This paper evaluates the scenario-based approach and the interval

optimization approach for the Stochastic SCUC solution with the consideration of uncertain wind power generation. A six-bus system and the modified IEEE 118-bus system are studied to evaluate the two approaches. The scenario-based approach provides more stable solutions. However, the scenario-based approach may come with larger problem scales and higher computation burdens. A few convergence acceleration options are referred to in the paper for overcoming the computation obstacles of the scenario-based approach. More research on this issue will be required in the future. The interval optimization approach requires less computation time to generate lower and upper bounds automatically for the objective value. However, its optimal solution is very sensitive to the uncertainty interval. In addition, the interval optimization may not be suitable for simulating discrete uncertain variables such as random outages of generators and transmission lines in power systems.

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Security-Constrained Transmission Switching with Voltage Constraints

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Abstract— Transmission switching (TS) would play a vital role in the security and economics of electric power systems. The application of TS to the AC model of security-constrained unit commitment (SCUC) for the day-ahead scheduling is presented in this paper. The proposed AC model of SCUC with TS would include real and reactive power flow constraints which increase the controllability of base case and contingency solutions with voltage constraints. A general FACTS model is introduced for the reactive power management in SCUC which is based on the power injection model (PIM). A modified Newton-Raphson power flow model is introduced in the proposed SCUC with TS in which line flows are considered as variables. The proposed AC network model is compared with the DC network model for enhancing the power network controllability and minimizing the operation cost. The case studies exhibit the effectiveness of the TS application to SCUC with AC network constraints.

Keywords: Transmission switching, Security-constrained unit commitment, Voltage Constraints, FACTS devices.

NOMENCLATURE

Indices:

b, m, n	Indices for bus
c	Index for contingency
i	Index for generator
l	Index for line
ns	Index for non-switchable line
s	Index for switchable line

Sh	Superscript for shunt power injections
Se	Superscript for series power injections
t	Index for time

Sets:

L_b	Set of lines connected to bus b
U_b	Set of units connected to bus b

Parameters:

M	Large positive constant
NB	Number of buses
NG	Number of units
NNS	Number of non-switchable lines
NS	Number of switchable lines
NT	Number of time periods
$PL_l^{\max}$	Real power flow limit of line l
$Q_i^{\min}, Q_i^{\max}$	Reactive power generation limits of unit i
UX_{it}	Contingency state of unit i at time t
UY_{lt}	Contingency state of line l at time t
$V_b^{\min}, V_b^{\max}$	Voltage magnitude limits of bus b
α_b	Power injection coefficient of FACTS device
δ_{lt}	Standing phase angle difference limit of line l at time t
Λ_{it}	Permissible real power adjustment of unit i at time t

Variables:

I_{it}	Commitment state of unit i at time t
$MP_{bt,1}, MP_{bt,2}$	Slack variables for real power mismatch in bus b at time t
$MQ_{bt,1}, MQ_{bt,2}$	Slack variables for reactive power mismatch in bus b at time t
P_{it}	Real power generation of unit i at time t
PF_{bt}	Real power injection in bus b at time t due to FACTS device

PL_{lt}	Real power flow of line l at time t
Q_{it}	Reactive power generation of unit i at time t
QF_{bt}	Reactive power injection in bus b at time t due to FACTS device
QL_{lt}	Reactive power flow of line l at time t
V_{bt}	Voltage magnitude of bus b at time t
w_t	Total mismatch at time t
z_{lt}	Switching state of line l at time t
θ_{bt}	Voltage angle of bus b at time t
$\psi_{it}, \mu_{lt}, \pi_{it}$	Dual variables

Symbols:

$\wedge$	Given variables
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Matrices and Vectors:

$\mathbf{1}$	Vector of ones
$\mathbf{A}, \mathbf{B}, \mathbf{C}, \mathbf{D}$	Jacobian matrices
$\mathbf{dP}_0$	Real power mismatch vector
$\mathbf{dQ}_0$	Reactive power mismatch vector
$\mathbf{MP}_1, \mathbf{MP}_2$	Vector of slack variables for real power mismatch
$\mathbf{MQ}_1, \mathbf{MQ}_2$	Vector of slack variables for reactive power mismatch
$\mathbf{X}$	Bus-Line incidence matrix
$\mathbf{Y}$	Bus-Unit incidence matrix
$\Delta \mathbf{P}$	Real power generation increment vector
$\Delta \mathbf{PL}$	Real power flow increment vector
$\Delta \mathbf{PL}^{\min}, \Delta \mathbf{PL}^{\max}$	Real power flow lower and upper increment vectors
$\Delta \mathbf{Q}$	Reactive power generation increment vector
$\Delta \mathbf{Q}^{\min}, \Delta \mathbf{Q}^{\max}$	Reactive power generation lower and upper increment vectors
$\Delta \mathbf{QL}$	Reactive power flow increment vector
$\Delta \mathbf{V}$	Bus voltage increment vector

$\Delta V^{\min}, \Delta V^{\max}$	Bus voltage lower and upper increment vectors
$\Delta \theta$	Bus phase angle increment vector
$\Delta \Lambda^{\min}, \Delta \Lambda^{\max}$	Real power generation adjustment lower and upper increment vectors

1. INTRODUCTION

Recent market design proposals consider a more active role for transmission owners. Incentives are provided for transmission owners to increase investments in transmission and to utilize transmission lines more efficiently. Considering that building new transmission lines to meet the growing demand is a difficult and time-consuming task, the more efficient use of the existing transmission network would be a valuable alternative. Transmission switching (TS) is an efficient approach to utilize the power grid more comprehensively. TS will take specific transmission lines temporarily out of service in order to benefit from the modified network topology. This capability will be considered primarily for the newly installed transmission lines in the electricity market. TS has gained further attention since the FERC order 890 has called for an economic utilization of transmission capacity and hence made TS more favorable for economic purposes. The independent system operator (ISO) may apply TS as a corrective action for mitigating transmission flow violations [1]-[4], as a congestion management tool [5], for enhancing the power system security [6]-[9], and improving the system economics while maintain the security constraints [10]. TS would manage topology changes which could affect nodal prices, load payments, generation revenues, congestion costs, and flowgate prices. It can also improve the solution of the capacity expansion planning problem while providing economic benefits [11]-[12].

Much of the previous studies considered the TS for real power flow adjustments. In this paper, the optimal TS is considered for mitigating both transmission flow and bus voltage violations in the security-constrained unit commitment (SCUC) problem. To consider voltage constraints, a modified Newton–Raphson model is utilized which will satisfy the base case and contingency constraints. The proposed SCUC solution uses the Benders decomposition to decompose the model into a master problem and two subproblems [13]-[17]. A general model of FACTS devices is incorporated into the proposed SCUC formulations, which is capable of modeling all types of series, shunt or series-shunt FACTS devices. These features will add a comprehensive perspective to the SCUC formulation for TS applications.

Fig. 1 depicts the flowchart of the proposed SCUC model with AC network constraints. Benders decomposition is utilized to decompose the SCUC problem into smaller and easier to solve subproblems. The master problem uses the available market information to find the optimal hourly schedule of units (UC) by considering the prevailing UC constraints [18]-[20]. The hourly solution of UC is used in the subproblems to examine the AC network constraints. The TS ability of lines is considered and FACTS devices are incorporated in the subproblems if violations are detected. TS binary variables are determined via UC and

consequently, they are considered as constant values in the subproblems. Given the unit and line schedule by the UC solution, the Subproblem 1 will check the base case network feasibility. In this subproblem, slack variables for real and reactive power mismatches are minimized based on line flow and FACTS device adjustments. The proposed Benders cut incorporates slack variables for the real and reactive power mismatch that is mitigated by recalculating the unit and line schedules. A converged base case power flow will be achieved based on the UC results. The Contingencies Network Check subproblem uses the UC solution for the base case to check the system security in case of contingencies. Using AC power flow equations, both real and reactive power mismatches are minimized in this subproblem. It is required to limit the standing phase angle difference to safeguard the rotor shaft. Different approaches are proposed to obtain the minimum generation redispatch in a reasonable time for desired standing phase angles [21]-[26]. This problem which is inevitable in restoration practices may also occur in the normal operation of power systems when attempting to reclose a single line that is a part of a transmission loop [23]. To present a practical TS model, the standing phase angle difference limit of switchable lines is formulated in our proposed model.

FACTS devices are incorporated here in the SCUC model. FACTS devices are traditionally modeled by a voltage (current) source model (VSM). VSM formulates the device according to the operating conditions, thus representing the device intuitively. However, it destroys the symmetric characteristics of the admittance matrix and may cause oscillations in the power flow solution in successive iterations. A more common approach, as used in this paper, is to utilize power injection model (PIM). The PIM is derived from VSM, in which real and reactive power injections are considered as independent control variables, as shown in Fig. 2. Using PIM, the symmetric characteristics of admittance matrix is kept and the oscillations in the power flow solution are mitigated. Due to advantages of the PIM, this model were extended to almost all FACTS devices and used in most of the researches on operation and control of power systems with FACTS devices. Table 1 represents the required PIM components for modeling different FACTS devices. The power injections are only interim results, where they would be converted to the corresponding VSM parameters once the solution is obtained. The control parameters and the required conversion to obtain control parameters from PIM components are not listed in the table since it can be found in the literature.

The rest of the paper is organized as follows. Section 2 presents the formulation of the problem. Section 3 conducts the numerical simulations and in detail discusses results obtained for the IEEE 118-bus system. Finally, concluding remarks are drawn in Section 4.

2. SECURITY-CONSTRAINED REACTIVE POWER FORMULATION

The step by step procedure for the solution of the proposed SCUC model is given as follows.

2.1. UC (Optimal Hourly Schedule of Units)

The UC solution provides the hourly generation dispatch and the state of switchable lines in both base case and contingencies. At the first iteration of the problem, there is no constraint on switchable lines states. So, random initial values might be assigned to these variables. However, in our approach we consider that all lines are in service at the first iteration. In subsequent iterations, the Benders cuts from the subproblems establish more constraints on switchable lines states. Although the switchable lines states are determined in the master problem, they are actually governed by Benders cuts stemmed out of the subproblems. Mixed-integer programming (MIP) is used to formulate the UC problem.

2.2. Network Check (General Formulation)

In the Base Case and Contingencies Network Check subproblems, a linearized AC power flow based on Newton-Raphson method is performed to check the existence of a converged solution. The general formulation of this linearized power flow in matrix form is expressed by (1)-(8).

$$\text{Min } w(\hat{\mathbf{I}}, \hat{\mathbf{P}}) = \mathbf{1}^T (\mathbf{MP}_1 + \mathbf{MP}_2) + \mathbf{1}^T (\mathbf{MQ}_1 + \mathbf{MQ}_2) \quad (1)$$

$$\begin{bmatrix} \mathbf{Y} * \Delta \mathbf{P} \\ \mathbf{Y} * \Delta \mathbf{Q} \end{bmatrix} - \begin{bmatrix} \mathbf{X} * \Delta \mathbf{PL} \\ \mathbf{X} * \Delta \mathbf{QL} \end{bmatrix} + \begin{bmatrix} \mathbf{MP}_1 \\ \mathbf{MQ}_1 \end{bmatrix} - \begin{bmatrix} \mathbf{MP}_2 \\ \mathbf{MQ}_2 \end{bmatrix} = \begin{bmatrix} \mathbf{dP}_0 \\ \mathbf{dQ}_0 \end{bmatrix} \quad (2)$$

$$\begin{bmatrix} \Delta \mathbf{PL} \\ \Delta \mathbf{QL} \end{bmatrix} = \begin{bmatrix} \mathbf{A} & \mathbf{B} \\ \mathbf{C} & \mathbf{D} \end{bmatrix} \begin{bmatrix} \Delta \mathbf{V} \\ \Delta \mathbf{P} \end{bmatrix} \quad (3)$$

$$\Delta \mathbf{Q}^{\min} \leq \Delta \mathbf{Q} \leq \Delta \mathbf{Q}^{\max} \quad (4)$$

$$\Delta \mathbf{PL}^{\min} \leq \Delta \mathbf{PL} \leq \Delta \mathbf{PL}^{\max} \quad (5)$$

$$\Delta \mathbf{V}^{\min} \leq \Delta \mathbf{V} \leq \Delta \mathbf{V}^{\max} \quad (6)$$

$$\Delta \mathbf{P} = \mathbf{0} \quad (7)$$

$$\Delta \mathbf{A}^{\min} \leq \Delta \mathbf{P} \leq \Delta \mathbf{A}^{\max} \quad (8)$$

The AC power flow will converge when real and reactive power mismatches at each bus are zero. The objective function (1) minimizes the slack variables for real and reactive power mismatches in the system (2). In this formulation, instead of using the common form of Jacobian matrix [27], the line real and reactive power flows are incorporated in the power balance equation. The line flows are linked to power injections/withdrawals at the associated buses. The line flows are calculated based on bus voltage magnitudes and angles as presented by (3). This modification does not change the basic power flow formulation while it enables the modeling of network topology adjustments. Parallel lines are modeled efficiently since the real and reactive power flows of each line are considered as problem variables. Limits on reactive power generation, line real power flow and bus voltage

magnitudes are presented by (4)-(6), respectively. In the Base Case Network Check, the limit on real power generation (7) is applied to all units except that of slack bus to compensate for power loss mismatch. In the Contingencies Network Check, (8) is applied to consider the unit real power generation adjustments in contingencies. Using the proposed AC power flow equations, the network topology adjustments, i.e. transmission line switching and contingency, can simply be applied by modifying (3). Using the proposed formulation, the power injections due to FACTS devices are added to (2) and unit contingencies are considered by modifying (4) and (8). Further details on the proposed MIP formulation are provided in the following subsection.

2.3. Network Check (Detailed Formulation)

Once the initial unit and line schedule is determined by the UC problem, the Base Case Network Check subproblem is solved for 24 hours. In this subproblem, slack variables for real and reactive power mismatches at various buses are considered for minimization to check whether a converged AC power flow solution can be obtained based on UC results.

$$\text{Min } w_t^c = \sum_{b=1}^{NB} (MP_{bt,1}^c + MP_{bt,2}^c) + \sum_{b=1}^{NB} (MQ_{bt,1}^c + MQ_{bt,2}^c) \quad (9)$$

The constraints are given as follows.

$$z_{lt}^c = \hat{z}_{lt}^c \quad \leftrightarrow \quad \mu_{lt}^c \quad (l = 1, \dots, NS) \quad (10)$$

$$\sum_{i \in U_b} \Delta P_{it}^c - \sum_{l \in L_b^s} \Delta PL_{lt}^{sc} - \sum_{l \in L_b^{ns}} \Delta PL_{lt}^{nsc} + MP_{bt,1}^c - MP_{bt,2}^c = dP_{0bt}^c \quad (b = 1, \dots, NB) \quad (11)$$

$$\sum_{i \in U_b} \Delta Q_{it}^c - \sum_{l \in L_b^s} \Delta QL_{lt}^{sc} - \sum_{l \in L_b^{ns}} \Delta QL_{lt}^{nsc} + MQ_{bt,1}^c - MQ_{bt,2}^c = dQ_{0bt}^c \quad (b = 1, \dots, NB) \quad (12)$$

$$\Delta Q_{it}^{c \min} \hat{I}_{it} \leq \Delta Q_{it}^c \leq \Delta Q_{it}^{c \max} \hat{I}_{it} \quad \leftrightarrow \quad \psi_{-it}^c, \psi_{it}^c \quad (i = 1, \dots, NG) \quad (13)$$

$$\Delta V_{bt}^{c \min} \leq \Delta V_{bt}^c \leq \Delta V_{bt}^{c \max} \quad (b = 1, \dots, NB) \quad (14)$$

$$\Delta PL_{lt}^{nsc} - \sum_{b=1}^{NB} \frac{\partial PL_{lt}^{nsc}}{\partial \theta_{bt}^c} \Delta \theta_{bt}^c - \sum_{b=1}^{NB} \frac{\partial PL_{lt}^{nsc}}{\partial V_{bt}^c} \Delta V_{bt}^c \leq M (1 - UY_{lt}^c) \quad (l = 1, \dots, NNS) \quad (15)$$

$$\Delta PL_{lt}^{nsc} - \sum_{b=1}^{NB} \frac{\partial PL_{lt}^{nsc}}{\partial \theta_{bt}^c} \Delta \theta_{bt}^c - \sum_{b=1}^{NB} \frac{\partial PL_{lt}^{nsc}}{\partial V_{bt}^c} \Delta V_{bt}^c \geq -M (1 - UY_{lt}^c) \quad (l = 1, \dots, NNS) \quad (16)$$

$$-\Delta PL_{lt}^{c \max} UY_{lt}^c \leq \Delta PL_{lt}^{nsc} \leq \Delta PL_{lt}^{c \max} UY_{lt}^c \quad (l = 1, \dots, NNS) \quad (17)$$

$$\Delta QL_{lt}^{nsc} - \sum_{b=1}^{NB} \frac{\partial QL_{lt}^{nsc}}{\partial \theta_{bt}^c} \Delta \theta_{bt}^c - \sum_{b=1}^{NB} \frac{\partial QL_{lt}^{nsc}}{\partial V_{bt}^c} \Delta V_{bt}^c \leq M (1 - UY_{lt}^c) \quad (l = 1, \dots, NNS) \quad (18)$$

$$\Delta QL_{lt}^{nsc} - \sum_{b=1}^{NB} \frac{\partial QL_{lt}^{nsc}}{\partial \theta_{bt}^c} \Delta \theta_{bt}^c - \sum_{b=1}^{NB} \frac{\partial QL_{lt}^{nsc}}{\partial V_{bt}^c} \Delta V_{bt}^c \geq -M (1 - UY_{lt}^c) \quad (l = 1, \dots, NNS) \quad (19)$$

$$\Delta PL_{lt}^{sc} - \sum_{b=1}^{NB} \frac{\partial PL_{lt}^{sc}}{\partial \theta_{bt}^c} \Delta \theta_{bt}^c - \sum_{b=1}^{NB} \frac{\partial PL_{lt}^{sc}}{\partial V_{bt}^c} \Delta V_{bt}^c \leq M (2 - z_{lt}^c - UY_{lt}^c) \quad (l = 1, \dots, NS) \quad (20)$$

$$\Delta PL_{lt}^{sc} - \sum_{b=1}^{NB} \frac{\partial PL_{lt}^{sc}}{\partial \theta_{bt}^c} \Delta \theta_{bt}^c - \sum_{b=1}^{NB} \frac{\partial PL_{lt}^{sc}}{\partial V_{bt}^c} \Delta V_{bt}^c \geq -M (2 - z_{lt}^c - UY_{lt}^c) \quad (l = 1, \dots, NS) \quad (21)$$

$$-\Delta PL_{lt}^{c \max} z_{lt}^c UY_{lt}^c \leq \Delta PL_{lt}^{sc} \leq \Delta PL_{lt}^{c \max} z_{lt}^c UY_{lt}^c \quad (l = 1, \dots, NS) \quad (22)$$

$$\Delta QL_{lt}^{sc} - \sum_{b=1}^{NB} \frac{\partial QL_{lt}^{sc}}{\partial \theta_{bt}^c} \Delta \theta_{bt}^c - \sum_{b=1}^{NB} \frac{\partial QL_{lt}^{sc}}{\partial V_{bt}^c} \Delta V_{bt}^c \leq M (2 - z_{lt}^c - UY_{lt}^c) \quad (l = 1, \dots, NS) \quad (23)$$

$$\Delta QL_{lt}^{sc} - \sum_{b=1}^{NB} \frac{\partial QL_{lt}^{sc}}{\partial \theta_{bt}^c} \Delta \theta_{bt}^c - \sum_{b=1}^{NB} \frac{\partial QL_{lt}^{sc}}{\partial V_{bt}^c} \Delta V_{bt}^c \geq -M (2 - z_{lt}^c - UY_{lt}^c) \quad (l = 1, \dots, NS) \quad (24)$$

$$-M z_{lt}^c UY_{lt}^c \leq \Delta QL_{lt}^{sc} \leq M z_{lt}^c UY_{lt}^c \quad (l = 1, \dots, NS) \quad (25)$$

$$\Delta \delta_{lt}^{c \min} \leq \Delta \theta_{mt}^c - \Delta \theta_{nt}^c \leq \Delta \delta_{lt}^{c \max} \quad (26)$$

In (10), $\hat{z}_{lt}^c$ is the fixed value calculated by UC for Benders cuts. In power mismatch equations (11)-(12), slack variables would model system violations. Slack variables can be considered as virtual generators/loads that are added to each bus to mitigate mismatches. The right hand-side of (11) and (12) are the present value of power mismatch. Limits on reactive power generations and bus voltage magnitudes are presented by (13) and (14), respectively. The change in real and reactive power flows of non-switchable lines are obtained by (15)-(19). Considering the state of each switchable line, the change in switchable line flows are obtained by (20)-(25). These changes are used to update flows of switchable and non-switchable lines. The standing phase angle difference constraint is considered by (26). Note that $c=0$ denotes the base case. In (10) and (13), the double arrow refers to the duality of the equality constraint, where μ_{lt}^c and ψ_{it}^c represent the dual variable (simplex multiplier) of these constraints. Mathematically, a dual variable represents the marginal increment/decrement of the objective value when the variable is changed. When the state of the switchable line is zero the real power flow equation of that line will be relaxed by (20) and (21). Similarly, the reactive power flow equation will be relaxed by (23) and (24). In addition, the change in real and reactive power flows of that line will be set to zero by (22) and (25), respectively. So, the switched line will be completely removed from the system. M is a large positive constant and is calculated as proposed in [12].

For the base case, (27) is added to consider limits on real power generation. This constraint applies to all units except that of the slack bus, which is relaxed to compensate power loss calculations.

$$\Delta P_{it}^0 = 0 \leftrightarrow \pi_{it}^0 \quad (i = 2, \dots, NG) \quad (27)$$

In the case of contingencies, the adjustment range for unit generation at contingency with respect to the base case generation is considered. This constraint is presented by (28).

$$\Delta \Lambda_{it}^{\min} \leq \Delta P_{it}^c \leq \Delta \Lambda_{it}^{\max} \quad \leftrightarrow \quad \underline{\pi}_{it}^c, \overline{\pi}_{it}^c \quad (i = 2, \dots, NG) \quad (28)$$

In (28), only contingencies are considered, i.e. $c \geq 1$. For the limits on allowable post-contingency power generation redispatch we would have

$$\Delta \Lambda_{it}^{\max} = \Lambda_i - (P_{it}^c - P_{it}^0) \quad (29)$$

$$\Delta \Lambda_{it}^{\min} = -\Lambda_i - (P_{it}^c - P_{it}^0) \quad (30)$$

These limits define the maximum allowable adjustments of power generation output in case of contingencies. In the proposed formulation, small changes in state and control variables are subject to variable limits (31)-(36).

$$\Delta Q_{it}^{c \min} = Q_i^{\min} - Q_{it}^c \quad (31)$$

$$\Delta Q_{it}^{c \max} = Q_i^{\max} - Q_{it}^c \quad (32)$$

$$\Delta V_{bt}^{c \min} = V_b^{\min} - V_{bt}^c \quad (33)$$

$$\Delta V_{bt}^{c \max} = V_b^{\max} - V_{bt}^c \quad (34)$$

$$\Delta PL_{lt}^{c \min} = -PL_l^{\max} - PL_{lt}^c \quad (35)$$

$$\Delta PL_{lt}^{c \max} = PL_l^{\max} - PL_{lt}^c \quad (36)$$

The limits on standing phase angle difference are given as (37)-(40).

$$\Delta \delta_{lt}^{0 \min} = \delta_l^{\max} - (\theta_{mt}^0 - \theta_{nt}^0) + Mz_{l(t-1)}^0 + M(1 - z_{lt}^0) \quad (37)$$

$$\Delta \delta_{lt}^{0 \max} = \delta_l^{\max} - (\theta_{mt}^0 - \theta_{nt}^0) + Mz_{l(t-1)}^0 + M(1 - z_{lt}^0) \quad (38)$$

$$\Delta \delta_{lt}^{c \max} = \min \left\{ \begin{aligned} &\delta_l^{\max} - (\theta_{mt}^c - \theta_{nt}^c) + Mz_{l(t-1)}^c + M(1 - z_{lt}^c), \\ &\delta_l^{\max} - (\theta_{mt} - \theta_{nt}) + Mz_{lt} + M(1 - z_{lt}^c) \end{aligned} \right\} \quad (39)$$

$$\Delta \delta_{lt}^{c \min} = -\max \left\{ \begin{aligned} &\delta_l^{\max} + (\theta_{mt}^c - \theta_{nt}^c) + Mz_{l(t-1)}^c + M(1 - z_{lt}^c), \\ &\delta_l^{\max} + (\theta_{mt} - \theta_{nt}) + Mz_{lt} + M(1 - z_{lt}^c) \end{aligned} \right\} \quad (40)$$

In (39) and (40), where $c \geq 1$, the minimum and the maximum allowable changes in the standing phase angle difference would depend on the state of a switchable line in successive hours. In the case of contingencies, minimum and maximum allowable changes in the standing phase angle difference are determined based on two different modes of operation. The first mode represents the switchable line state at successive hours in that contingency, where excessive standing phase angle difference may exist when closing the line. The second mode represents the transition from the base case to a contingency. When a line is off at the base case and is switched back on in a contingency case, the standing phase angle difference of the line is checked. We

calculate the proper limits on changes of standing phase angle difference by comparing the values in these two modes.

To consider FACTS devices, (11) and (12) are modified since the proposed injections only appear in power mismatch equations at each bus. So, (11) is replaced by (41) and (12) is replaced by (42).

$$\sum_{i \in I_b} \Delta P_{it}^c - \sum_{l \in L_b^s} \Delta PL_{lt}^{sc} - \sum_{l \in L_b^{ns}} \Delta PL_{lt}^{nsc} + \sum_{b \in B_b} \alpha_{b,1} \Delta PF_{bt}^{Se,c} + MP_{bt,1}^c - MP_{bt,1}^c = dP_{0bt}^c \quad (b = 1, \dots, NB) \quad (41)$$

$$\sum_{i \in I_b} \Delta Q_{it}^c - \sum_{l \in L_b^s} \Delta QL_{lt}^{sc} - \sum_{l \in L_b^{ns}} \Delta QL_{lt}^{nsc} + \sum_{b \in B_b} \alpha_{b,2} \Delta QF_{bt}^{Se,c} + \sum_{b \in B_b} \alpha_{b,3} \Delta QF_{bt}^{Sh,c} + MQ_{bt,1}^c - MQ_{bt,1}^c = dQ_{0bt}^c \quad (b = 1, \dots, NB) \quad (42)$$

In the above formulations, coefficients are set to represent certain types of FACTS devices as follows [28]-[29]

Shunt controller: $\alpha_1 = 0, \quad \alpha_2 = 0, \quad \alpha_3 = 1$

Series controller: $\alpha_1 = 1, \quad \alpha_2 = 0, \quad \alpha_3 = 0$

Shunt-Series controller: $\alpha_1 = 1, \quad \alpha_2 = 1, \quad \alpha_3 = 1$

In every iteration, the FACTS control parameter limits are converted into associated PIM values for satisfying the operating constraints.

In the Base Case Network Check, if the total mismatch is greater than zero, the Benders cut (43) is formed and added to the master problem for the next iteration. The violation indicates that the existing UC solution cannot provide a feasible AC power flow solution. The required dual values that would generate cuts are obtained from (27) for power generation, from (13) for commitment state, and from (10) for switchable lines states.

$$\hat{w}_t^0 + \sum_{i=1}^{NG} (\pi_{it}^0 (P_{it}^0 I_{it} - \hat{P}_{it}^0 \hat{I}_{it}) + \sum_{i=1}^{NG} (\psi_{it}^0 Q_i^{\max} - \underline{\psi}_{it}^0 Q_i^{\min}) (I_{it} - \hat{I}_{it}) + \sum_{l=1}^{NL} \mu_{lt}^0 (z_{lt}^0 - \hat{z}_{lt}^0)) \leq 0 \quad (43)$$

where $\hat{w}_t^0$ is the current value of (9) in the base case. The number of Benders cuts is equal to the number of hours with power flow violations. These cuts provide proper signals for the convergence of AC power flow by re-calculating the hourly UC, dispatch, and the state of switchable lines in the next UC iteration. This iterative process stops when the base case violations are mitigated. In this case, the problem proceeds to the next step to consider different contingencies. In the Contingencies Network Check, if the total mismatch is greater than zero, the Benders cut (44) will be formed for the associated contingency in that hour and added to the UC for the next iteration.

$$\hat{w}_t^c + \sum_{i=1}^{NG} (\pi_{it}^c (P_{it}^c I_{it} - \hat{P}_{it}^c \hat{I}_{it}) + \sum_{i=1}^{NG} (\psi_{it}^c Q_i^{\max} - \underline{\psi}_{it}^c Q_i^{\min}) (I_{it} - \hat{I}_{it}) + \sum_{l=1}^{NL} \mu_{lt}^c (z_{lt}^c - \hat{z}_{lt}^c)) \leq 0 \quad (44)$$

where $\hat{w}_t^c$ is the current value of (9) in the case of contingencies. The following iterative procedure would provide the solution to the subproblems:

1) Calculate initial bus mismatches based on the UC solution and initial system states and settings.

- 2) Use linear programming (LP) to minimize (9) and calculate changes in system state and control variables (i.e., ΔQ , $\Delta \theta$, ΔV).
- 3) Update state and control variables, and calculate bus mismatches.
- 4) Again use LP to minimize (9) and calculate changes in the system state and control variables. If the difference between current and previous iterative changes is less than a specified threshold, stop the process. Otherwise, go back to Step 3.

3. NUMERICAL SIMULATIONS

A modified IEEE 118-bus system, shown in Fig. 3, is analyzed to illustrate the performance of the proposed model. The proposed model was implemented on a 2.4-GHz personal computer using CPLEX 11.0 [30]. This system has 118 buses, 54 units and 186 branches. The data for this system is found in motor.ece.iit.edu/data/SCUC_118test.xls. Twenty lines are considered switchable as shown in Table 2. Outages of unit 28, line 80-81, and line 85-89 are considered as credible contingencies. Standing phase angle difference limit of 20 degrees is considered for switchable lines. Three cases are considered as follows:

Case 1: Base case UC without network constraints

Case 2: Consider real network constraints in the SCUC solution with TS (DC solution)

Case 3: Consider real and reactive network constraints in the SCUC solution with TS (AC solution)

Case 1: In this case, UC will determine the base case schedule of units, when disregarding the network constraints. Seventeen units are committed at various hours to satisfy the forecasted load. Thirteen economical units are considered as base units, which are committed at the entire scheduling horizon. The other more expensive units are committed whenever necessary to meet the changes in the system load. The UC solution is obtained in 20s with a total operating cost of \$792,509.

Case 2: In this case, the hourly SCUC solution is considered with the DC model of the network. The unit schedule is shown in Table 3. In DC network model, voltage magnitudes at system buses are set to 1 and lines resistances are assumed to be zero. Consequently, the reactive load, reactive power generation capability of units and reactive power flow in the system are disregarded. The hourly schedule is quite different from that of Case 1, where the schedule for eleven units is changed. Most changes have occurred at the peak hour, i.e. hour 16, and its adjacent hours. At these hours, units 14, 19, 30, 34, 35 and 37 are turned on and unit 40 is turned off. Here, the generating unit 40 is turned off for economic reasons. The switchable line states are changed during scheduling hours to mitigate the system congestion and consequently increase the dispatch of economical units. The base case schedule for switchable lines is shown in Table 4, where seventeen switchable lines have changed their hourly states. Lines 90, 115 and 153 are in service at every hour, so their switching capability is not used in the problem solution. At the peak hour, only lines 75 and 164 are switched off to decrease the flow on lines 7, 9, 129, when all other lines are utilized to

supply loads. The system contingencies are handled with corrective actions (generation redispatch and TS). The standing phase angle difference of switched lines is checked whenever a line is switched back on, e.g., hour 7 for line 3, hours 7 and 11 for line 12, and so on. Here, none of the lines would exceed their standing phase angle difference limits, so it would be possible to switch the lines back as scheduled. The total operating cost is \$802,170, which shows a 1.22% increase in cost in comparison to that in Case 1. This increase is due to consideration of DC model of the network. This DC solution is obtained in 60s.

Case 3: In this case, the hourly SCUC solution is considered with the AC model of the network. The AC network model would include real and reactive power constraints. The constraints on bus voltage magnitudes are considered in this case. Table 3 highlights the revised hourly state of twenty units as compared to those in Case 2. In this case, most solution changes have occurred close to peak hours, except for units 43 and 44. Unit 43 is on at every hour to prevent voltage drops at buses 93, 94 and 102, and unit 44 is off for economic reasons. The switchable line schedule is shown in Table 5. Fifteen lines are switched hourly to satisfy the system constraints. The other five lines are switched at some hours. TS would increase the power transfer capability that could lead to hourly UC changes. TS would also adjust bus voltages and the reactive power dispatch of generating units by changing the network topology. The additional reactive power generated at the peak hour would lead to an overall increase in bus voltage magnitudes. At the peak hour, the smallest voltage magnitude is 0.97 at buses 44, 45, 109 and 118. On the other hand, 17 buses have already reached their upper limits which are adjusted subsequently by TS. TS would also influence voltages at other hours; however these changes do not have a significant effect on the system voltage profile as voltage magnitudes remain within their permissible limits. Fig. 4 depicts the voltage profile at bus 88 with and without TS. The bus is connected to generating units 38 and 40 at buses 85 and 89. Therefore, the two generating units would have the highest impact on the adjustment of voltage at bus 88. However, unit 38 is off and will not have an impact on the voltage at bus 88. We consider two alternatives as follows.

- Without TS: Unit 40 is committed at hours 9-18. In this case, the voltage magnitude at bus 88 is at its lower limit at hours 3-6 and close to its upper limit at hours 10 and 13-18. At hour 9, the voltage magnitude at bus 88 increases when unit 40 is committed. At hour 11, the voltage at bus 88 is affected by the change in the UC schedule. At hours 13-18, the voltage magnitude at bus 88 is close to its upper limit. At hours 19-24, the voltage at bus 88 drops because unit 40 which is the local source of voltage adjustment, is not in service.
- With TS: Unit 40 is committed at hours 10-22. In this case, the voltage at bus 88 is increased slightly at hours 3-7. The voltage magnitude at bus 88 increases at hour 10 when unit 40 is turned on. The UC adjustments at hour 11 would lead to a voltage magnitude drop at bus 88. At hours 13-14, the reactive power generation of unit 40 would increase the voltage magnitude at bus 88, while the TS application at hours 15-18 would decrease the voltage. The lower real and reactive power generation of unit 40 would decrease the reactive power flow on line 137 and voltage magnitude at bus 88. The commitment

of Unit 40 at hours 20-22 would supply the real and reactive power generation which would lead to an increase in the voltage magnitude at bus 88.

TS in Case 3 would provide a better chance for voltage adjustments especially at peak hour. At the peak hours, the additional real and reactive power generation supply the higher load. Using TS, voltage magnitudes could be lowered at peak hours which would increase the dispatch of less expensive units for supplying the load.

In Case 3, nine FACTS devices are considered with tap-changing and phase-shifting capabilities. The FACTS devices are modeled using the proposed PIM. In Case 2, where the DC network constraints are considered, the phase-shifting capability of FACTS devices will adjust the real power flow in the associated lines. In Case 3, the FACTS devices would also modify reactive power flows and accordingly adjust bus voltage levels. The FACTS devices generate a counterflow to decrease the power flow on the associated line and therefore increase the transfer capability of the line. The installed FACTS device at line 107 is between buses 68 and 69. The voltage at bus 69 is adjusted by the generating unit located at 29. Without the FACTS device at line 107, the voltage drop might occur at bus 68 mostly at peak hours. However, the reactive power injection to bus 68 increases the bus 68 voltage and prevents voltage violations. Fig. 5 shows the voltage profile of bus 68 with and without FACTS at line 107. Without the FACTS device, voltages are adjusted by the neighboring units 27, 29 and 54. Here, unit 54 is not committed while units 27 and 29 are always committed. The reactive power generation of units 27 and 29 is increased for adjusting the voltage level at bus 68, which would also increase the reactive power flow at connecting lines 104 and 107. The solid line in Fig. 5 shows the adjusted hourly voltage at bus 68. Comparing the two voltage profiles, the voltage deviation is smaller when FACTS devices are in place. So, the FACTS device could reduce the real and reactive power dispatch of units, decrease line flows, and enhance the use of TS. Similar to Case 2, TS would prevent the violation of standing phase angle difference limits. Hence, line flows and bus voltage magnitudes are within their limits when supplying the reactive loads. The total operating cost is \$824,342, which is calculated in 162seconds.

4. CONCLUSIONS

TS was incorporated into the SCUC problem with AC network constraints. To enhance the proposed AC solution of SCUC, FACTS devices were considered. A PIM was used to model the effect of FACTS devices in the AC power flow, using real and reactive power injections to system buses. We concluded that the TS applications would enhance the hourly SCUC solution when considering reactive and voltage constraints. In addition, the incorporation of FACTS devices would further enhance the proposed AC solution of SCUC. The incorporation of AC network constraints would increase the total operating cost and the execution time, which is regarded as a trade-off between more accurate and faster SCUC solutions.

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Figure Captions:

Fig. 1 Flowchart of SCUC with TS for reactive power management

Fig. 2 Power injection model of FACTS devices

Fig. 3 IEEE 118-bus system

Fig. 4 Voltage profile at bus 88

Fig. 5 Voltage profile at bus 68

Fig. 1 Flowchart of SCUC with TS for reactive power management

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Table Titles:

Table 1 Power Injection Model Components of FACTS devices

Table 2 Switchable Line Data

Table 3 UC Schedule of IEEE 118-Bus System in Case 2

Table 4 Switchable Line Schedule of IEEE 118-Bus System in Case 2

Table 5 Switchable Line Schedule of IEEE 118-Bus System in Case 3

Table 1 Power Injection Model Components of FACTS devices

Controller Type	FACTS Device	Steady State Function	Control Variable
Series	TCPS	Real power flow control	PF^{Se}
	TCSC		
	SSSC		
Shunt	SVC	Voltage regulation	QF^{Sh}
	STATCOM		
Shunt-Series	UPFC	Real and reactive power flow control	$PF^{Se}, QF^{Se}, QF^{Sh}$
		Voltage regulation	

Table 2 Switchable Line Data

Line No.	From Bus	To Bus	R (pu)	X (pu)	Charging (pu)	Flow limit (MW)
3	4	5	0.002	0.008	0.002	500
12	11	12	0.006	0.020	0.005	100
16	11	13	0.022	0.073	0.019	100
23	17	18	0.012	0.051	0.013	100
30	23	24	0.014	0.049	0.050	100
40	29	31	0.011	0.033	0.008	100
43	27	32	0.023	0.076	0.019	100
59	43	44	0.061	0.245	0.061	100
67	42	49	0.072	0.323	0.086	100
75	49	54	0.073	0.289	0.074	100
78	54	56	0.003	0.010	0.007	100
90	60	61	0.003	0.014	0.015	500
100	62	66	0.048	0.218	0.058	100
115	70	75	0.043	0.141	0.036	100
151	80	97	0.018	0.093	0.025	100
153	80	99	0.045	0.206	0.055	100
159	99	100	0.018	0.081	0.022	100
164	100	104	0.045	0.204	0.054	100
167	100	106	0.061	0.229	0.062	100
181	27	115	0.016	0.074	0.020	100

Table 3 UC Schedule of IEEE 118-Bus System in Case 2

[illegible]

SCUC with Hourly Demand Response Considering Inter-temporal Load Characteristics

Amin Khodaei, *Member, IEEE* and Mohammad Shahidehpour, *Fellow, IEEE*

Abstract— In this paper, the hourly demand response (DR) is incorporated into security-constrained unit commitment (SCUC) for economic and security purposes. SCUC considers fixed and responsive loads. Unlike fixed hourly loads, responsive loads are modeled with their inter-temporal characteristics. The responsive loads linked to hourly market prices can be curtailed or shifted to other operating hours. The study results show that DR could shave the peak load, reduce the system operating cost, reduce fuel consumptions and carbon footprints, and reduce the transmission congestion by reshaping the hourly load profile. Numerical simulations in this paper exhibit the effectiveness of the proposed approach.

Index Terms—Demand response, Security constrained unit commitment, Real time prices

Indices:

b	Index for bus
i	Index for unit
t	Index for time

Sets:

f	Superscript for fixed loads
r	Superscript for responsive loads

Parameters:

NB	Number of buses
NG	Number of units
NT	Number of time periods (hours)
$EX_b^{\max}$	Max curtailable daily load at bus b
D_{bt}^f	Fixed load at bus b at time t
$D_{bt}^{r,\max}$	Submitted responsive load at bus b at time t
$DX_{bt}^{\min}$	Min curtailable load at bus b at time t
DR_b	Drop off rate of load at bus b
UR_b	Pickup rate of load at bus b
UT_b	Min up time of load at bus b
DT_b	Min off time of load at bus b
X_{bt}^{on}	ON time of load at bus b and time t
X_{bt}^{off}	OFF time of load at bus b at time t

Variables:

CB_{bt}	Consumption benefit at bus b at time t
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D_{bt}	Load at bus b at time t
D_{bt}^r	Responsive load at bus b at time t
GC_{it}	Generation cost of unit i at time t
I_{it}	Commitment state of unit i at time t
P_{it}	Generation of unit i at time t
v_{bt}	Curtailment state of load at bus b at time t
w_t	Power mismatch at time t
μ_{bt}, π_{it}	Dual variables

Symbols:

$\wedge$	Given variables
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I. INTRODUCTION

IN RESTRUCTURED power systems, the independent system operator (ISO) would schedule available system resources to satisfy the hourly system load and maintain the system security at the least operating cost [1]–[2]. The hourly system load could be fixed in the day-ahead scheduling. The participating generating companies would submit strategic bids to the ISO to supply the hourly load forecast [3]. The market clearing price would be set by the marginal price of the last scheduled generator for satisfying the hourly fixed load. Hence, the demand-side would have no role in the market clearing and price setting. Some of drawbacks of the lack demand-side participation in power markets could include large price spikes, congested transmission lines, higher fuel consumptions and carbon footprints, lack of sufficient generation resources in particular at peak hours, and exercise of market power [4]–[8].

Price spikes might occur when the demand-side has no role in setting electricity prices, so generators would have no incentive to bid close to their marginal costs which could lead to bids that are much higher than actual generation costs. This behavior could lead to volatile market prices that are away from perfectly competitive prices. In addition, price spikes might happen when generation reserves are lower during peak demand hours. To compensate generation shortages at peak hours, generators with high marginal costs are installed to supply peak demands, which could result in a significant underutilization of such generators at off-peak periods.

Demand-side participation could be very effective in such circumstances. Demand-side participation may reduce the load at peak periods, which is a more economical way to respond to generation and transmission capacity constraints. The demand-side participation could also mitigate price manipulations

which could otherwise lead to market power exercises. The price manipulations could occur when the hourly generation dispatch is calculated by minimizing the total operating cost (without considering any demand-side participation.) An increase in the demand-side participation could benefit individual customers and ultimately the entire electricity market.

Demand-side participation could include distributed generation, on-site storage, and demand response (DR). DR is considered more specifically in this paper. DR includes the reduction or deferral of hourly consumptions in response to higher market prices or market incentives [4]-[5]. DR could include the emergency DR and the economic DR. Emergency DR will reduce the load temporarily in response to an emergency grid condition initiated by a request from system operators. This type of DR is not frequently used and not considered in this paper. Economic DR will reduce the load voluntarily by electricity customers and in response to market prices. In restructured power systems, nodal prices vary with time and location; so electricity customers could adjust their load profiles in response to electricity price volatilities. Customers could curtail loads in such circumstances. However, load curtailments are usually undesirable. Customers would rather shift less critical loads to hours with more moderate prices [9]-[13]. All customers would, however, benefit from lowered market prices as shifting five to eight percent of the consumption to off-peak hours and shedding additional four to seven percent of peak demand could save U.S. customers about \$15 billion a year [14].

Fig. 1 depicts the energy market operation in a restructured power system. Generation and transmission companies provide the ISO with the available generating unit and transmission line information. The load serving entity (LSE) which acts as an aggregator for customer loads provides the load data to the ISO. The customers do not directly participate in DR programs and the curtailment service provider (CSP) acts on behalf of such customers. CSP obtains load curtailment data from customers and submits DR bids to the ISO. In addition, it provides customers with curtailment options and saving opportunities, in day-ahead and real-time markets, based on forecasted prices. Note that an LSE or electric distribution company (EDC) could act as a CSP. The ISO runs the day-ahead security-constrained unit commitment (SCUC) based on the prevailing constraints to find the optimal hourly schedule of generating units and loads.

The challenge here is to incorporate DR into the market clearing process to achieve the most efficient market dynamics [16]-[17]. [13] incorporated DR within auction rules using an iterative approach. An auction algorithm to implicitly allow DR is developed in [17], but the periods for reducing loads or recovering the saved energy are fixed. In [18] an alternative market-clearing tool is proposed for maximizing the social welfare in which customers submit bids for energy purchases. In [19] a multi-round auction algorithm is introduced in which market participants would modify their bids until an equilibrium is reached. The iterative algorithm may cause market price oscillations. In [20] load constraints are incorporated into day-ahead auctions using an hourly bidding

mechanism. However, most of temporal constraints of loads and transmission constraints are disregarded. [21] quantifies the effect of DR on electricity markets in which the load shifting behavior of customers is considered in a centralized market-clearing mechanism. In [22] the elasticity of demand is incorporated in a centralized market-clearing process. [23] further explored the approach proposed in [22] using a unit commitment (UC) instead of optimal power flow calculation for market clearing. The iterative process used in [22] integrates the market price computation with the elasticity of demand price. In [24] the iterative market-clearing process proposed in [22]-[23] is revisited and convergence problems encountered in those approaches were alleviated.

Fig. 1 Energy market components

In general, either a direct approach or an iterative approach is used when considering DR in market clearing processes. The iterative approaches use the elasticity of demand price to adjust the load demand. However, convergence problems may occur in the iterative process which would be time-consuming; it could also be difficult to guarantee the existence of a feasible solution. Direct methods do not accurately model the shifting of responsive loads which could have a significant impact on market-clearing results. In addition, these approaches do not consider operating constraints of DR nor do they consider transmission constraints.

In this paper, we propose a DR model for market clearing. Responsive loads are considered which can be curtailed or shifted in time for economical reasons. The operating characteristics of loads including bids, hourly profile, and temporal characteristics, are considered which are submitted to the ISO. An hourly SCUC is applied for market clearing (see Fig. 1) in which the network feasibility in the base case and contingencies are taken into account. So the impact of DR on

the hourly operation and control of constrained power systems is considered in the proposed approach.

The rest of the paper is organized as follows. Section II outlines the proposed day-ahead market clearing model, while Section III formulates the problem. The numerical studies are provided in Section IV, the observations are listed in Section V and the paper is concluded in Section VI.

II. DAY-AHEAD MARKET CLEARING MODEL

The proposed market-clearing process with DR is presented in this section.

A. Market clearing process

We assume both generators and loads could submit complex offers and bids to the ISO. Complex load bids include multiple bid sections with inter-temporal load constraints. When considering simple generation offers and load bids, the market-clearing price is the cross section of aggregated load and generation quantities. In our approach, transmission constraints are considered in the base case and contingencies. The objective would be to maximize the social welfare, i.e. consumption payments minus generation costs. The hourly SCUC schedule for complex bids would demonstrate the optimal commitment and dispatch of generating units and the hourly DR based on submitted offers and bids.

B. Load bids

DR bids include hourly fixed and responsive load bids. Fixed loads are price-takers which are satisfied at the market-clearing price. The responsive load price would drop with increasing the load quantity. A responsive load bid consists of hourly quantity and price of load which are subject to the following constraints [25]-[26]:

- Minimum up/down time limits
- Load pickup/drop rates
- Minimum hourly curtailment
- Maximum daily curtailment

Minimum up time defines the number of consecutive hours that the load would have to be supplied once it is restored. Minimum down time represents the minimum number of consecutive hours that a load would be off once curtailed. Load pickup/drop rates represent the ramping capability for restoring/curtailing loads. These rates identify the rate at which a customer would change its consumption. The minimum hourly curtailment defines the lower limit for the allowable hourly curtailment. The minimum load curtailment may either reflect physical load limits or be imposed by system operators whereby smaller responsive loads could not participate in markets. The maximum daily curtailment would restrict the total load curtailment in the scheduling horizon. A feasible hourly schedule for responsive loads is calculated using these physical constraints.

C. Hourly SCUC Solution with DR

The proposed flowchart is depicted in Fig. 1. The solution of the master problem consists of optimal day-ahead commitment and dispatch schedule of generating units and loads. The solution of the master problem is applied to the

subproblem 1 to check the feasibility of the system when considering the base case transmission system constraints. In the case of violations, hourly Benders cuts are generated and added to the master problem in the next iteration. This iterative process will continue until an optimal base case solution is achieved. The solution of the master problem is further used in the subproblem 2 to check the system feasibility in the case of contingencies. In the case of violations, Benders cut is added to the next iteration of the master problem. This iterative process will continue until the system security constraints are satisfied. The Benders cuts in this problem would include one additional variable, i.e. load quantity, as we solve the SCUC problem [27]-[31].

III. FORMULATION OF SCUC WITH DR

The SCUC formulation in the master problem and two subproblems is presented in the following.

A. Master Problem

The objective of the master problem is to determine the day-ahead schedule of generating units and loads in order to maximize the system social welfare while satisfying the prevailing unit, load and system constraints. The objective is shown in (1):

$$\text{Max} \sum_{t=1}^{NT} \sum_{b=1}^{NB} CB_{bt} (D_{bt}) - \sum_{t=1}^{NT} \sum_{i=1}^{NG} GC_{it} (P_{it}) \quad (1)$$

The objective is to maximize the system social welfare, which is the consumption benefit minus the generation cost. This objective is subject to power balance constraint (2)

$$\sum_{i=1}^{NG} P_{it} - \sum_{b=1}^{NB} D_{bt} = 0 \quad (t = 1, \dots, NT) \quad (2)$$

In (2), both generation and load are considered as variables. Other system constraints include system spinning/operating reserve requirements, system fuel limits, and system emission limits. Unit constraints include unit output limits, unit spinning/operating reserve limit, ramp up/down rate limits, min up/down time limits, fuel limits, and emission limits.

The bus load consists of fixed and responsive terms (3). The fixed load term should be fully satisfied. The responsive load term can be curtailed or shifted to another operating hour when the electricity price is cheaper. The cost of supplying the fixed load is not considered. Therefore, the objective function of SCUC would only include responsive load bids.

$$D_{bt} = D_{bt}^f + D_{bt}^r \quad (b = 1, \dots, NB)(t = 1, \dots, NT) \quad (3)$$

A typical DR bid curve is depicted in Fig. 2 which includes fixed and step-wise responsive load bids. The fixed load, minimum load curtailment, and maximum level of responsive load submitted to the ISO are denoted by A , B and C , respectively in Fig. 2. The responsive load constraints are formulated as follows.

$$[D_{bt}^{r, \max} - DX_{bt}^{\min} - D_{bt}^r]v_{bt} \geq 0 \quad (b = 1, \dots, NB)(t = 1, \dots, NT) \quad (4)$$

$$D_{bt}^r v_{bt} \geq 0 \quad (b = 1, \dots, NB)(t = 1, \dots, NT) \quad (5)$$

$$[D_{bt}^r - D_{bt}^{r, \max}] [1 - v_{bt}] \geq 0 \quad (b = 1, \dots, NB)(t = 1, \dots, NT) \quad (6)$$

$$D_{bt}^r - D_{b(t-1)}^r \leq UR_b \quad (b = 1, \dots, NB)(t = 1, \dots, NT) \quad (7)$$

$$D_{b(t-1)}^r - D_{bt}^r \leq DR_b \quad (b = 1, \dots, NB)(t = 1, \dots, NT) \quad (8)$$

$$[X_{b(t-1)}^{on} - UT_b][v_{b(t-1)} - v_{bt}] \geq 0 \quad (b = 1, \dots, NB)(t = 1, \dots, NT) \quad (9)$$

$$[X_{b(t-1)}^{off} - DT_b][v_{bt} - v_{b(t-1)}] \geq 0 \quad (b = 1, \dots, NB)(t = 1, \dots, NT) \quad (10)$$

$$\sum_{t=1}^{NT} (D_{bt}^{r,max} - D_{bt}^r) \leq EX_b^{max} \quad (b = 1, \dots, NB) \quad (11)$$

In this formulation, the responsive load, i.e. D_{bt}^r , and the curtailment state of load, i.e. v_{bt} , are variables. The curtailment state is 1 when the load is curtailed and is 0 otherwise. The curtailed load is the difference between the maximum and the scheduled responsive loads. The curtailed load is larger than the minimum load curtailment. Since the curtailed load is not directly considered in the formulation, its associated constraints are represented by the responsive load. The possible cases are listed as follows:

- The proposed curtailed load is less than the minimum load curtailment. In this case the minimum load curtailment constraint (4) would be imposed. The scheduled responsive load would be the submitted responsive load minus the minimum load curtailment.
- The proposed curtailed load is larger than the minimum load curtailment: in this case, constraint (5) would ensure that the scheduled responsive load is nonnegative.
- Load is not curtailed: in this case the submitted responsive load will be scheduled. Constraint (6) would be enforced and loads will be shifted to this hour.

Fig. 2 DR bid curve

The hourly load pickup/drop rates constraints (7)-(8) would limit the rate of load changes between any two successive hours. The minimum load up/down time constraints (9)-(10) indicate that the minimum number of hours when the load cannot be curtailed/restored. Constraint (11) restricts the total daily load curtailment. The hourly load curtailment is the difference between the submitted responsive load and the scheduled responsive load. This term is positive when the load is curtailed, negative when the load is shifted to that hour, and zero when there is no load curtailment or shifting at that hour. Using this constraint, responsive loads may be shifted or curtailed.

B. SCUC Subproblems

The solution of the master problem, i.e. the hourly unit commitment and dispatch as well as load schedule, is used in

the base case and contingencies network check subproblems to examine the feasibility of the master solution for satisfying the network security. The objective of the subproblems is to minimize power mismatches in all system buses. In the case of violations, hourly cuts (12) are provided to the UC problem as

$$\hat{w}_t + \sum_{i=1}^{NG} \pi_{it} (P_{it} I_{it} - \hat{P}_{it} \hat{I}_{it}) + \sum_{b=1}^{NB} \mu_{bt} (D_{bt} - \hat{D}_{bt}) \leq 0 \quad (12)$$

Here, $\hat{w}_t$ denotes the current bus power mismatch in the base case; π_{it} and μ_{bt} are respectively the dual variables of hourly unit dispatch and load balance equations. The second and third terms respectively represent the change in the objective value (power mismatch) when the unit schedule and load schedule are changed. The cut indicates that current violations in the base case can be mitigated by recalculating the schedule of units and loads. In the case of contingencies, corrective actions are introduced by generation redispatch. In the case of violations, the hourly cuts for the UC problem are

$$\hat{w}_t + \sum_{i=1}^{NG} (\bar{\pi}_{it} - \underline{\pi}_{it}) (P_{it} - \hat{P}_{it}) + \sum_{b=1}^{NB} \mu_{bt} (D_{bt} - \hat{D}_{bt}) \leq 0 \quad (13)$$

Here, $\bar{\pi}_{it}$ and $\underline{\pi}_{it}$ are dual variables of hourly generation redispatch constraints and μ_{bt} is the dual variable of load balance equation; $\hat{w}_t$ denotes the current bus power mismatch in the case of contingencies and the second and third terms respectively represent changes in the objective value (power mismatch) when the unit dispatch and load schedule are changed.

The iterative process between the master problem and subproblems continues until all contingencies are handled properly and system security conditions in the base case and contingencies are satisfied [25].

IV. NUMERICAL SIMULATIONS AND DISCUSSIONS

A modified IEEE 118-bus system is analyzed to illustrate the performance of the proposed method. The proposed method was implemented on a 2.4-GHz personal computer using CPLEX 11.0 [32]. The system has 118 buses, 54 units and 186 branches. The data for this system is given in motor.ece.iit.edu/data/SCUC_118test.xls. The following cases are considered for analyzing the effect of DR in SCUC.

A. DR considered at a single bus

Bus 59 is considered as the bus with DR. 10% of the total load in this bus is considered as responsive while the rest is fixed. A single-step consumption bid of 20\$/MWh is considered for the responsive load. The minimum and maximum hourly load curtailment of 5 MW and 150 MW are considered for this load. The minimum up and down times are 4 hours and the load pickup and drop rates are considered large enough to allow any load changes in successive hours. The following cases are considered:

Case 0: Base case SCUC with no DR

Case 1: DR in Case 0 (with load curtailment)

Case 2: DR in Case 0 (with load shifting)

Case 0: We assume that the load is fixed (DR is not considered) in SCUC. The calculated total operating cost in

this case is \$1,046,785.81. Forty five units are committed and the load at bus 59 is fully satisfied.

Case 1: In this case, 10% of the hourly load at bus 59 is considered as responsive load. Assume that this load can only be curtailed (cannot be shifted.) Accordingly, the operating cost is dropped to \$1,042,325.48 (i.e., 0.43% decrease in the operating cost.) The actual and curtailed loads at bus 59 are depicted in Fig. 3. The load curtailment occurs at hours 14-19. The curtailment at hour 14 is 14.4 MW. At hours 15-19, the curtailed load is 26.9, 27.7, 27.7, 26.7 and 26.6 MW, respectively, which are equal to maximum hourly curtailable loads, and the total load curtailment is equal to the daily curtailment limit of 150 MW. The hourly load curtailment occurs near the peak hour which changes the scheduled unit commitment when units 2 and 9 are turned off. The total saving at bus 59 is \$16,265.50 with a 4460.33 MBtu saving in fuel consumption.

Case 2: Fig. 4 depicts the application load shifting at bus 59. The load at hours 12-19 is shifted. However, the total energy consumption at bus 59 is not changed. The minimum load of 5 MW was shifted at hour 12. Load shifting changes the unit commitment schedule when nine expensive units are no longer committed at the peak hour. The total operating cost is \$1,044,998.12 (i.e., 0.17% decrease) which is larger than that of Case 1 when the load was curtailed. The total saving in load consumption at bus 59 is \$10378.15 with a 1787.69 MBtu saving in fuel consumption.

Fig. 3 Load at bus 59 with load curtailment

Fig. 4 Load at bus 59 with load shifting

In Cases 1 and 2, the average system LMP is decreased in four hours. The average system LMP in Cases 0 and 1 are compared in Fig. 5. The hourly LMP in the entire scheduling horizon is affected, although the load curtailment is at hours 14-19. Here, a less congested network flows would result in lower LMPs. The average system LMP in Case 2 is fairly similar to that of Case 1, while the LMP at hours 21 and 22 is

slightly higher. The load shifting could mitigate price spikes and lower the average system LMP as efficiently as load curtailment.

Fig. 5 Average system LMP

B. DR considered at all buses

In this case, DR (load shifting) is considered at all buses when calculating the hourly SCUC. The load is shifted from 0% to 20% with steps of 5%. Here, 20% means that one fifth of the hourly load may be shifted. Four cases are considered as follows:

Case 0: SCUC solution with DR

Case 1: SCED solution with DR

Case 2: Effect of contingencies on Case 0

Case 3: Effect of load pickup/drop rates on Case 0

Case 0: In Table I, the number of committed units and the total operating cost are reduced as we shift more loads away from peak hours. In Table I, the largest cost drop occurs during the first 5% step with a 1.32% reduction in the cost.

TABLE I
SCUC RESULTS WITH A VARIETY OF DR

Responsive load (%)	Total operating cost (\$)	Number of committed units	Hourly load average	Hourly load standard deviation
0	1,046,785.89	45	3,048.10	537.67
5	1,033,506.86	33	3,048.10	346.68
10	1,030,887.89	29	3,048.10	200.31
15	1,030,191.46	25	3,048.10	70.86
20	1,030,018.28	23	3,048.10	22.09

Without any load shifts, 44 units are committed with 15 units operating as base units. With a 5% DR, the number of committed units is decreased to 34 with 16 units operating as base units. The number of committed units would decrease progressively in this case with more units operating as base unit. The hourly load average (total daily load divided by 24) is fixed as curtailment is not considered. However the standard deviation is reduced as we shift more loads which would result in a flatter load profile (i.e., hourly system load gets closer to the average load.) In Fig. 6, the 20% load shift is compared with the actual system load. The small change at hour 7 is due to the commitment of unit 19, which is the latest committed unit. The total shifted load is 5,711 MW which is shifted from hours 11-22 to hours 1-10 and 23-24. With a flat load profile, there will be no need to commit expensive units at peak hours.

Fig. 6 Actual and shifted system loads

Fig. 7 Average system LMP

Fig. 8 Reduction in fuel consumption

Fig. 9 Actual and shifted system load in the case of contingencies

Here, by shifting loads to off-peak hours, line flows decrease at peak hours (i.e., less congestion) and increase at

off-peak hours. The average LMP depicted in Fig. 7 which is much more flat with possible load shifts. The reduction in fuel consumption is shown in Fig. 8.

Case 1: In Case 0, there was an iterative process in the SCUC solution in which the UC solution was modified in each iteration in order to optimize the DR solution. Here, we fix the base case UC results in Table 1 and utilize an SCED with the 20% DR. Accordingly, a unit dispatch is obtained with a total operating cost of \$1,039,343.61 which is 0.9% higher than that of the SCUC result. The standard deviation is 400 MW with a total load shift of 1,529 MW. Here the cost is higher because the fixed UC solution would restrict the load shifts and the DR benefits presented in Case 0.

Case 2: Three possible contingencies including the outages of unit 10 and line 120 at peak hour and the outage of unit 19 at hour 5 are considered. Accordingly, the original unit commitment is adjusted and loads are shifted as preventive actions. However, possible corrective actions would be handled by the hourly generation dispatch and load curtailments. If we do not shift any loads, 48 units are committed to satisfy the load with a total operating cost of \$1,060,349.50. When we consider a 20% load shift, the total operating cost is reduced to \$1,035,364.42 in which only 25 units are committed. The hourly load standard deviation is 60 MW, which is larger than that of Case 0. This is due to the commitment of additional units at hours with contingency. Unit 23 is committed at hours 15-19 to handle the outage of unit 10; also unit 16 is committed at the entire scheduling horizon. Accordingly the dispatch of units and load shifts are modified. In UC, units 10, 19, and 23 are partially committed while the other committed units are always on. By shifting loads, the partially committed units will be loaded additionally and, as shown in Fig. 9, the load profile will not be as flat.

Case 3: In this case load pickup/drop rates of 0.5 MW/min are considered. The SCUC with 20% DR is solved. The load pickup/drop rates would reduce the responsiveness of loads in seventeen buses as compared to Case 0. Accordingly, the load schedule in the entire system is changed to compensate the reduced load shifting capability of affected buses. The total operating cost is slightly increased as the total savings for loads subject to pickup/drop rates are decreased. This decrease in savings is due to fewer load shifting. Fig. 10 shows the DR solution which is compared with the actual system load.

Fig. 10 Actual and shifted system load with load pickup/drop rates

In Fig. 11, the responsive load of bus 54 could change much faster when load pickup/drop rates are not considered. The load changes are as high as 59 MW (between hours 11 and 12 and hours 12 and 13). However when considering the load pickup and drop rates, the responsive load would only change 30 MW from hour 8 to hour 9 and from hour 9 to hour 10.

Fig. 11 Effect of load pickup/drop rates on responsive load at bus 54

V. OBSERVATIONS

Using the studied cases, we list the DR advantages as follows:

- Peak demand reduction. This reduction was by either curtailing peak demands or shifting peak demands to off-peak hours. The peak load reduction would mitigate price spikes and enhanced economical dispatch.
- Reduction in the average system LMP. Changes in DR-based hourly load profile could modify the hourly unit commitment and power flows, and accordingly reduce bus LMPs.
- Social benefits of DR. Any DR applications to a fraction of buses could provide benefits to the entire power system and all market participants.
- DR in day-ahead. DR application was more beneficial to SCUC than to SCED. The corresponding adjustments to SCUC would enhance the flexibility and the efficiency of market operations.
- Higher DR. Additional level of DR would lead to better SCUC results and a more flat hourly load profile. However, merits of very large DR were not as significant.
- Impact of DR on power system operation. A higher DR would lead to lower fuel consumptions and reduced carbon footprint in power systems.

VI. CONCLUSIONS

The ability to curtail or shift loads at peak periods could reduce the energy cost and require few on/off commitment of generating units. In this paper a comprehensive formulation is proposed to model the DR in the clearing process of electricity markets. The application of DR to SCUC would effectively incorporate responsive loads in the day-ahead market operations. Physical constraints of responsive loads along with generation units and transmission lines were considered. Such constraints were considered in base case and contingency operations of the system. The benefits of DR were demonstrated as viable options for managing the load growth

in electric power systems.

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Optimal Coordination of Stochastic Hydro and Natural Gas Supplies in Midterm Operation of Power Systems

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Abstract—This paper presents a stochastic security-constrained unit commitment (SCUC) model for the optimization of coordinated midterm water and natural gas supplies. The stochastic model considers random outages of system components, load forecast errors, and water inflow uncertainty, which are modeled as scenarios in the Monte Carlo (MC) simulation. Water resources may be used in winter to cover gas unit outages caused by an insufficient gas supply. However, those hydro units may not then be available for peak load shaving in the following summer if the summer happens to be a dry season. Thus, water reservoirs would have to be utilized efficiently throughout the year to provide substantial cost reductions while maintaining the power system reliability. The proposed model also considers the impact of midterm security-constrained scheduling of water and gas on the power system reliability. Accordingly, hourly SCUC is incorporated in the reliability calculation. The proposed stochastic problem is formulated as a two-stage optimization in which the first stage optimizes the water and gas usages in the first month and the second stage considers the schedule via multiple scenarios in the following eleven months. Numerical simulations indicate the effectiveness of the proposed stochastic approach for the optimal scheduling of midterm water and gas usages.

Keywords: Midterm water and natural gas supplies, power system reliability, stochastic security-constrained unit commitment

NOMENCLATURE

Variables:

b, c	Index of bus/catchment
$F_c(\cdot)$	Production cost function of a unit
h, i	Index of hydro/thermal unit
I_{itp}^s, P_{itp}^s	Commitment state and real power generation of thermal unit i at time t at period p in scenario s
j, k	Index of iteration
$LS_{btp,m}^s$	Load shedding quantity of contract m at bus b at time t at period p in scenario s
m	Index of curve segments
p, t	Index of period, and hours in each period
SU_{itp}^s, SD_{itp}^s	Startup/shutdown cost of thermal unit i at time t at period p in scenario s
V_{htp}^s	Reservoir volume of hydro unit h at time t at period p in scenario s
β	Lagrangian multiplier
γ_{ctp}^s	Global parameter for catchment c describing its depletion policy at time t at period p in scenario s
$\gamma_{h,m}$	Global parameter corresponding to hydro unit h at segment m in linearized depletion curve
$\delta_{h,m}$	Indicates whether hydro unit h is operated at segment m in linearized depletion curve
$v_{h,m}$	Volume of segment m in linearized depletion curve for hydro unit h

Constants:

$IC_{h,m}$	Slope of segment m in linearized depletion curve for hydro unit h
NB, NC	Number of buses/catchments

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NG , NH	Number of thermal/hydro units
NH_c	Number of hydro units belongs to catchment c
NPD , NPS	Number of periods at the first/second stage under study
NM_b	Number load shedding contracts at bus b
NS	Number of scenarios
NT	Number of hours at each period
p^s	Probability of scenario s
PL_{tp}^s	System load at time t at period p in scenario s
$pV_{b,m}^s$	Value of lost load (VOLL) corresponding to segment m of bus b in scenario s
$V_{h,max}$, $V_{h,min}$	Upper/lower limit of reservoir volume of hydro unit h
$V_{h,m}$	Upper volume limit of segment m in linearized depletion curve for hydro unit h

Note: Corresponding variables are also considered for hydro units by changing index i to h .

1 INTRODUCTION

In restructured power systems, ISOs maintain the power system reliability when supplying the hourly load at minimum cost [1]. In this environment, the interdependency of natural gas and electric power systems could affect the security and the economics of power systems. For instance, in winter months when residential usages of gas increases in some regions, there may be an insufficient level of gas available for gas-fired generating units. Hydro units could be used in such occasions in order to avoid electric load curtailments. However, if the following spring season happens to be dry, water reservoirs utilized in the previous winter would not be replenished. Thus insufficient water resources could lead to the inability of hydro units to supply summer peak loads. In order to minimize peak load curtailments in the coming summer months, water usage has to be limited in the winter by committing more expensive thermal units.

The uncertainty of water inflow introduces a relationship between present and future reservoir operation decisions in a cascaded hydro system as shown in Figure 1. Here, at the optimal point, future and current water values are equal. Water values are calculated as incremental/decremental costs for reducing/adding stored water at the final level in the current period.

Figure 1 Immediate and future costs versus final water storage

The midterm (i.e., several months to one year) optimization of cascaded hydro units is a difficult task because a reservoir's operation strategy may affect downstream reservoirs' energy production and water quantity. In addition, large dimensions, temporal, and stochastic characteristics of cascaded hydro systems would require fairly accurate solutions with reasonably low computation costs. In [3] and [4], the storage capacity of cascaded reservoirs in a system was aggregated into a single composite reservoir which reduced the number of state variables for long-term studies. The storage and release policies for each reservoir were then disaggregated using heuristic rules. The main drawback of the single composite reservoir model lies in the difficulty to derive feasible/optimal operation policies for individual reservoirs from the aggregate policy. [5] proposed a linear marginal cost model to optimize the long-term hydro unit scheduling, which was derived from the composite marginal cost function of a thermal system. The difficulty would be to derive the composite thermal cost function, especially when incorporating the power transmission network. An overview of the state-of-the-art optimal operation of cascaded reservoir systems was given in [6].

The gas transmission system may affect the operation of power systems with gas-fired generation units. Pressure losses, pipeline contingencies, lack of storage or gas supply disruptions may lead to forced outages of multiple

gas-fired units or generation deration. Such events could dramatically increase the power system operating costs and transmission congestion and jeopardize its security [7]. The scheduling of gas-fired combined cycle units could represent a complicated optimization problem because such units could have multiple operating configurations based on the number and the status of combustion and steam turbines. [8] presented an optimization method for establishing the state space diagram of combined cycle units and applying dynamic programming and Lagrangian relaxation to the security-constrained short-term scheduling of power systems with gas-fired combined cycle units. Nonlinear optimization models for the integrated operation of gas and power systems were discussed in [9], [10]. The impact of gas transmission charges on power markets was discussed in [11]. [12] proposed an integrated model for assessing the impact of interdependency of electricity and gas networks on power system security. The gas network is modeled by considering daily and hourly limits on pipelines, sub-areas, plants, and generating units. [13] proposed an integrated model for UC with gas transmission constraints, which were formulated as nonlinear equations and solved by a Newton-Raphson method. Successive Benders Decomposition (BD) was applied to separate the gas transmission feasibility check subproblem from UC problem. The same methodology is applied here to incorporate gas network constraints into the power system optimal operation problem.

The midterm water allocation could impact the reliability of power systems. [14] modeled hydro unit production using two different methods, i.e., through peak shaving or by dispatching hydro units against the equivalent load duration curve (ELDC). It concluded that the ELDC-based approach would generally result in lower production costs and higher reliability by applying hydro units to cover thermal unit outages. [15] incorporated reliability into a UC framework by developing loss-of-load-expectation (LOLE) and expected-energy-not-served that provided useful information on long-term operating decisions. Additional details on reliability evaluation methods were given in [16].

In this paper, the reliability assessment of power systems is analyzed for the midterm optimal water and gas usages. Since the midterm operation of cascaded reservoirs is coupled in time and space, there is a trade-off between operating cost and supply reliability. Because it is impossible to have prior knowledge of future water inflows, power and gas loads, as well as power system disturbances, this trade-off can only be expressed on a stochastic basis. Uncertainties are simulated by the MC method and a scenario-based technique is applied to keep the trade-off between computation time and accuracy. The stochastic SCUC is used in which the scheduling horizon is decoupled into periodic stages (i.e., several weeks to one month) [17]. The periodic operation policy would determine, at the beginning of each period, how much water should be used or stored for the future use. The predefined operation rules are adopted to approximate the actual depletion policy of reservoirs located in a catchment, which would simplify the coupling constraints among successive periods and take advantage of the decomposition procedure. The problem is formulated as a two-stage stochastic programming model for the optimization period of one year, with the first stage optimizing the operation for the first month and the second stage for the remaining eleven months for simulating the midterm operation via scenarios. In this paper, SCUC would satisfy the hourly electricity and gas network constraints in the base case and all simulated scenarios. Reliability-based solution derived from the proposed two-stage model satisfies the hourly electricity and gas network security constraints and provides sufficient water and gas supply for minimizing the load shedding in the entire midterm horizon. Midterm period refers to the scheduling horizon of several months to one year, short-term refers to several hours to several weeks, and long-term covers several years.

The rest of the paper is organized as follows. Section 2 presents the solution methodology of the stochastic model. Section 3 presents and discusses a 6-bus system and a modified IEEE 118-bus system, and the conclusion is drawn in Section 4.

2 STOCHASTIC MIDTERM MODEL

The proposed stochastic optimization problem for analyzing the power system reliability and improving the operational efficiency of water and gas usages in a midterm horizon is formulated as a two-stage stochastic model. The objective, formulated in (1), is to minimize the social cost including operation cost (i.e., production cost, startup and shutdown costs of individual units) and the possible load shedding cost for the entire midterm horizon.

$$\begin{aligned}
& \min \sum_{p=1}^{NPD} \sum_{t=1}^{NT} \left\{ \sum_{i=1}^{NG} [F_c(P_{itp}) \cdot I_{itp} + SU_{itp} + SD_{itp}] \right\} + \\
& \left\{ \sum_{h=1}^{NH} SU_{htp} + \sum_{b=1}^{NB} \sum_{m=1}^{NM} p v_{b,m} \cdot LS_{btp,m} \right\} \quad (1) \\
& \sum_{s=1}^{NS} p^s \cdot \sum_{p=1+NPD}^{NPS+NPD} \sum_{t=1}^{NT} \left\{ \sum_{i=1}^{NG} [F_c(P_{itp}^s) \cdot I_{itp}^s + SU_{itp}^s + SD_{itp}^s] + \right. \\
& \left. \sum_{h=1}^{NH} SU_{htp}^s + \sum_{b=1}^{NB} \sum_{m=1}^{NM} p v_{b,m}^s \cdot LS_{btp,m}^s \right\}
\end{aligned}$$

The concept of utilizing scenarios adds another dimension to the solution that is different from that of the deterministic midterm UC planning model. The set of constraints includes:

- System power balance constraint.
- Individual generator constraints for various types of units, including ramping up/down rate limits, minimum on/off time limits, generation unit capacity limits, etc.
- Individual cascaded hydro unit constraints, including reserve volume limits, water balance constraint, water discharge limits, etc. We set the initial and the terminal volumes to be the same in a one year horizon to avoid excessive water usage. For the midterm hydro operation, the water usage in the current month is coordinated with that of future months in order to avoid excessive water use in the current month which could lead to the lack of sufficient water supply in future months.
- Power transmission constraints including dc network constraints and phase shifter angles limits.
- Natural gas transmission constraints including gas contract limits, gas usage limits, pipeline and compressor transmission capability limits, etc.
- Reliability constraints including load shedding limits at each bus and each time period in each scenario, and LOLE limits.
- Reservoir volume coupling constraints for two consecutive periods, which indicates that the terminal volume at the end of previous period should be the initial volume at the beginning of successive period.

Detailed formulations of constraints for the system and individual generators are found in [17], cascaded hydro system formulation in [18], reliability formulation in [15], and gas network formulation in [13]. The contributions of this paper reside in the formulation of midterm hydro reservoir operation, the optimization and the coordination of midterm water and natural gas usage, and the proposed solution methodology for the complex midterm scheduling problem by fully utilizing the capabilities of state-of-the-art mixed-integer programming, Lagrangian relaxation, and Benders decomposition techniques.

2.1 Scenario Techniques with MC

A set of scenarios is generated by MC for simulating power system uncertainties, including random outages of system components, electric and gas load forecast errors, and uncertainties associated with water inflows. The advantage of applying MC is that the simulation accuracy of MC depends on the number of samples rather than the dimension of uncertainty in each scenario. Therefore MC is suitable for power systems with large dimensions of uncertainty.

A two-state continuous-time Markov chain model is applied to simulate component outages in each scenario and UC states are calculated by solving the stochastic SCUC problem. The parameters used for MC are failure and repair rates of each power system component. The water inflow to a reservoir follows a discrete Markov chain, which is independent of inflows to other reservoirs, thus the spatially independent log-normal random variable correlated in time with a first-order lag is used to simulate the water inflow. The detailed formulations are provided in [17],[18]. The future power load and gas load uncertainty is represented by a truncated normal distribution with a probability density function shown in (2). The distribution is divided into a discrete number of intervals (i.e., μ , $\mu \pm \sigma$, $\mu \pm 2\sigma$, $\mu \pm 3\sigma$, etc) and the load in the mid-point of each interval represents the probability of the interval, where μ is the forecasted load and σ is the known standard deviation.

The Latin Hypercube Sampling (LHS) is developed to generate multi-dimensional random numbers to compose a set of scenarios. The scenario reduction can reduce the computational time by eliminating scenarios with very low probabilities and bundling scenarios that are very close in terms of statistical metrics [17]-[19].

$$f(x) = \begin{cases} 0 & x < \mu - 3.5\sigma \text{ or } x > \mu + 3.5\sigma \\ \frac{1}{\alpha \sqrt{2\pi}\sigma} \cdot e^{-\frac{(x-\mu)^2}{2\sigma^2}} & \mu - 3.5\sigma \leq x \leq \mu + 3.5\sigma \end{cases} \quad (2)$$

$$\text{where } \alpha = \int_{\mu-3.5\sigma}^{\mu+3.5\sigma} \frac{1}{\sqrt{2\pi}\sigma} \cdot e^{-\frac{(x-\mu)^2}{2\sigma^2}} dx$$

2.2 Midterm Reservoir Operation Rules

Simplified operation rules that approximate the depletion policy of cascaded reservoirs may be used to estimate the energy production [20]. The adopted operation rules define the volume of each reservoir v_h in a catchment as a function of γ_c corresponding to catchment c . That is, a set of curves is adopted for describing the relationship between the global parameter (one global parameter per catchment) and each reservoir volume in the catchment as

$$v_h = \Psi(\gamma_c) \quad \forall h \in c \quad (3)$$

The operation rule is given based on historical inflow records or nonlinear optimization model [21]. As shown in Figure 2, the operation rule does not have to represent a convex curve.

The following two formulations can be applied for MIP modeling of non-convex operation rule curves. Numbers of integer variables and constraints are often regarded as good indicators of computational difficulty of MIP models [23]. Considering a NV_h segments curve shown in Figure 2, Formulation 1 is based on the type 1 Special Ordered Set (SOS1), which forms variables within which only one is non-zero and would facilitate the branching process of branch-and-bound method for a faster convergence [22]-[23]. Different from Formulation 1 which introduces integer variables corresponding to each of NV_h segments, Formulation 2 includes integer variables corresponding to each of $NV_h - 1$ intermediate points, thus containing less integer variables than Formulation 1. The number of variables and constraints are listed in Table 1 for comparison. Although Formulation 1 introduces one more integer variable than Formulation 2, there would be NV_h nodes in either case by the branch-and-bound tree in the worst case. A MIP model is often easier to solve by expanding a limited number of constraints, which provides a tighter approximated MIP formulation and will be used in the tree search strategy. Based on our experience with different formulations for large systems, Formulation 2 is tighter and converges faster and used in this paper.

Figure 2 Depletion curves for a catchment

Table 1 Comparison of MIP formulations

	Formulation 1	Formulation 2
Number of Integer Variables	NV_h	$NV_h - 1$
Number of Total Variables	$2 \cdot NV_h + 2$	$2 \cdot NV_h + 1$
Number of Equality Constraints	3	2
Number of Inequality Constraints (limits of variables do not count in)	NV_h	$2 \cdot NV_h - 2$

Formulation 1:

$$\begin{aligned}
V_h &= V_{h,\min} \cdot \delta_{h,1} + \sum_{m=2}^{NV_h} V_{h,m-1} \cdot \delta_{h,m} + \sum_{m=1}^{NV_h} IC_{h,m} \cdot v_{h,m} \\
\gamma_c &= 0 \cdot \delta_{h,1} + \sum_{m=2}^{NV_h} \gamma_{h,m-1} \cdot \delta_{h,m} + \sum_{m=1}^{NV_h} v_{h,m} \\
\sum_{m=1}^{NV_h} \delta_{h,m} &= 1 \quad \delta_{h,m} \in \{0,1\} \\
0 \leq v_{h,1} &\leq (\gamma_{h,1} - 0) \cdot \delta_{h,1} \\
0 \leq v_{h,m} &\leq (\gamma_{h,m} - \gamma_{h,m-1}) \cdot \delta_{h,m} \quad m \in \{2, \dots, NV_h - 1\} \\
0 \leq v_{h,NV_h} &\leq (1 - \gamma_{h,NV_h-1}) \cdot \delta_{h,NV_h}
\end{aligned} \tag{4}$$

Formulation 2:

$$\begin{aligned}
V_h &= V_{h,\min} + \sum_{m=1}^{NV_h} IC_{h,m} \cdot v_{h,m} \\
\gamma_c &= 0 + \sum_{m=1}^{NV_h} v_{h,m} \\
(\gamma_{h,1} - 0) \cdot \delta_{h,1} &\leq v_{h,1} \leq (\gamma_{h,1} - 0) \\
(\gamma_{h,m} - \gamma_{h,m-1}) \cdot \delta_{h,m} &\leq v_{h,m} \leq (\gamma_{h,m} - \gamma_{h,m-1}) \cdot \delta_{h,m-1} \\
&\quad m \in [2, NV_h - 1] \\
0 \leq v_{h,NV_h} &\leq (1 - \gamma_{h,NV_h-1}) \cdot \delta_{h,NV_h-1} \\
\delta_{h,m} &\in \{0,1\}
\end{aligned} \tag{5}$$

2.3 Proposed Stochastic Solution

Scenarios add another dimension to the proposed solution of midterm model, which makes the proposed two-stage stochastic problem very large and computationally impractical. A proper decomposition procedure is necessary for decomposing the problem into tractable easy-to-solve subproblems for each period.

In order to consider midterm optimal water usage, reservoir volume coupling constraints between consecutive periods would need to be considered, which states that the terminal volume of one period would be the same as the initial volume of the next period. Thus, the midterm horizon is divided into several periods, with the relaxation of reservoir volume coupling limits for linking successive periods. Other coupling constraints, such as ramping up/down rate limits, minimum on/off time constraints and delayed water discharge from upper reservoirs to lowers, which link successive periods, are managed based on one of the following two strategies:

- 1) Constraints linking successive periods will be ignored. Accordingly, the short-term UC problem can be solved for each period independently. The application of parallel processing will speed up the solution. However, the accuracy may suffer slightly.
- 2) Short-term UC subproblems are solved sequentially. That is, the results of the short-term UC for the first period provide initial conditions for the second period. In this case, constraints linking successive periods will be satisfied within each period by UC.

The difference between the two alternatives signifies the tradeoff between speed and accuracy. In this paper, we adopt the second alternative. The reservoir volume which links successive periods is relaxed by introducing artificially duplicated variables of common variables in (6). In (6) the first constraint and third constraint correspond to the reservoir volume coupling constraint between successive periods at the first stage and second stage, respectively, and the second constraint is for the coupling constraint between the last period of the first stage and the first period of the second stage. Based on the midterm reservoir operation rule discussed earlier, (6) is substituted by (7) by using γ_c for each catchment c .

The introduction of global parameter γ_c , which uniformly adjusts reservoir volumes in a catchment, reduces the number of coupling constraints that are to be relaxed from $NH \cdot [(NPD - 1) + NS + NS \cdot (NPS - 1)]$ in (6) to $NC \cdot [(NPD - 1) + NS + NS \cdot (NPS - 1)]$ in (7). By introducing a set of Lagrangian multipliers, coupling constraints (7) are relaxed and the Lagrangian dual function of the original problem (1) is formulated as (8). (8) can be easily separated into tractable subproblems, (9)-(11), corresponding to periods at the first stage and (12)-(14) corresponding to periods of each scenario at the second-stage. A decomposition approach is used for solving each subproblem with respected to constraints discussed at the beginning of this Section 2.

$$\begin{aligned} V_{hNTp} &= V_{h0(p+1)} \quad \forall h, \forall p \in \{1, \dots, NPD - 1\} \\ V_{hNTp} &= V_{h0(p+1)}^s \quad \forall s, \forall h, p = NPD \end{aligned} \quad (6)$$

$$\begin{aligned} V_{hNTp}^s &= V_{h0(p+1)}^s \quad \forall s, \forall h, \forall p \in \left\{ \frac{NPD}{2} + 1, \dots, \frac{NPD}{2} + NPS - 1 \right\} \\ \gamma_{cNTp} &= \gamma_{c0(p+1)} \quad \forall c, \forall p \in \{1, \dots, NPD - 1\} \\ \gamma_{cNTp} &= \gamma_{c0(p+1)}^s \quad \forall s, \forall c, p = NPD \end{aligned} \quad (7)$$

$$\begin{aligned} L(\beta) = \min_{p=1}^{NPD} \sum_{t=1}^{NT} \left\{ \sum_{i=1}^{NG} [F_c(P_{itp}) \cdot I_{itp} + SU_{itp} + SD_{itp}] + \sum_{h=1}^{NH} SU_{htp} + \sum_{b=1}^{NB} \sum_{m=1}^{NM_b} pv_{b,m} \cdot LS_{btp,m} \right\} \\ + \sum_{s=1}^{NS} p^s \cdot \sum_{p=1+NPD}^{NPS+NPD} \sum_{t=1}^{NT} \left\{ \sum_{i=1}^{NG} [F_c(P_{itp}^s) \cdot I_{itp}^s + SU_{itp}^s + SD_{itp}^s] + \sum_{h=1}^{NH} SU_{htp}^s + \sum_{b=1}^{NB} \sum_{m=1}^{NM_b} pv_{b,m}^s \cdot LS_{btp,m}^s \right\} \end{aligned} \quad (8)$$

$$\begin{aligned} &+ \sum_{c=1}^{NC} \left\{ \sum_{p=1}^{NPD-1} \left(\gamma_{cNTp} - \gamma_{c0(p+1)} \right) + \sum_{s=1}^{NS} \beta_c^s \cdot \left(\gamma_{cNTNPD} - \gamma_{c0(NPD+1)} \right) + \right. \\ &\left. \sum_{s=1}^{NS} \sum_{p=1+NPD}^{NPS+NPD-1} \beta_{cp}^s \cdot \left(\gamma_{cNTp} - \gamma_{c0(p+1)} \right) \right\} \\ \min_{t=1}^{NT} &\left\{ \sum_{i=1}^{NG} [F_c(P_{it1}) \cdot I_{it1} + SU_{it1} + SD_{it1}] + \sum_{h=1}^{NH} SU_{ht1} + \sum_{b=1}^{NB} \sum_{m=1}^{NM_b} pv_{b,m} \cdot LS_{btp,m} \right\} + \sum_{c=1}^{NC} \beta_{c1} \cdot \gamma_{cNT1} \end{aligned} \quad (9)$$

$$\begin{aligned} \min_{t=1}^{NT} &\left\{ \sum_{i=1}^{NG} [F_c(P_{itp}) \cdot I_{itp} + SU_{itp} + SD_{itp}] + \sum_{h=1}^{NH} SU_{htp} + \sum_{b=1}^{NB} \sum_{m=1}^{NM_b} pv_{b,m} \cdot LS_{btp,m} \right\} + \sum_{c=1}^{NC} \left\{ \beta_{cp} \cdot \gamma_{cNTp} - \beta_{c(p-1)} \cdot \gamma_{c0p} \right\} \\ &\forall p \in \{2, \dots, NPD - 1\} \end{aligned} \quad (10)$$

The approach applies BD for separating UC in the master problem from the dc network and the gas network security check in subproblems. Successive linear programming is applied to solve the gas transmission feasibility check. If any electric power network or gas network violations arise, corresponding Benders cuts are formed and added to the master problem for solving the next iteration [13].

$$\min_{t=1}^{NT} \left\{ \sum_{i=1}^{NG} [F_c(P_{itp}) \cdot I_{itp} + SU_{itp} + SD_{itp}] + \sum_{h=1}^{NH} SU_{htp} + \sum_{b=1}^{NB} \sum_{m=1}^{NM_b} pv_{b,m} \cdot LS_{btp,m} \right\} + \sum_{c=1}^{NC} \left\{ \sum_{s=1}^{NS} \beta_c^s \cdot \gamma_{cNTp} - \beta_{c(p-1)} \cdot \gamma_{c0p} \right\} \quad p = NPD \quad (11)$$

$$\min_{t=1}^{NT} p^s \cdot \left\{ \sum_{i=1}^{NG} [F_c(P_{itp}^s) \cdot I_{itp}^s + SU_{itp}^s + SD_{itp}^s] + \sum_{h=1}^{NH} SU_{htp}^s + \sum_{b=1}^{NB} \sum_{m=1}^{NM_b} pv_{b,m}^s \cdot LS_{btp,m}^s \right\} + \sum_{c=1}^{NC} \left\{ \beta_{cp}^s \cdot \gamma_{cNTp} - \beta_{c(p-1)}^s \cdot \gamma_{c0p}^s \right\} \quad p = NPD + 1 \quad (12)$$

$$\begin{aligned} \min_{t=1}^{NT} p^s \cdot \left\{ \sum_{i=1}^{NG} [F_c(P_{it1}^s) \cdot I_{it1}^s + SU_{it1}^s + SD_{it1}^s] + \sum_{h=1}^{NH} SU_{ht1}^s + \sum_{b=1}^{NB} \sum_{m=1}^{NM_b} pv_{b,m}^s \cdot LS_{btp,m}^s \right\} + \sum_{c=1}^{NC} \left\{ \beta_{cp}^s \cdot \gamma_{cNTp} - \beta_{c(p-1)}^s \cdot \gamma_{c0p}^s \right\} \\ \forall p \in \{NPD + 2, \dots, NPD + NPS - 1\} \end{aligned} \quad (13)$$

$$\min_{t=1}^{NT} p^s \cdot \left\{ \sum_{i=1}^{NG} [F_c(P_{itp}^s) \cdot I_{itp}^s + SU_{itp}^s + SD_{itp}^s] + \sum_{h=1}^{NH} SU_{htp}^s + \sum_{b=1}^{NB} \sum_{m=1}^{NM_b} pv_{b,m}^s \cdot LS_{btp,m}^s \right\} - \sum_{c=1}^{NC} \beta_{c(p-1)}^s \cdot \gamma_{c0p}^s \quad p = NPD + NPS \quad (14)$$

Since Lagrangian dual function is non-differentiable, the standard subgradient method would result in a slow convergence. A proximal Bundle method is used, which diminishes the unstable behavior of cutting-plane algorithm and speeds up the convergence process by adding the trust region philosophy [24],[25].

First $\bar{\beta} = \{\bar{\beta}_{cp}, \bar{\beta}_c^s, \bar{\beta}_{cp}^s\}$ is selected among the current set of available solutions, which is typically the one that provides the largest $L(\beta)$. The quadratic problem (15) is solved to find $\beta^k = \{\beta_{cp}^k, \beta_c^{k,s}, \beta_{cp}^{k,s}\}$ for the next iteration, where Δ^j is the linearization error. Here, $\|\cdot\|$ is the Euclidean norm and α^k is an iteration-variant positive parameter, called the trust-region parameter, which decides the region that can be trusted as an approximation for $L(\beta)$.

Several issues are discussed here for an efficient bundle algorithm, including the dynamic choice of parameter α^k , updating strategy for the current point $\bar{\beta}$, and stopping criterion. At each iteration, k , the current point $\bar{\beta}$ will be shifted to β^k only if (16) is satisfied, and α^k for the next iteration will be increased to enlarge the trust region if (17) is not satisfied.

Otherwise, the current solution of iteration k is added to the bundle if Δ^k is small compared with a predefined threshold. If the condition is not satisfied, we discard the solution of this iteration and reduce α^k to shrink the trust region for solving (15) again. The α^k updating strategy is as follows:

- Predefine lower and upper bounds of α , α_{Min} and α_{Max} as $\alpha^0 = (\alpha_{Min}^0 + \alpha_{Max}^0)/2$, $\alpha_{Min}^0 = \alpha_{Min}$, $\alpha_{Max}^0 = \alpha_{Max}$.
- For each iteration k , set $\alpha_{Min}^k = \alpha^{k-1}$ if α^k is to be increased; otherwise set $\alpha_{Max}^k = \alpha^{k-1}$ and the new α^k will be calculated as $\alpha^k = (\alpha_{Min}^k + \alpha_{Max}^k)/2$.

$$\max_{\beta_{cp}^k, \beta_c^{k,s}, \beta_{cp}^{k,s}} \left\{ EV^k - \frac{1}{2 \cdot \alpha^k} \|\beta^k - \bar{\beta}\|^2 \right\} \quad s.t. \quad \left\{ \begin{aligned} & \sum_{p=1}^{NPD-1} (\beta_{cp} - \bar{\beta}_{cp}) \cdot (\gamma_{cNTp}^j - \gamma_{c0(p+1)}^j) + \\ & \sum_{c=1}^{NC} \left\{ \sum_{s=1}^{NS} (\beta_c^s - \bar{\beta}_c^s) \cdot (\gamma_{cNTNPD}^j - \gamma_{c0(NPD+1)}^{j,s}) + \right. \\ & \left. \sum_{s=1}^{NS} \sum_{p=1+NPD}^{NPS+NPD-1} (\beta_{cp}^s - \bar{\beta}_{cp}^s) \cdot (\gamma_{cNTp}^{j,s} - \gamma_{c0(p+1)}^{j,s}) \right\} \end{aligned} \right\} \quad (15)$$

$$\Delta^j = L(\beta^j) - L(\bar{\beta}) + \left\{ \begin{aligned} & \sum_{p=1}^{NPD-1} (\bar{\beta}_{cp} - \beta_{cp}^j) \cdot (\gamma_{cNTp}^j - \gamma_{c0(p+1)}^j) + \\ & \sum_{c=1}^{NC} \left\{ \sum_{s=1}^{NS} (\bar{\beta}_c^s - \beta_c^{j,s}) \cdot (\gamma_{cNTNPD}^j - \gamma_{c0(NPD+1)}^{j,s}) + \right. \\ & \left. \sum_{s=1}^{NS} \sum_{p=1+NPD}^{NPS+NPD-1} (\bar{\beta}_{cp}^s - \beta_{cp}^{j,s}) \cdot (\gamma_{cNTp}^{j,s} - \gamma_{c0(p+1)}^{j,s}) \right\} \end{aligned} \right\}$$

$$[L(\beta^k) - L(\bar{\beta})] / L(\bar{\beta}) \geq \varepsilon_1 \quad (16)$$

$$\sum_{c=1}^{NC} \left\{ \sum_{s=1}^{NS} (\beta_c^{k,s} - \bar{\beta}_c^s) \cdot (\gamma_{cNTNPD}^k - \gamma_{c0(1+NPD)}^{k,s}) + \sum_{s=1}^{NS} \sum_{p=1+NPD}^{NPS+NPD-1} (\beta_{cp}^{k,s} - \bar{\beta}_{cp}^s) \cdot (\gamma_{cNTp}^{k,s} - \gamma_{c0(p+1)}^{k,s}) \right\} \leq \varepsilon_2 \quad (17)$$

The process stops when the Lagrangian multiplier difference between two successive iterations is smaller than the predefined threshold ε_3 in (18). The solution that satisfies the stopping criterion may not satisfy the relaxed constraints (6)-(7). (19) calculates the degree of violation of relaxed constraints (6)-(7). A feasible solution is constructed by heuristically adjusting the initial and terminal reservoir volumes at each period based on the system

load at successive periods (20)-(22), which are calculated and used as limits for the problem optimization at the final run. Because ΔV is small when the stopping criterion is met, and reservoirs have spillage capability, the final run will not encounter infeasibility by minor adjustments of reservoir volumes (20)-(22).

$$\|\beta^k - \bar{\beta}\|^2 = \sum_{c=1}^{NC} \left\{ \sum_{p=1}^{NPD-1} (\beta_{cp}^k - \bar{\beta}_{cp})^2 + \sum_{s=1}^{NS} (\beta_c^{k,s} - \bar{\beta}_c^s)^2 + \sum_{s=1}^{NS} \sum_{p=1+NPD}^{NPS+NPD-1} (\beta_{cp}^{k,s} - \bar{\beta}_{cp}^s)^2 \right\} \leq \varepsilon_3 \quad (18)$$

$$\Delta V = \sqrt{\sum_{h=1}^{NH} \left\{ \sum_{p=1}^{NPD-1} (V_{hNTp}^k - V_{h0(p+1)})^2 + \sum_{s=1}^{NS} (V_{hNTNP}^s - V_{h0(1+NPD)}^s)^2 \right\} + \sum_{s=1}^{NS} \sum_{p=1+NPD}^{NPS+NPD-1} (V_{hNTp}^s - V_{h0(p+1)}^s)^2} \quad (19)$$

$$V_{hNTp}^F = V_{h0(p+1)}^F = V_{hNTp}^k + (V_{h0(p+1)}^k - V_{hNTp}^k) \cdot \frac{\sum_t PL_{tp}}{\sum_t PL_{tp} + \sum_t PL_{t(p+1)}} \quad \forall p \in \{1, \dots, NPD-1\} \quad (20)$$

$$V_{hNTp}^F = V_{h0(p+1)}^F = V_{hNTp}^k + \left(\sum_s p^s \cdot V_{h0(p+1)}^{k,s} - V_{hNTp}^k \right) \cdot \frac{\sum_t PL_{tp}}{\sum_t PL_{tp} + \sum_s p^s \cdot \left(\sum_t PL_{t(p+1)}^s \right)} \quad p = NPD \quad (21)$$

$$V_{hNTp}^{F,s} = V_{h0(p+1)}^{F,s} = V_{hNTp}^{k,s} + (V_{h0(p+1)}^{k,s} - V_{hNTp}^{k,s}) \cdot \frac{\sum_t PL_{tp}^s}{\sum_t PL_{tp}^s + \sum_t PL_{t(p+1)}^s} \quad \forall p \in \left\{ \frac{NPD}{NPD+NPS-1}, \dots, \frac{NPD}{NPD+NPS-1} \right\} \quad (22)$$

Figure 3 shows the solution strategy for decomposing the large-scale problem into tractable easy-to-solve subproblems. With the relaxation of reservoir volume coupling constraints by introducing Lagrangian multipliers, the midterm problem is divided into several short-term subproblems, corresponding to the period in the first stage and d periods in the second stage for each scenario. For each short-term SCUC subproblem, Benders decomposition is applied for separating UC in the master problem from the hourly dc network and gas network evaluation in subproblems. If any electric power network or gas network violations arise, corresponding Benders cuts are formed and added to the master problem for solving the next iteration [13]. After obtaining the hydro schedules from the short-term operation subproblems, the coupling constraints of reservoir volume are checked. If the constraints are violated, the corresponding Lagrangian multipliers are updated. The Lagrangian iterations will continue until a near optimal solution is reached, and the final feasible solution is constructed by heuristically adjusting the initial and terminal reservoir volumes at each period.

Figure 3 Optimization and coordination for the midterm operation planning with optimal usage for water and natural gas

3 CASE STUDY

A 6-bus system and the IEEE 118-bus system are considered to demonstrate the proposed approach for the optimal scheduling of midterm water and gas usages.

3.1. 6-bus system

The 6-bus system in Figure 4 is used to illustrate the proposed method. The system has three gas-fired units, one hydro unit and seven transmission lines. The hydro unit data are shown in Table 2. Other detailed generator, transmission line and gas network data are given in [13]. Failure and repair rates for transmission lines are 0.0671 failures/year and 0.9329 repairs/year.

Failure and repair rates for generating units are listed in Table 3. The system is tested for a one-year case (from November to the following October) with the annual peak power load of 330MW and annual peak gas load of 6,000 kcf. Figure 5 shows the weekly peak loads as a percentage of annual peak load. The maximum allowable load shedding is set to be the load value at the designated bus, with a VOLL of 5,000\$/MWh for the first 10 percent of the load and 2,000\$/MWh for the remaining. For the 6-bus system, each period refers to a month. Thus, the first stage contains one period and the second stage contains eleven periods in each scenario.

Figure 4 One-line diagram of six-bus example

Table 2 Parameters of hydro unit

Efficiency	h0	α	Discharge Max ($\times 10^4 \text{ m}^3$)	Discharge Min ($\times 10^4 \text{ m}^3$)
8.091	0.857	0.0001315	10	1
Pmin (MW)	Pmax (MW)	Ramp (MW/h)	Min On(h)	Min Off (h)
9	80	60	1	1
Volume Min ($\times 10^4 \text{ m}^3$)	Volume Max ($\times 10^4 \text{ m}^3$)	Initial Volume ($\times 10^4 \text{ m}^3$)	Terminal Volume ($\times 10^4 \text{ m}^3$)	Initial hour
60	1000	1000	1000	1
Operation Rule				
Global Parameter	0	0.25	0.75	1
Volume ($\times 10^4 \text{ m}^3$)	60	250	800	1000

Table 3 Failure and repair rates of generators

Units	NG1	NG2	NG3	H1
Failure Rate (failures/year)	0.0307	0.0286	0.0259	0.0262
Repair Rate (repairs/year)	2.4444	2.2749	2.0622	2.0893

Figure 5 Weekly peak loads as a percentage of annually peak load

Two cases are studied to illustrate the effect of midterm water and gas optimal usages on power system reliability:

Case 1: A deterministic solution in the winter season is presented and its impact on the system reliability is discussed, where forced outage rates are assumed to be negligible and the power and gas loads given in Figure 5 are used. The uncertainty of water inflow is not considered, thus the terminal reservoir volume is not restricted. The optimization of deterministic model utilizes as much water as possible to supplement the gas usage in the winter season (November-January with highest gas loads). The impact of the deterministic solution on the system reliability is considered by optimizing a scenario-based stochastic model for the remaining months of

February-October by utilizing terminal volumes at the end of January as the initial condition.

The computation time for the scenario-based problem depends on the number of scenarios. The scenario reduction method would reduce the total number of scenarios from 100 to 12 as a tradeoff between calculation speed and solution accuracy. Table 4 shows the weights of each scenario after reduction. The results of the first three months in Case 1 are presented in Table 5.

Table 4 Weights of each scenario after scenario reduction

Scenario	1	2	3	4	5	6
Weight	0.07	0.075	0.18	0.035	0.065	0.24
Scenario	7	8	9	10	11	12
Weight	0.07	0.045	0.045	0.01	0.04	0.125

Table 5 Results for the first 3 months in Case 1

Social Cost (\$)	12,141,356.75	
LS (MWh)	411.42	
# of Hours LS Occurs	56	
Volume at the end of each month (*10 ⁴ m ³)	11	860.34
	12	65.83
	1	60.00

Due to the limited capability of gas network, the gas required by gas-fired generating units cannot be transported to corresponding nodes by the gas transmission system. The water resource is the alternative energy to cover the load. It is shown that most of the water reservoir is used in December because of the highest demand by gas loads shown in Figure 5. The terminal reservoir volume at the end of winter reaches its minimum value of $60 \times 10^4 \text{ m}^3$ because the terminal reservoir volume is not restricted and the water resource in the reservoir is used as much as possible. We use the terminal volume at the end of winter, as the initial condition for the following seasons, and $1000 \times 10^4 \text{ m}^3$ as the terminal volume for the remaining 9 months. The resulting social cost and load shedding for each scenario is listed in Table 6. Based on results presented in Tables 6 and 7, the social cost is \$39,585,164.34 (i.e. $12,141,356.75 + 27,443,807.59$) with a load shedding of 460.91MWh. The annual load shedding is 96.465 hours.

Table 6 Results for the following seasons based on Case 1

Scenario	Social Cost (\$)	LS (MWh)	# of LS Hours
1	27,659,311.07	53.62	57
2	27,425,028.63	37.29	35
3	27,678,604.15	53.10	39
4	27,551,233.52	54.52	43
5	27,296,860.88	38.91	47
6	27,672,777.70	43.15	29
7	27,608,847.21	57.60	48
8	28,646,885.12	45.15	40
9	26,587,588.48	43.03	33
10	28,715,483.62	76.87	54
11	27,667,616.62	57.55	50
12	26,212,352.22	60.16	49
Expected	27,443,807.59	49.49	40.465

Case 2: The proposed two-stage stochastic optimization model is discussed. The first-stage covers the first month and the second-stage includes the remaining 11 months via scenarios. The uncertainties of system component availability, power and gas load levels, and water inflows are considered. Table 7 shows that by the midterm stochastic optimization of water and gas usages, one can optimally allocate the water resource to enhance the system reliability. In comparison with Case 1, load shedding is reduced from 460.91MWh to 440.90 MWh. The annual load shedding is reduced from 96.465 hours to 71.07 hours. The reservoir water, previously utilized fully in Case 1, is now partly allocated to the summer for peak-shaving. The social cost in comparison to Case 1 is reduced by 5.08% (i.e., $39,585,164.34 - 37,572,145.9 / 39,585,164.34$.)

For this Case, the period for the first-stage and periods corresponding to each scenario in the second-stage are solved sequentially. The CPU time consumed for one scenario is about 15 minutes, and about 60 hours (i.e., No. of scenarios * No. of iterations * 15 minutes) for the entire two-stage stochastic programming on a 3.2 GHz Pentium 4 personal computer. However, parallel computing applied to scenarios would rapidly reduce the CPU time to 5 hours.

Figure 6 shows the optimal monthly water resource allocations for Case 1 and two scenarios of Case 2, representing a wet and a dry weather. In Case 1, the reservoir water is used fully when the future water inflow situation is not considered. Two scenarios, a dry and a wet year, presented in Figure 6 show that when the uncertainty of water inflow is considered, the water used in winter would have to be limited in order to cover the summer peaks. Figure 6 shows that reservoir volumes for wet and dry scenarios are decreased in June since the water is discharged for peak load shaving. That is, the terminal volumes at the end of January are higher than that of Case 1 to cover a possible dry summer season. Figure 6 shows that for the dry scenario, the water usage in November through January is strictly limited with the limited reservoir refilling. This is due to the less available water resource in January through April. The results reveal the necessity of incorporating a two-stage stochastic optimization model for the midterm water and gas management to enhance the system reliability.

Table 7 Results for Case 2

First-stage solution			
Social Cost		3,473,861.69	
LS (MWh)		0	
# of LS Hours		0	
Terminal Volume (*10 ⁴ m ³)		984.29	
Second-stage solution			
Scenario	Social Cost (\$)	LS (MWh)	# of LS Hours
1	34,234,442.97	426.7466	82
2	33,745,037.61	447.1278	58
3	34,337,516.25	436.0846	63
4	33,707,806.17	426.1430	66
5	33,513,715.31	422.8795	72
6	33,985,407.29	446.8944	64
7	34,046,856.81	452.2434	69
8	35,486,860.11	432.0145	79
9	33,888,175.90	423.6509	71
10	36,731,962.03	444.9300	94
11	33,916,433.81	452.5987	88
12	33,971,571.38	452.9742	90
Expected	34,098,284.21	440.9000	71.07

Figure 6 Terminal volumes at the end of each month

In order to demonstrate the convergence process, Figure 7 presents the iterative Lagrangian function. After 20 iterations, we found a solution of \$12,081,574.76 which satisfies the stopping criterion (18). By applying the heuristic adjustments (20)-(22), the final social cost is \$12,141,356.75. Figure 7 shows the better performance of bundle method in comparison with that of the subgradient method. Figure 8 shows the degree of constraints violation as calculated in (19). The violation in bundle method is reduced much faster than that in the subgradient method, implying that the feasibility is further improved. A better schedule is obtained, which needs less modification in the heuristics process for deriving a final feasible solution.

Figure 7 Iterative values of $L(\beta)$ in Case 1

Figure 8 Iterative values of reservoir coupling violation in Case 1

3.2. IEEE 118-bus system

A modified IEEE 118-bus system is studied with 54 fossil units, 12 gas-fired units, 7 hydro units, 186 branches, and 91 demand sides. The peak load is 8,600 MW. Hydro units 1-4 belong to one catchment and units 5-7 belong to the second catchment. Detailed generator, transmission line and gas network data are found in [13],[17]. For the 118-bus system, since it is impossible to run a monthly SCUC at one shot, each period refers to a time span of one week. Thus, the first stage contains four periods and the second stage contains remaining 48 periods in each scenario. The probability of each scenario is shown in Table 8. The same two cases in the 6-bus system are considered again. Tables 9-10 present the solution of Case 1 with a social cost of \$167,505,857.79 for the winter season. Without considering the water inflow uncertainty, terminal reservoir volumes are limited to their corresponding minimum values. Adopting these terminal volumes as initial conditions for the following seasons, the future social cost is \$498,438,128.63 with the load shedding of 10,220.87 MWh. Table 11 shows the optimal two-stage stochastic solution with uncertainties. The load shedding is reduced from 16,036.86 MWh to 14,988.16 (i.e., 1,641.65+13,346.51) MWh. The optimal allocation of water reservoirs for the midterm horizon reduces the social cost by 2.83% (i.e., $((498,438,128.63 + 167,505,857.79) - (54,915,796.54 + 592,150,917.73)) / (498,438,128.63 + 167,505,857.79)$) which shows that by considering uncertainties in the optimization of water and gas usages in a midterm horizon, one can optimally allocate water resource to enhance the system reliability.

Table 8 Weight of each scenario after scenario reduction

Scenario	1	2	3	4	5	6
Weight	0.05	0.075	0.125	0.07	0.09	0.185
Scenario	7	8	9	10	11	12
Weight	0.065	0.07	0.06	0.05	0.05	0.11

Table 9 Results for the first 3 months of Case 1

Social Cost (\$)		167,505,857.79
Load Shedding (MWh)		5,815.99
Volume at the end of each month (*10 ⁴ m ³)	Hydro Unit 1	11 789.521400
		12 100.576885
		1 70
	Hydro Unit 5	11 814.661521
		12 110.595936
		1 60

Table 10 Results in the following seasons based on results of Case 1

Scenario	Social Cost (\$)	LS (MWh)	Scenario	Social Cost (\$)	LS (MWh)
1	469,781,501.38	9,623.66	7	551,316,220.46	8,995.90

2	546,776,969.21	12,474.30	8	444,484,699.84	9,254.63
3	475,292,113.82	9,213.25	9	449,050,768.81	10,892.67
4	482,963,151.36	10,474.21	10	472,859,825.43	10,474.37
5	480,598,672.06	9,264.79	11	579,381,075.70	8,973.25
6	555,092,475.68	11,376.21	12	438,829,845.99	10,203.03
Expected Cost		498,438,128.63	Expected LS		10,220.87

Table 11 Results of Case 2

First-stage solution (November)					
Social Cost			\$54,915,796.54		
LS (MWh)			1,641.65		
Terminal Volume (*10 ⁴ m ³)			Hydro Unit 1		Hydro Unit 5
			443.985		524.97
Second-stage solution (December – October)					
Scen	Social Cost (\$)	LS (MWh)	Scen	Social Cost (\$)	LS (MWh)
1	569,348,058.64	12,709.49	7	638,250,719.88	12,140.42
2	631,623,855.91	15,675.10	8	553,314,423.24	12,541.41
3	575,609,207.51	12,374.16	9	548,171,522.09	14,049.00
4	573,665,664.86	13,381.57	10	579,617,496.76	13,207.50
5	571,984,423.07	12,647.78	11	659,318,818.53	12,121.87
6	639,399,045.85	14,535.15	12	539,828,573.25	13,165.35
Expected Cost		592,150,917.73	Expected LS		13,346.51

4 CONCLUSIONS

This paper proposed a two-stage stochastic programming model for the optimization of midterm water and gas usage with uncertainties. The probabilistic reliability criteria, which are measured by the expected load shedding quantity and number of hours that load shedding happens, are incorporated into the midterm stochastic UC problem, in which both the power and the gas network security constraints are checked. The optimal mid-term water usage allocation is achieved by introducing reservoir operation rules with a global operation parameter for the whole catchment. The optimal operating point is based on the minimum social cost which includes operating and load shedding costs. The contributions of this work resides in the formulation of midterm hydro reservoir operation, the optimization and coordination for the midterm water and natural gas usages, and the proposed solution methodology for the complex midterm scheduling problem by fully utilizing the capabilities of state-of-the-art mixed-integer programming, Lagrangian relaxation, and Benders decomposition techniques. The optimal point is influenced by the unavailability of power system components, power and gas load levels, and water inflows, which are accurately simulated via multiple scenarios by the Monte Carlo method. The results reveal that water management policies have a major impact on the system reliability. The system reliability is significantly improved by efficiently adjusting the water usage in a midterm horizon. In this regard, the water usage is optimally distributed throughout the midterm horizon. The study shows that the proposed two-stage stochastic optimization model can improve the power system reliability and decrease the social cost by optimally allocating water and gas usages in a midterm horizon.

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Coordinated scheduling of electricity and natural gas infrastructures with a transient model for natural gas flow

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This paper focuses on transient characteristics of natural gas flow in the coordinated scheduling of security-constrained electricity and natural gas infrastructures. The paper takes into account the slow transient process in the natural gas transmission systems. Considering their transient characteristics, natural gas transmission systems are modeled as a set of partial differential equations (PDEs) and algebraic equations. An implicit finite difference method is applied to approximate PDEs by difference equations. The coordinated scheduling of electricity and natural gas systems is described as a bi-level programming formulation from the independent system operator's viewpoint. The objective of the upper-level problem is to minimize the operating cost of electric power systems while the natural gas scheduling optimization problem is nested within the lower-level problem. Numerical examples are presented to verify the effectiveness of the proposed solution and to compare the solutions for steady-state and transient models of natural gas transmission systems. © 2011 American Institute of Physics. [doi:10.1063/1.3600761]

The electricity and natural gas infrastructures are highly intertwined¹⁻⁶ today as more and more gas-fired units have been introduced into power systems and installed, along with an increasing number of high-pressure natural gas pipelines. The security and economics of coupled infrastructures are interdependent.¹⁻³ Using purely topological metrics to analyze their interdependency can lead to misleading results.⁴ Cascaded failures of energy systems may be due to a variety of reasons. One of the most important causes is inaccurate scheduling and decision making so that the system cannot handle variations of loads and severe disturbances. The security-constrained, coordinated scheduling of two coupled energy systems is critical to mitigating the hidden security risks of energy systems, to preventing cascaded failures, and to realizing savings in their operating costs. However, natural gas and electric power flows usually travel through networks via different speeds and illustrate distinct physical characteristics. Hence, we model the electric power and natural gas systems differently but in a coupled manner. The numerical results show that the steady-state natural gas flow model would neglect the built-in storage capabilities of pipelines and the slower travelling speeds of natural gas flows, which may result in impractical or suboptimal schedules in the short-term coordinated scheduling of electricity and natural gas infrastructures.

I. INTRODUCTION

The adequacy and availability of natural gas fuel will directly affect the generation unit commitment (UC), dispatch, operating costs, as well as reliability of electric power systems.^{5,6} The electric power system is special in the sense that real-time balance between generation and load is required under both normal and fault condition. When contingencies occur, the operators can call gas-fired units that can respond quickly to address the imbalances in comparison with slow-start coal-fired and nuclear units. If the imbalances between generation and load are not eliminated immediately, the frequency of the power system will increase or decrease, which may lead to the loss of stability of the system through electromechanical and electromagnetic transients. More importantly, voltage collapses and loss of synchronization of more generators will increase the likelihood of a blackout. Therefore, adequacy of natural gas fuel is very critical to ensure the power system reliability and to prevent the cascaded failure of power systems.

However, in most cases, gas-fired generating units hold interruptible transportation contracts that would treat the units as preferential curtailment candidates. The natural gas drawn by gas-fired generating units with interruptible transportation contracts would be limited or curtailed once the congestion in natural gas transmission systems has occurred or gas wells have reached their maximum discharge. Moreover, the operation of new gas turbine units or combined-cycle gas turbine units would usually depend on high gas pressure. Hence, electric generators are more susceptible to pressure drops than are other natural gas loads.⁷ Even if the priority of natural gas delivery for gas-fired generating units was the same as that of other natural gas loads, the weaker

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ability of gas-fired generating units to manage pressure drops would make the natural gas curtailment more evident.

Many networks, such as energy, biology, and social relationship, are multi-layer interdependent networks. The loss of a part of links and nodes in one network may lead to a forced outage in another network.² The failure of components in the second network in turn may lead to a malfunction of additional nodes in the first network. Eventually, the interdependent networks may lose their functions completely. Similarly, any disruption in natural gas supply could have a significant impact on several gas-fired power plants and results in more critical outages than traditional contingencies in power systems. Outages of several gas-fired generators can result in the loss of operating reserves, real-time imbalances between load and generation, and an adverse effect on the system frequency. If necessary, operators would have to adopt load shedding to prevent any collapse in electric power system operations. References 5 and 10 offer examples of preliminary results on the impact of pipeline contingencies on power systems. Moreover, compressors, control devices, and other facilities in natural gas transmission systems are dependent on electricity. Load shedding or interruption of electricity may in turn lead to the failure of a fraction of natural gas system.

In order to satisfy the requirements of gas-fired generating units and other natural gas loads within a reasonable pressure range,^{7,8} the natural gas transmission system would have to schedule gas wells and compressors in advance and manage line-pack resources. “Line pack” is related to the amount of additional natural gas stored in a pipeline as a result of maintaining above-normal pressure in the pipeline.^{7,9} As such, line pack is analogous to reserves in power systems and is essential in enabling pipelines to handle large swings in natural gas loads, such as the fast ramp up of gas-fired generating units during peak hours and power system contingencies.

In the last ten years, several articles proposed state-of-the-art strategies to model the two interdependent infrastructures.^{10–14} However, many of the previous studies focused on the steady-state formulation of electric power and natural gas transmission systems. Such formulations neglected a significant distinction to be made in the traveling speeds of natural gas and electric power flows, as well as the line-pack capacities of interstate pipelines.

This paper concentrates on the development of a methodology for the coordinated scheduling of interdependent power and natural gas transmission systems that are based on a transient-state model of natural gas flows. The paper focuses on slow transient processes—that is, in terms of hours or minutes—caused by natural gas load swings. In the proposed formulation, interstate natural gas pipelines are described by a set of partial differential equations (PDEs) instead of by steady-state Weymouth equations. The implicit finite difference method is adopted to approximate PDEs with algebraic difference equations. As a result, natural gas flows are coupled in space and time. The paper presents a bi-level model shown in Fig. 1 for coordination between natural gas operators and the independent system operator (ISO). Constraints on natural gas supply contracts are directly

FIG. 1. Coordination scheme for electric power and natural gas infrastructures.

included in the UC problem. When an optimal UC schedule is obtained without violating power transmission constraints, the hourly natural gas demands of gas-fired generating units will be submitted to natural gas system operators, in the lower-level problem, for checking the feasibility of natural gas transmission constraints. If any violations are detected in natural gas transmission constraints, corresponding energy constraints (Benders-like cuts) are formed and fed back to the ISO for the next iteration of the coordination problem. The cut, which represents shortages in the natural gas supply or congestion in the gas transmission system, would limit the fuel consumed by gas-fired generating units. If the natural gas transmission check is feasible, the natural gas consumed by gas-fired generating units, as well as the security-constrained unit commitment (SCUC) solution, are final. The natural gas transmission operator will schedule compressors by minimizing rates of energy consumption.

The rest of the paper is organized as follows. Section II proposes the transient-state model of natural gas transmission systems. Section III presents formulations of the coordinated scheduling model. Algorithms for solving the proposed model are discussed in Sec. IV. Numerical studies are given in Sec. V. The conclusion is drawn in Sec. VI.

II. TRANSIENT FLOWS IN NATURAL GAS SYSTEMS

The dynamics of energy infrastructures could vary from milliseconds to hours, which indicates that energy transportation could occur in different frameworks. Electric energy travels almost instantaneously and cannot be stored economically in large quantities in current power systems. At the operation planning stage, once power injections and withdrawals at various buses are given, transmission line flows will satisfy steady-state algebraic equations that are independent on an hourly basis. Therefore, SCUC and security-constrained economic dispatch (SCED) commonly ignore

transients in the electricity infrastructure and focus on steady-state analyses.^{15–17}

The natural gas pipeline flow would represent a much slower process. Such pipelines take longer to respond to disturbances. In particular, high-pressure interstate pipelines have much slower dynamics, and large sums of natural gas stored in the pipelines cannot be neglected. In this case, the steady-state assumption and the corresponding algebraic Weymouth equation for pipelines might be inappropriate for the numerical calculation of natural gas flows. If treated rigorously, natural gas flow simulations would require distributed parameters and the transient state model of pipelines.^{18–23}

A. Modeling of natural gas pipelines

Natural gas flows, driven by pressure through pipelines, are dependent on factors such as the length and the diameter of pipelines, operating temperature, composition of natural gas, altitude change over the transmission path, roughness of pipelines, and boundary conditions. The transient state of natural gas flow through a pipeline is described as a one-dimensional dynamics along the axis of the natural gas pipeline, which requires the use of distributed parameters and time-varying state variables. A set of PDEs is obtained by applying the laws of conservation of mass and energy, the laws of momentum. The PDEs for time and position, which are dependent natural gas density, mass flow, flow velocity, and pressure, are given in Eqs. (1)–(4)

$$\frac{\partial(\rho \cdot v)}{\partial z} = -\frac{\partial \rho}{\partial t}, \quad (1)$$

$$\frac{\partial(\pi + \rho \cdot v^2)}{\partial z} + \frac{2f_c \cdot \rho \cdot v^2}{d} + \frac{\partial(\rho \cdot v)}{\partial t} + \rho \cdot g_e \cdot \sin \alpha = 0, \quad (2)$$

$$\frac{\partial[\rho \cdot (e + \frac{1}{2}v^2)]}{\partial t} + \frac{\partial[\rho \cdot v \cdot (h + \frac{1}{2}v^2)]}{\partial z} - \rho \cdot \Omega + \rho \cdot g_e \cdot v \cdot \sin \alpha = 0, \quad (3)$$

$$\pi = \rho \cdot Z \cdot R_g \cdot T, \quad (4)$$

where t represents time in the scheduling period; ρ represents natural gas density; π here denotes natural gas pressure; v denotes natural gas axial velocity; h denotes specific enthalpy; z represents the length scale of the pipeline; e denotes a specific internal energy of the gas pipeline; Ω represents the rate of heat transfer per unit time and unit mass of the gas; Z represents a compressibility factor; and T represents the temperature of gas in pipeline. R_g is a gas constant; g_e is gravitational acceleration; α is the elevation angle of the gas pipeline; f_c is the friction factor of gas pipeline; L is the total length of pipeline; and d is the diameter of the pipeline.

The law of conservation states that mass can neither be created nor destroyed. Equation (1) indicates that the net mass rate of flow out of a differential volume of fluid is equal to the rate of decrease of mass within the differential volume. Equation (2) resulted from Newton's second law (law of momentum), which indicates that the sum of forces acting on the gas particles is equal to the rate of increase of momentum

of natural gas particles at an instant in time. In Eq. (2), the terms $2f_c \cdot \rho \cdot v^2/d$, $\rho \cdot g_e \cdot \sin \alpha$, $\partial(\rho \cdot v)/\partial t$, and $\partial(\rho \cdot v^2)/\partial z$ define the hydraulic friction force, force of gravity, natural gas inertia, and dynamic pressure of flowing gas, respectively. In high-pressure gas pipelines, dynamics would take longer (hours). Accordingly, the convective acceleration terms, $\partial(\rho \cdot v)/\partial t$, $\partial(\rho \cdot v^2)/\partial z$, and $\rho \cdot g \cdot \sin \alpha$, contribute less than 1% to the solution of Eq. (2) under normal operating conditions.^{20,22} Hence, such terms are neglected here for simplification.^{18,19}

Equation (3) is derived from the law of conservation of energy. In order to solve Eqs. (1)–(4), it is required to know the value of Ω . In practice, $\Omega \neq 0$, as there is no thermal equilibrium between a natural gas pipeline and its surroundings. Hence, we would need additional equations to model the heat conduction process. However, the assumption of isothermal flow is valid in the case of slow transients caused by fluctuations in demand and natural gas injections.^{18–23} Accordingly, the pipeline would have sufficient time to reach its thermal equilibrium. The surrounding environment would dissipate natural gas temperature changes caused by the compression and expansion of natural gas. The natural gas temperature T is assumed to be the same as that of its surroundings. So, Eq. (3) would become redundant if we are not concerned about the value of Ω .

$$\pi = \rho \cdot Z_{avg} \cdot R_g \cdot T_{avg}. \quad (5)$$

In Eq. (4), the natural gas pressure is a function of the natural gas density, compressibility factor, and natural gas temperature. We use Eq. (5) instead of Eq. (4) under an isothermal process^{20,22} in which the average temperature of gas pipeline T_{avg} at time t and the average compressor factor of gas pipeline Z_{avg} are assumed to be constant.

After ignoring Eq. (3) and making reasonable approximations described above, we substitute the natural gas mass flow $Gf = \rho \cdot v \cdot S$, transient parameters of natural gas pipelines $K_1 = \frac{Z_{avg} R_g T_{avg,t}}{S}$, $K_2 = \frac{4f_c Z_{avg} R_g T_{avg,t}}{d S^2}$, and Eq. (5) into Eqs. (1) and (2), which result in Eqs. (6) and (7).^{18,19} S represents the area of the cross section of the gas pipeline. The following two equations are used hereafter:

$$\frac{\partial(\pi_{zt})}{\partial t} + K_1 \frac{\partial(Gf_{zt})}{\partial z} = 0, \quad (6)$$

$$\frac{\partial(\pi_{zt}^2)}{\partial z} + K_2 \cdot Gf_{zt}^2 = 0. \quad (7)$$

If we use Gf to represent gas mass flow, then, the steady-state Weymouth equation, $Gf_t^2 = C \sqrt{|\pi_{z=0,t}^2 - \pi_{z=L,t}^2|}$, is obtained by integrating Eq. (7) over the length of pipeline, where C is a constant that is equal to $\sqrt{1/K_2 L}$.

B. Modeling of compressors

A pressure loss occurs when the natural gas flow encounters pipeline resistance. Compressors are installed at intervals along the natural gas pipeline to compensate for the

pressure loss. The power of centrifugal compressor cm (the index of the compressor) is governed by the following:

$$CH_{cmt} = Gf_{cmt} \cdot (k2_{cm} \cdot PR_{cmt}^{k3_{cm}} - k1_{cm}), \quad (8)$$

where CH_{cmt} represents power of compressor at time t . $k1_{cm}$, $k2_{cm}$, and $k3_{cm}$ are empirical parameters of compressors.^{11,18,19,24,25} Gf_{cmt} represents the natural gas mass flow through the compressor cm , where

$$CH_{\min,cm} \leq CH_{cmt} \leq CH_{\max,cm}. \quad (9)$$

The pressure ratio PR in Eq. (8) is within a feasible range given in Eq. (10), which is based on compressor characteristics. π_{out} and π_{in} represent pressures at the outlet and inlet of the compressor,

$$PR_{\min,cm} \leq PR_{cmt} = \frac{\pi_{out,cmt}}{\pi_{in,cmt}} \leq PR_{\max,cm}. \quad (10)$$

Compressors can be driven by either natural gas or electricity. Natural gas compressors would consume additional natural gas that is withdrawn from either the inlet or outlet of the compressor to drive turbines. The amount of consumed natural gas is proportional to the power of the compressor $F_{cf,cm}(CH_{cmt})$.

C. Nodal natural gas flow balance

Natural gas nodes are defined as junctions of pipelines and compressors where gas wells inject natural gas into the gas network and natural gas loads withdraw natural gas from the network. The natural gas pressure associated with each node is within a range stated by Eq. (11). The output of gas well GP and the natural gas load shedding GSL are restricted by Eqs. (12)–(13), where na represents an index of a node in the gas network, gi represents an index of the gas well, and gl represents an index of the gas load. GL denotes gas demand.

$$\pi_{\min,na} \leq \pi_{nat} \leq \pi_{\max,na}, \quad (11)$$

$$GP_{gi,\min} \leq GP_{gi} \leq GP_{gi,\max}, \quad (12)$$

$$0 \leq GSL_{gl} \leq GSL_{\max,gl} \leq GL_{gl}. \quad (13)$$

The nodal gas flow balance is modeled by Eq. (14), which indicates that the natural gas flow injected into a node na is equal to the natural gas withdrawn from the node na . $g_{na}()$ represents a gas flow mismatch of the node na .

$$\begin{aligned} g_{na}(\pi, CH, GP, GSL, GL) = & - \sum_{nb \in na} Gf_{na \rightarrow nb,na} + \sum_{gi \in na} GP_{gi} \\ & - \sum_{gl \in na} GL_{gl} - GSL_{gl} \\ & - \sum_{cm \in na} F_{cf,cm}(CH_{cm}) = 0, \end{aligned} \quad (14)$$

where $nb \in na$ means there is a pipeline or compressor between na and nb . $gi \in na$ and $gl \in na$ mean there is a gas well or gas load connected to na . $Gf_{na \rightarrow nb,na}$ is the gas mass flow injected to na through the branch between na and nb .

The boundary conditions for PDE (6) and (7) are stated as follows: at $t=0$, initial values are given by various measures in the natural gas transmission system. At the beginning and the terminal ends of a pipeline, gas flows satisfy the nodal gas flow balance. If the pipeline flow from na to nb is positive, boundary conditions for the pipeline PDE are stated as in Eqs. (15) and (16),

$$\pi_{t,z=0} = \pi_{nat}, \pi_{t,z=L} = \pi_{nbt}, \quad (15)$$

$$Gf_{t,z=0} = -Gf_{na \rightarrow nb,na}, Gf_{t,z=L} = Gf_{na \rightarrow nb,nb}. \quad (16)$$

III. FORMULATION OF COORDINATED SCHEDULING PROBLEM

A. Scheduling model for electric power system

Traditionally, electric power and natural gas transmission systems are scheduled independently without any coordination. In electric power systems, the ISO executes the hourly SCUC to minimize the system operating costs in Eq. (17), while satisfying the prevailing UC constraints and power transmission network constraints in Eqs. (18)–(23). I is the binary indicator for generator ON/OFF status; SU and SD represent the startup and shutdown cost of generators; σ represents fuel price; $F_{ef,i}()$ represents the fuel consumption of generators; and P is generation dispatch.

$$\text{Min} \sum_t \sum_i [\sigma_i \cdot F_{ef,i}(P_{it}) \cdot I_{it} + SU_{it} + SD_{it}] \quad (17)$$

s.t.

$$\text{Power and load balance constraint} \quad (18)$$

$$\text{System operating reserve requirements} \quad (19)$$

$$\text{Individual generator limits (max / min capacity, ramp rate limits, and min on/off time}^{16,17,26}) \quad (20)$$

$$\text{Emission limits (CO}_2\text{, SO}_2\text{, and NO}_x\text{)} \quad (21)$$

$$\text{Network constraints (alternating current [AC] or lossless linear power flow equations}^{10,14}) \quad (22)$$

$$\text{Fuel constraints (limits for usage of oil, coal, natural gas, and so on)} \quad (23)$$

B. Scheduling model for natural gas system

The natural gas supply and transportation sectors were unbundled in the 1980s; a variety of contracts (as shown in Table I) appeared as the market evolved. Transportation services with different priority orders are described:²⁷

- No-Notice: The customer can use natural gas, whether nominated or not, on a daily basis up to its firm entitlement without incurring any balancing or scheduling penalties.
- Firm: The customer should experience no interruptions (except for force majeure) but is responsible for paying penalties for using more natural gas than its nominated amount. This service can “bump” interruptible customers.

TABLE I. Natural gas transportation and supply contracts.

Gas transportation contract			Supply contract	
No-notice	Firm	Interruptible	Take or pay	Flexible

- Interruptible: The customer can be interrupted with little notice and can be bumped by the need to deliver higher-priority services. In most cases, gas-fired power plants sign interruptible contracts.

The natural gas transmission scheduling problem is to minimize the operating cost of compressors (24) while satisfying the constraints of transient transmission of natural gas and respecting natural gas transportation contracts and pressure requirements at receiving points. $\rho_{gas,cm}$ represents the gas price for compressors,

$$\text{Min} \sum_t \sum_{cm} \rho_{gas,cm} \cdot F_{cf,cm}(CH_{cm}). \quad (24)$$

s.t. Transient-state natural gas transmission constraints (6)–(16)

The natural gas system is coupled with the electric power system by gas-fired generating units. The natural gas consumption rates of gas-fired generating units, $F_{ef,it}$, are equal to gas loads $GL_{gl,t}$ in the natural gas scheduling problem.

$$GL_{gl,t} = F_{ef,it}. \quad (25)$$

C. Bi-level model for the coordinated scheduling problem

We propose a bi-level programming formulation in Eqs. (26)–(30) for the system coordination. The upper-level problem is to optimize the operating cost $EC(x)$ of the electric power system, and x and y in Eqs. (26)–(30) represent state and decision variables in the power system and natural gas optimizations, respectively. x_c is a subvector of x for representing natural gas consumption levels by power plants. Equations (27), (28), and (30) denote constraints on unit commitment, the power transmission network, and transient natural gas transmission, respectively. The lower-level problem in Eqs. (29)–(30) represents the natural gas scheduling optimization problem, which is embedded as a constraint into the upper-level optimization problem. $GC(y)$ denotes the operating cost of compressors. Technically, we can model the problem as a bi-level programming problem in reverse of which the upper level minimizes the natural gas operating cost. Because we model the scheduling problem from the ISO's viewpoint in this paper, we keep the electric power scheduling problem as the upper problem.

$$\text{Min}_x EC(x) \quad (26)$$

$$\text{s.t. } EU(x) \leq 0 \quad (27)$$

$$EN(x) \leq 0 \quad (28)$$

$$\text{Min}_y GC(y) \quad (29)$$

$$\text{s.t. } GN(x_c, y) \leq 0. \quad (30)$$

By ignoring Eq. (29), the bi-level programming problem will be transferred into Eq. (31). Here, LB provides a lower bound for the primal problem in Eqs. (26)–(30).

$$LB = EC(x^*, y^\#) = \text{Min}_x \{EC(x) | (27), (28), (30)\}. \quad (31)$$

Electricity and natural gas markets are linked as vertically oriented markets, of which gas-fired power plants are the demand side of the gas market and the supply side of electric power market at the same time. In practice, natural gas operators would respect the contract or natural gas load requested from electric power plants unless delivering and supplying such an amount of natural gas by gas wells and pipelines is physically infeasible. Thus, the natural gas transmission operator seldom sheds natural gas loads (power plants) to reduce compressor costs. Such loads can only be mitigated by the other natural gas loads with higher transportation priorities when there is congestion.

Based on a fixed x_c^* provided by Eq. (31), we solve Eq. (32) to obtain an optimal solution y^* . $EC(x^*, y^*)$ is an upper bound for Eqs. (26)–(30).

$$y^* = \text{Arg min}_y \{GC(y) | (30)\}. \quad (32)$$

Apparently, $UB = EC(x^*, y^*) = EC(x^*, y^\#) = LB$, so (x^*, y^*) is the optimal solution.

The generalized L-shaped decomposition (Benders) is applied to decompose the optimization problem in Eq. (31) into the UC upper-level problem in Eq. (33), the power transmission network constraints check problem in Eq. (28), and the natural gas transmission network constraints check in the lower-level problem in Eq. (30).

$$\text{Min}_x \{EC(x) | (27)\}. \quad (33)$$

D. Coordinated scheduling scheme

Fig. 2 depicts the flowchart of the electricity and natural gas scheduling coordination. The integrated process is divided into the ISO and the natural gas operator problems, respectively. The ISO or the utility operator would calculate the hourly UC and dispatch that would satisfy the hourly electricity load forecast. The load shedding will be employed if the available generation would not be able to supply the electricity demand. Otherwise, based on the UC and dispatch solutions, the ISO conducts the security analysis to satisfy network constraints in contingencies. The power transmission check iterates with UC via the power transfer distribution factors (PTDFs) or Benders cuts to mitigate transmission violations.^{18,20} If there is no violation in the power transmission network, the ISO determines the natural gas consumption of gas-fired generating units and submits the hourly gas demand to the natural gas operators.

The natural gas transmission operators would collect the information on the natural gas demands, gas contracts, natural gas transmission parameters, initial pressures, and

FIG. 2. Flowchart for the coordination of ISO and natural gas operator.

planned outages of natural gas pipelines. The natural gas feasibility check will examine the feasibility of the natural gas transmission system for serving the requested natural gas loads. If the natural gas transmission check is rendered infeasible, natural gas fuel constraints will be formed by cutting planes for gas-fired power plants and fed back to the ISO for the rescheduling of daily UC. The iterative process between SCUC and the natural gas transmission feasibility check will continue until the natural gas transmission flow is feasible. Accordingly, the SCUC solution will be fixed, and the natural gas transmission operator will continue to schedule compressors, storage facilities, and line pack resources by minimizing the operating cost of compressors.

IV. SOLUTION OF THE COORDINATED SCHEDULING PROBLEM

A. Solution of SCUC

The UC problem is a mixed-integer, nonlinear program that will be linearized and solved on the basis of the branch-

FIG. 3. Grid points in the finite difference scheme.

and-cut method.^{15,28,29} The power transmission feasibility check in the lower-level problem can be solved by linear programming (LP) and iterating with UC via PTDF or the Benders decomposition method.^{15–17}

B. Implicit finite difference approximation

The analytical method can provide the continuous solution for PDE by the compact mathematic expression if the region and boundary values of dependent variables are defined. Compared to the analytical method, numerical methods are available to evaluate the dependent variables at discrete points in a span of time and space as shown in Fig. 3. We adopt the Euler finite difference numerical method to approximate PDE in Eqs. (6)–(7) by replacing derivative expressions in space and time with equivalent difference quotients. Generally, implicit methods offer better numerical stability than do explicit methods, because explicit methods calculate dependent variables at a later time by using those at the current time, whereas implicit methods find a solution by solving an equation involving dependent variables in both the current time and the future. Equations (8)–(9) are obtained by applying the backward Euler method and the midpoint Euler method, which are applied according to implicit methods. A higher-order finite difference method, such as the Runge-Kutta method, may demonstrate more accurate results. However, using the Runge-Kutta method instead of the implicit Euler method will not affect the effectiveness of our proposed model.

In Eqs. (34)–(35), the n and t indices correspond to different grid points. Obviously, increasing the number of points in Fig. 3 can enhance the numerical accuracy but will also entail longer computing times. We modify the number of grid points by adjusting the step size Δz and Δt . The state variables at $t=0$ are given as initial values. In addition, Eq. (34) is replaced by Eqs. (36) and (37).

$$\frac{\pi_{t,n} - \pi_{t-1,n}}{\Delta t} = \frac{K_1}{2\Delta z} (Gf_{t,n-1} - Gf_{t,n+1})$$

$$t \in \{1, 2, \dots, NT\}, n \in \{1, 2, \dots, N-1\}, \quad (34)$$

FIG. 4. 118-bus power system.

$$\frac{\pi_{t,n-1}^2 - \pi_{t,n+1}^2}{2\Delta z} = K_2 \cdot Gf_{t,n}^2$$

$$t \in \{0, 1, \dots, NT\}, n \in \{1, 2, \dots, N-1\}, \quad (35)$$

$$\frac{\pi_{t,n} - \pi_{t-1,n}}{\Delta t} = \frac{K_1}{\Delta z} (Gf_{t,n} - Gf_{t,n+1})$$

$$t \in \{1, 2, \dots, NT\}, n = 0, \quad (36)$$

$$\frac{\pi_{t,n} - \pi_{t-1,n}}{\Delta t} = \frac{K_1}{\Delta z} (Gf_{t,n-1} - Gf_{t,n}) \quad t \in \{1, 2, \dots, NT\}, n = N.$$

$$(37)$$

As a result, PDEs are transformed into a set of algebraic equations in Eqs. (34)–(37), which are denoted in Eq. (38) for the sake of simplicity as

$$h(Gf, \pi) = 0. \quad (38)$$

C. Natural gas transmission feasibility check

The natural gas transmission feasibility check in the lower-level problem will minimize the sum of slack variables SL on each node, while satisfying the transient formulation of natural gas pipelines, pressure constraints, and compressor constraints, as well as complying with natural gas transportation contracts for the requested natural gas load $\hat{G}\hat{L}$. The natural gas load shedding is implemented for the gas loads with lower priority. Here, $GSL_{\max} = 0$ for loads with firm transportation contracts. We use the successive LP (Refs. 30 and 31) to solve the following optimization problem iteratively:

$$\text{Min } \omega(\hat{G}\hat{L}) = \sum_{na=1}^{NN} (SL), \quad (39)$$

TABLE II. Parameters of interstate pipeline.

Maximum pressure	Minimum pressure	Parameter K_1	Parameter K_2	Parameter C	Length L
500 pounds per square inch gauge (psig)	400 psig	0.05	2×10^{-6}	50	200 miles

TABLE III. Parameters of compressor and natural gas well.

Gas compressor									Gas well	
$F_{cf,cm}(CH_{cm}) = cf + bf \cdot CH_{cm} + af \cdot CH_{cm}^2$										
k1	k2	k3	Min. power (horsepower [hp])	Max. power (hp)	af (MBtu/hp ² h)	bf (MBtu/hph)	cf (MBtu/h)		Max. output (MBtu/h)	Min. output (MBtu/h)
0.1	0.17	0.15	500	2000	0.0001	0.15	25		5000	20,000

s.t.

$$\nabla h(Gf, \pi) \cdot \begin{bmatrix} \Delta Gf \\ \Delta \pi \end{bmatrix} = -h(Gf, \pi), \quad (40)$$

$$\begin{bmatrix} \frac{\partial g}{\partial \pi} & \frac{\partial g}{\partial CH} & GA & GB \end{bmatrix} \cdot \begin{bmatrix} \Delta \pi \\ \Delta CH \\ \Delta GP \\ \Delta GSL \end{bmatrix} + SL$$

$$\mu = -g(\pi, CH, GP, GL - GSL) \quad (41)$$

$$0 \leq GSL + \Delta GSL \leq GSL_{\max} \leq GL, \quad (42)$$

$$\pi_{\min} \leq \pi + \Delta \pi \leq \pi_{\max}, \quad (43)$$

$$GP_{\min} \leq \Delta GP + GP \leq GP_{\max}, \quad (44)$$

$$CH_{\min} \leq CH + \Delta CH \leq CH_{\max}, \quad (45)$$

$$PR_{\min}(\pi_{in} + \Delta \pi_{in}) \leq \pi_{out} + \Delta \pi_{out} \leq PR_{\max}(\pi_{in} + \Delta \pi_{in}), \quad (46)$$

$$0 \leq SL. \quad (47)$$

Then, we update variables by applying Eq. (48). The iterative process will continue until $\Delta \pi^{(k)}$, $\Delta CH^{(k)}$, $\Delta GP^{(k)}$, $\Delta GL^{(k)}$, and $\Delta GSL^{(k)}$ are less than a specified ε , where k represents the iteration number; GA is the node-gas supplier incidence matrix; GB represents node-gas load incidence matrix; GK is the node-node connection incidence matrix; and GD is the gas-withdrawing node-compressor incidence matrix.

Once the iterative process is completed, a non-negative objective function in Eq. (39) that is less than the specified tolerance indicates that the natural gas transmission network can support natural gas loads of electricity sectors. Otherwise, a natural gas fuel constraint (Benders cut) given

in Eq. (49) will be generated and added to the SCUC formulation

$$\begin{bmatrix} \pi^{(k+1)} \\ CH^{(k+1)} \\ GP^{(k+1)} \\ GSL^{(k+1)} \end{bmatrix} = \begin{bmatrix} \pi^{(k)} \\ CH^{(k)} \\ GP^{(k)} \\ GSL^{(k)} \end{bmatrix} + \begin{bmatrix} \Delta \pi^{(k)} \\ \Delta CH^{(k)} \\ \Delta GP^{(k)} \\ \Delta GSL^{(k)} \end{bmatrix}, \quad (48)$$

$$\omega(GL) = \omega(GL) + \mu^T \cdot GB \cdot (GL - GL) \leq 0, \quad (49)$$

where μ is the dual variable vector obtained by solving LP in the last iteration.

The transient model of the natural gas transmission feasibility check in the lower-level problem is coupled on an hourly basis. However, that of the steady-state model is decoupled on an hourly basis, such that it can be solved by parallel processing. In addition, Eq. (40) represents many constraints and variables if the number of grid points in Fig. 3 is large. Therefore, the computing time of the transient model is usually higher than that of the steady-state model.

D. Solution of natural gas scheduling problem

The natural gas scheduling problem is also solved by the successive LP. The natural gas transmission feasibility check in the lower-level problem can provide an initial value for the solution of the natural gas scheduling problem. In general, $F_{cf,cm}()$ is convex. The objective function in Eq. (39) is replaced by Eq. (50). However, pipeline and compressor equations may make the lower-level problem non-convex. Therefore, if the initial operating point of the natural gas problem is not close to the global optimal points, the solution

FIG. 5. Interstate pipeline.

FIG. 6. Hourly natural gas and electricity load.

TABLE IV. Unit commitment in case 1.

Unit	Hours (0–24)																							
1013	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0
1014	1	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
1019	1	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
1022–1023	1	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
1026	1	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
1034–1035	1	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
1047–1048	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1051	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	1	0
1052	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	0
4001	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	3	3	1	1	0
4002	0	0	0	0	0	0	2	2	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
4003	0	1	1	0	0	0	1	1	3	3	4	4	4	4	4	4	4	4	4	4	4	4	4	4
4004	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	3	3	4	4	4	4	4	4	3
4005	0	0	0	0	0	0	2	2	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
4006	0	1	1	1	1	3	3	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
4007	0	2	2	2	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
4008–4009	0	1	1	1	3	3	3	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
4010	0	0	0	0	0	1	1	3	3	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
4011	0	0	0	1	1	3	3	3	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
4012	0	1	1	1	1	3	3	3	3	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
6002	0	1	1	0	0	0	0	1	1	1	1	1	1	1	0	1	1	1	0	0	0	1	0	0
6006	0	0	0	0	0	0	0	0	1	0	1	1	0	0	0	1	1	0	1	1	1	1	0	0

may be a local optima. Heuristic methods may be considered in this case to find the best possible solution.

$$\text{Min} \sum_{t=1}^{NT} \sum_{cm=1}^{NC} \rho_{gas,cm} \cdot \frac{\partial F_{cf,cm}(CH_{cmt})}{\partial CH_{cmt}} \cdot \Delta CH_{cmt}. \quad (50)$$

V. CASE STUDIES

A modified Institute of Electrical and Electronics Engineers (IEEE) 118-bus system, as shown in Fig. 4, is used to study the coordinated scheduling. The power system has 54 fossil fuel units, 12 combined-cycle units, 7 hydro units, 186 branches, 14 capacitors, 9 tap-changing transformers, and 91 demand sides. Tables II and III show the parameters of the pipeline, compressor, and gas well. All 12 combined cycle units with interruptible transportation contracts are supplied by an interstate pipeline and a compressor, as shown in Fig. 5. Fuel prices are \$1.4 per one thousand British

thermal units (MBtu) for natural gas and 1\$/MBtu for coal. The test data are given in motor.ece.iit.edu/data/Transient_gastransmission_118test.xls. Fig. 6 shows the hourly electrical and firm natural gas loads supplied by interstate pipelines. In order to discuss the effectiveness of the proposed approach, as well as the impact of the transient-state natural gas flow model on SCUC and natural gas scheduling results, we solve the coordination model in three different cases. The program is coded in C++ and solved by CPLEX 9.0 on a 2.6-GHz personal computer.

Case 1: Coordinated scheduling with steady-state natural gas transmission constraints

We calculate the hourly SCUC solution by considering both the dc transmission constraints and the steady-state natural gas transmission constraints. In the steady-state natural gas flow case, the maximum pipeline flow is 15 000 MBtu/h, which is based on the Weymouth equation. The natural gas usage of combined cycle units 4001–4012 is curtailed at certain hours to mitigate the natural gas

TABLE V. Daily scheduling coordination results in cases 1–3.

Daily results	Case 1	Case 2	Case 3
Operating cost of electric power system (\$)	2 046 006	2 044 479	2 037 255
Natural gas consumed by compressor (MBtu)	8965	12 273	5056
Natural gas well output (MBtu)	322 031	408 621	201 383
Gas delivered to power plants (MBtu)	181 766	163 200	220 649
Electric power generated by gas plants (megawatts [MW])	13 962	12 995	17 316

FIG. 7. Hourly natural gas delivered to power plants in cases 1–3.

FIG. 9. Hourly natural gas consumed by compressor in cases 1–3.

FIG. 8. Hourly natural gas well output in cases 1–3.

TABLE VI. Initial parameters of interstate pipeline.

Initial status of pipelines	Initial pressure (psig)		Mass gas flow (MBtu)	
	Starting point	Ending point	Starting point	Ending point
Case 2	448	500	10 088	10 088
Case 3	400	458	10 029	10 029

TABLE VII. Unit commitment in case 2.

Unit	Hours (0–24)																							
1013	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	
1014	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	
1019	1	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	
1022–1023	1	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	
1026	1	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	
1034–1035	1	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	
1047	1	0	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	0	
1048	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	0	
1051	1	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	0	
1052	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	
4001	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	0	0	
4002	0	0	0	0	0	0	1	1	3	3	4	4	4	4	4	4	4	4	4	4	4	4	4	
4003	0	1	1	0	0	0	0	2	2	4	4	4	4	4	4	4	4	4	4	4	4	4	4	
4004	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2	2	4	4	4	4	3	
4005	0	0	0	0	0	0	0	0	0	0	0	0	0	2	2	4	4	4	4	4	4	4	4	
4006	0	1	1	1	1	1	3	3	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	
4007–4009	0	0	0	0	2	2	2	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	
4010	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
4011	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2	2	4	4	4	4	4	
4012	0	0	0	2	2	2	2	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	
6002	0	1	1	0	0	0	0	1	1	1	1	1	1	1	1	1	1	0	0	0	1	0	0	
6006	0	0	0	0	0	0	0	0	0	1	1	1	0	0	0	1	1	0	1	1	1	1	0

FIG. 10. Pressure at starting and ending points of the pipeline in case 2.

FIG. 11. Hourly pressure at starting/ending points of pipeline in case 3.

transmission congestion at hours 8–24. Table IV shows the hourly commitment in which the hour 0 represents the initial condition. Tables IV and VII list only the units with revised hourly commitment.

The daily operating cost of the power system is \$2 046 006. After the power system schedule is set, we minimize the operating cost of the compressors, which is based on steady-state natural gas transmission constraints. Table V shows that the compressor will consume 8965 MBtu over the course of the next day. The hourly gas withdrawn from the pipeline, the hourly natural gas consumed by compressor, and the hourly gas well output consumed by the combined-cycle units are shown in Figs. 7–9.

Case 2: Coordinated scheduling with transient natural gas flow model based on a lower initial line pack

We solve the generation scheduling problem again by considering the proposed transient-state model for natural gas flows. The pipeline is partitioned into several segments in its 200-mile length. The time interval is 1 h, and the length interval is 10 miles. Accordingly, PDEs of the pipeline with boundary conditions are transformed into a set of difference equations by the proposed implicit finite difference methodology. Table VI shows the initial pressures of the pipeline. The lower initial pressures in case 2 represent a smaller amount of natural gas contained in the pipeline after the previous day's operation. The hourly UC is given in Table VII, in which combined cycle units 4001–4012 generate less power (in MW) at many hours of the day as compared to case 1, and more coal units are committed. Fig. 7 shows that more natural gas is delivered to combined-cycle units in case 2 at h 19–23 when the electricity load is at peak. As a result, the daily operating cost of the power system is \$2 044 476 in case 2, which is still lower than the cost realized in case 1. In order to satisfy peak hour natural gas demands at the ending point of the pipeline, the natural gas compressor has to charge the pipeline at the beginning hours of the period. Fig. 10 shows that the pressure level at the starting point of the pipeline increases gradually.

Case 3: Coordinated scheduling with transient gas flow model based on a higher initial line pack

If the given initial pipeline pressure is higher, there will be more natural gas contained in the pipeline before the current operating day. Therefore, the pipeline can supply more natural gas to gas loads. Thus, even though the hourly UC results in cases 1 and 3 are the same, the dispatch in case 3 is more economical. The daily operating cost of the power system in case 3 is \$2 037 255, which is lower than that of cases 1 and 2. In case 3, there is no violation in the natural gas transmission feasibility check in the lower-level problem. Fig. 11 shows that pressures at starting and ending points of the pipeline gradually decline, releasing the additional line pack resources to natural gas loads. The generation of combined-cycle units 4001–4012 is no longer limited by the natural gas transmission congestion. Table V shows that the total daily

generating power is 17 316 MW, which is the highest in three cases. Figs. 8–9 show that the operating costs of compressor and the gas well output in case 3 are much lower than those found in cases 1 and 2 because of its higher initial line pack value. By comparing the results in three cases, we notice that the steady-state and transient-state models may yield two distinct results for the coordinated scheduling of power and natural gas systems.

VI. CONCLUSIONS

This paper has developed a bi-level coordinated scheduling model for interdependent electricity and natural gas infrastructures. The transient model of natural gas flow is considered in the proposed model. The natural gas pipeline is modeled as a set of partial differential equations. An implicit finite difference method is introduced to transform the equations into difference equations. The paper shows that the proposed decomposition methodology and the coordination scheme can be applied to solve the proposed coordinated scheduling problem effectively. The case studies demonstrate that the applications of the steady-state and the transient-state models of natural gas flows would present different results for the coordinated scheduling of interdependent electricity and natural gas systems. It is also shown that the steady-state natural gas flow model, which would neglect the inherent storage capability of pipeline and the slower traveling speeds of natural gas flows, may result in impractical results and suboptimal schedules in short-term operation. The proposed coordinated scheduling model with the transient-state natural gas transmission formulation can be used in the daily operation scheduling, real-time operation, and post-contingency rescheduling.

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Impact of Natural Gas System on Risk-Constrained Midterm Hydrothermal Scheduling

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Abstract—This paper studies the impact of natural gas (NG) contracts and constraints on a GENCO's midterm risk-constrained hydrothermal scheduling problem. The NG contracts and constraints are modeled as a set of linear equations. The proposed model utilizes the stochastic price-based unit commitment (PBUC). The PBUC hourly solution considers uncertainties of market prices for energy and ancillary services, uncertainties of natural water inflows, and random NG infrastructure interruptions in Monte-Carlo scenarios. Illustrative examples analyze the GENCO's risk levels when considering midterm schedules for generating units, target payoffs, and usages of water inflow, NG and other thermal resources. Simulation results show that a GENCO's midterm schedules and financial risks could be impacted significantly with the consideration of NG contracts and constraints.

Index Terms—Interdependency of natural gas and electricity, financial and physical risks, generation companies, stochastic price-based unit commitment, natural gas contracts

NOMENCLATURE

Indices:

h	Index of hydro units
i	Index of coal units
j	Index of NG units
k	Index of pumped-storage units
l	Index of hydro catchments
m	Index of pipelines
n	Index of NG contracts
p	Index of power plants
r	Index of subareas
s	Index of scenarios
t	Index of time periods (hour)
w	Index of NG storage facilities

Dimensions:

NCM	Number of hydro catchments
NCO	Number of coal units
NGC	Number of NG gas contracts
NGS	Number of NG gas storage facilities
NH_l	Number of hydro units of a hydro catchment l
NNG	Number of NG units
NPL	Number of NG plants
NPP	Number of NG pipelines
NPS	Number of pumped-storage hydro units
NS	Number of scenarios
NSA	Number of NG subareas

NT

Number of time periods under study

Sets:

SCT	Set of NG units utilizing a gas contract
SFC	Set of firm NG contracts
SIC	Set of interruptible NG contracts
SPL	Set of NG units in a plant
SPP	Set of gas contracts belonging to a pipeline
SSA	Set of NG units in a subarea
SST	Set of NG units sharing a NG storage facility

Variables:

C_{ns}	Cost of NG usage from contract n in scenario s
C_{ws}	Cost of NG usage from storage facility w in scenario s
F	Fuel usage by unit
OR	Operating reserve
P	Power generation
PF_s	GENCO's payoff in scenario s
q^{out}	NG withdrawn from storage facility w
q^{in}	NG injected to storage facility w
V_{wts}	Volume of NG in storage facility w at time t in scenario s
$RISK_s$	GENCO's downside risks in scenario s
SD	Shutdown cost
SR	Spinning reserve
SU	Startup cost
λ	Lagrange multiplier
γ_s	Lagrange multiplier for risk constraint in scenario s

Constants:

α_n	Interruption rate of NG contract n
β_n	Restore rate of NG contract n
$C_{0,n}$	Fixed cost for firm NG contract n
EDR	Expected downside risk tolerance
$F_{\max, jt}$	Maximum NG usage allowed for unit j at time t
$F_{\max, j}$	Maximum NG usage allowed for unit j in one year
p_s	Probability for a scenario s
T_0	Target payoff of a GENCO
U_{nts}	Availability of NG contract n at time t in scenario s
$V_{\max, w}$	Maximum NG volume limit in storage facility w
$V_{\min, w}$	Minimum NG volume limit in storage facility w
$V_{0, w}$	Volume of NG in storage facility w at time 0
$V_{NT, w}$	Volume of NG in storage facility w at time NT
p_n	Steady-state availability of NG contract n

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q_n	Steady-state unavailability of NG contract n
ρf_{its}	Fuel price of coal unit i at time t in scenario s
ρg_{ts}	Market price for energy at time t in scenario s
ρ_n	Price of one MCF of interruptible NG contract n
ρor_{ts}	Market price for operating reserve at time t in scenario s
ρsr_{ts}	Market price for spinning reserve at time t in scenario s
ρ_w	Unit price of one MCF of gas withdrawal from NG storage facility w

Abbreviations:

GENCO	Generation Company
MIP	Mixed Integer Program
MMCF	Million cubic feet
NG	Natural Gas
PBUC	Price based unit commitment

I. INTRODUCTION

GENCOs are responsible for the midterm operation planning which provides a basis for the optimal hourly bidding in a day-ahead market. The midterm operation planning will determine the optimal utilization of resources such as fuel, emission allowance, and natural water resources [1]-[3]. The modeling of NG contracts in midterm operation planning studies provides a more robust scheduling of hydrothermal assets when considering uncertainties related to market prices, NG interruptions, and water inflows.

Several approaches are available for the optimal midterm operation planning problem. A variable metric method was used in [4] to solve the dual maximization for achieving a good convergence property. A composite representation of thermal and hydro units was used in [5] for economic dispatch based on weekly and monthly requirements. A dual-decomposition of long-term planning problem was applied in [6],[7] for setting up easy-to-solve problems in subperiods. The framework in [8] is able to consider on and off-peak energy prices and user controlled multi-scenario water inflows. The interior point method is applied to solve the long-term scheduling problem, in which the hydro unit characteristics are linearly modeled. A two-stage dynamical programming (DP) method was proposed in [9] which is capable of handling nonconvex, nonlinear and stochastic characteristics of the problem. However, the DP technique might not be tractable in multi-reservoir systems due to the dimensionality problem. Reference [10] compared the stochastic dynamic programming and the deterministic optimization models with an inflow forecasting model for the long-term hydrothermal scheduling problem. The reference concludes that the two methods have similar performance and the deterministic model is superior in dry hydro periods. A two-phase nonlinear optimization model was proposed in [11] to model the integrated operation of NG network and power systems. In [12] and [13], a nonlinear optimization model was proposed by merging the traditional optimal power flow and NG network constraints. The short-term scheduling of integrated NG network and hydrothermal power system was solved in [14] by applying Lagrangian relaxation and dynamic programming. An integrated model was proposed in [15] for

studying the interdependency of electricity infrastructure and NG system and the social sustainability of energy infrastructures. The integrated model considered NG network constraints as daily and hourly limits on pipelines, subareas, power plants, and generating units, and incorporated these constraints into the optimal solution of short-term security-constrained unit commitment.

In addition to the short-term NG scheduling, interdependencies were considered in midterm NG planning studies. A network-based stock and flow type model was created in [16] to analyze the NG network response to disruptions. The NG flows between regions were represented and stocks were the regional NG storages. The model was used to assess the NG network against transmission disruption scenarios. However, the model did not include contractual NG deliveries to other users which would likely worsen electric power supply scenarios. For example, there might be a sufficient transmission capacity available on a NG pipeline which would feed power plants. The NG flow can ramp up quickly in the event of a pipeline disruption elsewhere or an unseasonably cold weather. However, that capacity could have already been contracted to other users. Logically, such emergencies would take precedent, but legally there might be no way out of contractual agreements. An analytical framework was proposed in [17] to study physical and economic aspects of interdependent infrastructures such as electric power, petroleum, NG, water, and communications systems. A modeling and analyses tool was developed to capture interdependencies, evaluate potential effects of disruptions in one infrastructure, and suggest strategies to mitigate shortcomings.

This paper incorporates the NG infrastructure model presented in [15] to develop an extended framework for the risk-constrained stochastic midterm hydrothermal scheduling problem [18]. The main theme of this paper is to assess the impact of the NG infrastructure and contracts on the stochastic midterm planning of electric power systems. Consider a GENCO with hydro, thermal, and NG contacts for supplying its gas power plants. Since the residential NG demand is very high at certain seasons, NG suppliers in severe weather conditions could interrupt the supply to power plants. Such interruptions could have a significant impact on the GENCO's expected payoffs. In addition, when the risk is considered, the behavior of NG units could vary under different hydro conditions. For instance, NG units would tend to increase their generation output for lowering the total financial risk. This case could occur in scenarios with water supply shortages to prevent GENCOs from defaulting on their bilateral energy contracts. However, the NG output in practice could be constrained by physical limitations and contracts.

The availability of NG storage could facilitate lower risks in such cases. The storage capacity should be determined in such cases based on forecasted market prices, and duration and frequency of NG interruptions.

The hourly MIP solution of price-based hydrothermal system presented in [18] is considered here. The NG interruptions are also considered as uncertainties similar to those of hourly market prices and water inflows. The performances of individual units for risk reduction are studied and compared with the risk reduction performance of all units

considered together to evaluate possible alternatives in a GENCO's stochastic midterm scheduling.

This paper is organized as follows. The proposed model is formulated in Section II. Detailed simulation and solution methodologies are described in Section III. Examples are given in Section IV. Section V concludes this paper.

II. STOCHASTIC MODELING OF NG INFRASTRUCTURE

This section starts by defining the objective function of midterm PBUC problem, which includes revenues and expenses for coal, NG, cascaded hydro, and pumped-storage hydro units. Generating unit constraints are discussed and NG contracts and constraints are presented. Financial risk constraints are also discussed.

The proposed objective function (1) is to maximize the expected payoff with respect to power generations (P), spinning and operating reserves (SR and OR) and unit commitment variables over all scenarios. The payoff of a scenario is defined as the difference between revenue and expense. The revenue (2) is due to sales of energy, spinning reserves, and operating reserves by coal, NG, cascaded hydro, and pumped-storage hydro units. The cost (3) includes that of i) fuel, startup, and shutdown for coal units; ii) NG contracts, storage, startup cost, and shutdown for NG units; iii) startup and shutdown for cascaded hydro units; and iv) startup cost and shutdown for pumped-storage units.

$$\text{Max: } \sum_{s=1}^{NS} p_s \cdot PF_s = \sum_{s=1}^{NS} p_s \cdot \{ \text{REVENUE}_s - \text{COST}_s \} \quad (1)$$

where

$$\begin{aligned} \text{REVENUE}_s = & \sum_{i=1}^{NCO} \sum_{t=1}^{NT} [\rho_{g_{is}} \cdot P_{its} + \rho_{sr_{is}} \cdot SR_{its} + \rho_{or_{is}} \cdot OR_{its}] \\ & + \sum_{j=1}^{NNG} \sum_{t=1}^{NT} [\rho_{g_{js}} \cdot P_{jts} + \rho_{sr_{js}} \cdot SR_{jts} + \rho_{or_{js}} \cdot OR_{jts}] \\ & + \sum_{l=1}^{NCM} \sum_{h=1}^{NH} \sum_{t=1}^{NT} [\rho_{g_{ls}} \cdot P_{hls} + \rho_{sr_{ls}} \cdot SR_{hls} + \rho_{or_{ls}} \cdot OR_{hls}] \\ & + \sum_{k=1}^{NPS} \sum_{t=1}^{NT} [\rho_{g_{ks}} \cdot P_{kts} + \rho_{sr_{ks}} \cdot SR_{kts} + \rho_{or_{ks}} \cdot OR_{kts}] \end{aligned} \quad (2)$$

and

$$\begin{aligned} \text{COST}_s = & \sum_{i=1}^{NCO} \sum_{t=1}^{NT} [\rho_{f_{its}} \cdot F_{its} + SU_{it} + SD_{it}] \\ & + \sum_{n=1}^{NGC} C_{ns} + \sum_{w=1}^{NGS} C_{ws} + \sum_{j=1}^{NNG} \sum_{t=1}^{NT} [SU_{jt} + SD_{jt}] \\ & + \sum_{l=1}^{NCM} \sum_{h=1}^{NH} \sum_{t=1}^{NT} [SU_{ht} + SD_{ht}] + \sum_{k=1}^{NPS} \sum_{t=1}^{NT} [SU_{kt} + SD_{kt}] \end{aligned} \quad (3)$$

A low-discrepancy Monte Carlo method, represented by Latin Hypercube, is used to generate a set of scenarios, which consider uncertainties in market prices, natural water inflows, and interruptions of NG interruptible contracts. The scenarios are then reduced based on backward and fast forward method. The probability p_s assigned to each scenario reflects the possibility of occurrence [19]. The details of the modeling of market prices and natural water inflows are given in [18],[20]. A two-state continuous-time Markov chain model is used to represent available states of NG interruptible contracts [21]-[23]. The objective function defined in (1) is subject to the following generating unit and NG infrastructure constraints

[18].

• Coal Unit Constraints

- a) Fuel consumption and emission allowance constraints for groups of coal units
- b) Energy and ancillary services supplied
- c) Minimum on/off time and ramping up/down constraints

• NG Unit Constraints

NG units are subject to similar constraints to those of the coal units as well as the NG network constraints that will be discussed later in this section.

• Cascaded Hydro Unit Constraints

- a) Energy and ancillary services supplied
- b) Water-to-power conversion
- c) Operating regions (water discharge limits)
- d) Reservoir volume limits
- e) Initial and terminal reservoir volumes
- f) Water balance constraint
- g) Minimum on/off time and ramping up/down constraints

• Pumped-storage Units Constraints

The pumped-storage units are subject to the same constraints b, d, e and g of the cascaded hydro-unit constraints. The energy and ancillary services, operating regions and water balance constraints are extended to consider the pumping modes of the pumped-storage units.

• NG Contracts and Constraints

The eight NG units are fed from the NG transmission network as seen in Fig. 2. There are eight units related to Pipeline 1. Consequently, these units would be subject to limits on pipelines, contracts, and plants. Pipeline 2 is divided into two zones, and if Zone 1 is considered to be geographically far from gas well, the four units located in this zone would be able to access only a proportion of pipeline capacity due to subarea constraints. The units in Zone 3 of Pipeline 2 share a storage facility to which NG could be deposited. The stored NG could be withdrawn when necessary, i.e. the pipeline outage due to seasonal interruptions. The mathematical equations for NG contracts and network constraints are provided here which are used in the stochastic midterm operation planning problem.

NG contracts are modeled as firm (take-or-pay) or interruptible contracts with NG suppliers. Firm NG contracts have fixed costs. Interruptible NG contracts are utilized if it is either economical or required to satisfy certain constraints. The cost of a firm NG contract is specified as

$$C_{ns} = C_{0,n}, \forall n \in SFC, \forall s \quad (4)$$

An interruptible NG contract will have its own quantity and price. The cost of an interruptible NG contract depends on the gas usage

$$C_{ns} = \rho_n \sum_{t=1}^{NT} F_{nts}, \forall n \in SIC, \forall s \quad (5)$$

The NG usage from a specific NG contract at a specific scenario and time is limited by the availability of specific NG contracts defined by an integer availability variable U_{nts} .

$$F_{nts} \leq F_{\max, nt} \cdot U_{nts}, \forall n, \forall t, \forall s \quad (6)$$

The NG usage from a firm contract n is equal to the contracted amount since it is prepaid.

$$\sum_{t=1}^{NT} F_{nts} = F_{\max, n}, \forall n \in SFC, \forall s \quad (7)$$

The NG usage from an interruptible contract n cannot exceed the yearly contracted limit.

$$\sum_{t=1}^{NT} F_{nts} \leq F_{\max, n}, \forall n \in SIC, \forall s \quad (8)$$

Here, daily, weekly, and monthly contract limits may be included similarly.

The steady-state NG network equations define the nonlinear relationship between the gas flow and pressure. The pressures at network nodes and the gas flows in pipelines could be calculated based on the nodal balance approach with a large computation time. The linearized constraints would not calculate these parameters at each time step; however, the physical limitations of the network could still be enforced considering the maximum capacity of the network components at each time step with a significant drop in the computation time. The linearized approach is sufficient for the purpose of this paper since the algorithm aims to find the optimum fuel and resource scheduling rather than calculating the NG network parameters at each time step.

The modeling of storage is essential for a midterm study, since the storage facility could be used both for deposit and withdrawal purposes throughout the year. The storage model for the short-term study in [15] was simply represented by a gas inflow variable in the NG unit fuel balance equation. The short-term constraints considering capacity limits on pipelines, sub-areas, power plants, and units are adopted for the midterm stochastic model by increasing the time-span and introduction of s as scenario variables.

The hourly and yearly constraints are considered in this section. The daily, weekly, and monthly limits can be included similarly. The total NG usage from a contract n of pipeline m at time t in scenario s is equal to the sum of separate NG usages by individual NG units using that contract.

$$F_{nmts} = \sum_{j \in SCT(n)} F_{jnmts}, \forall n, \forall m, \forall t, \forall s \quad (9)$$

A gas pipeline can be fed by several NG contracts. The total NG usage of pipeline m at time t in scenario s is equal to the sum of NG usage from all such contracts.

$$F_{mts} = \sum_{n \in SPP(m)} F_{nmts}, \forall m, \forall t, \forall s \quad (10)$$

Generating units that are located far from NG pumping stations can only burn a certain percentage of available NG. Accordingly, a subarea is defined for the NG consumption of such units. The total NG usage at subarea r of pipeline m at time t in scenario s is equal to the sum of NG usages by individual NG units in that subarea.

$$F_{mrts} = \sum_{j \in SSA(r)} F_{jmrts}, \forall m, \forall r, \forall t, \forall s \quad (11)$$

An NG unit j can be supplied by multiple contracts, pipelines, and NG storage facilities.

$$F_{jts} = \sum_{m=1}^{NPP} \sum_{n \in SPP(m)} F_{jnmts} + \sum_{w=1}^{NGS} (q_{jwts}^{out} - q_{jwts}^{in}), \forall j, \forall t, \forall s \quad (12)$$

where q_{jwts}^{out} and q_{jwts}^{in} are zero if the NG unit j is not connected to any storage facilities. The total NG injected into or withdrawn from the storage by individual units, which would share the same storage, is given as

$$q_{wts}^{in} = \sum_{j \in SST(w)} q_{jwts}^{in}, \forall w, \forall t, \forall s \quad (13)$$

$$q_{wts}^{out} = \sum_{j \in SST(w)} q_{jwts}^{out}, \forall w, \forall t, \forall s \quad (14)$$

The NG volume balance equation for the storage facility w is

$$V_{w(t+1)s} = V_{wts} + q_{wts}^{in} - q_{wts}^{out}, \forall w, \forall t, \forall s \quad (15)$$

The term V_{wts} is the volume of the NG storage w at time t and scenario s . This term could be obtained using the initial volume and the net injection and withdrawal amounts at each time step starting from the initial time 0 to time $(t-1)$ as

$$V_{wts} = \sum_{j \in SCT(w)} \sum_{\tau=1}^{t-1} (q_{jw\tau s}^{in} - q_{jw\tau s}^{out}) + V_{w(0)s} \quad (16)$$

The NG storage volume constraint of the storage facility w is

$$V_{\min, w} \leq V_{wts} \leq V_{\max, w}, \forall w, \forall t, \forall s \quad (17)$$

The initial and final volumes of the NG storage facility w are

$$V_{w(0)s} = V_{0,w}, \forall w, \forall s \quad (18)$$

$$V_{w(NT)s} = V_{NT,w}, \forall w, \forall s \quad (19)$$

The total cost of NG withdrawal from the storage facility w is

$$C_{ws} = \rho_w \cdot \sum_{t=1}^{NT} q_{wts}^{out}, \forall w, \forall s \quad (20)$$

The NG usage of unit j is subject to the following hourly and yearly limits

$$F_{jts} \leq F_{\max, jt}, \forall j, \forall t, \forall s \quad (21)$$

$$\sum_{t=1}^{NT} F_{jts} \leq F_{\max, j}, \forall j, \forall s \quad (22)$$

The NG units that belong to a specific power plant are subject to the following hourly and yearly limits

$$\sum_{j \in SPL(p)} F_{jts} \leq F_{\max, pt}, \forall p, \forall t, \forall s \quad (23)$$

$$\sum_{j \in SPL(p)} \sum_{t=1}^{NT} F_{jts} \leq F_{\max, p}, \forall p, \forall s \quad (24)$$

The NG usage of pipeline m is subject to the following hourly and yearly limits

$$F_{mts} \leq F_{\max, mt}, \forall m, \forall t, \forall s \quad (25)$$

$$\sum_{t=1}^{NT} F_{mts} \leq F_{\max, m}, \forall m, \forall s \quad (26)$$

The NG usage at subarea r is subject to the following hourly and yearly limits

$$F_{mrts} \leq F_{\max, mrt}, \forall m, \forall r, \forall t, \forall s \quad (27)$$

$$\sum_{t=1}^{NT} F_{mrts} \leq F_{\max, mr}, \forall m, \forall r, \forall s \quad (28)$$

• Risk Constraints

The stochastic formulation described above is a risk-neutral model that is only concerned with the optimization of expected payoff. However, a GENCO may also be concerned with its risk. A GENCO would set a target payoff T_0 , and the risk associated with its decision is measured by the failure to

meet the target payoff. That is, if the payoff for a scenario is larger than the target, the associated downside risk is zero; otherwise, it is the difference between the payoff and its target value, which is expressed as

$$RISK_s = \max \{0, T_0 - PF_s\}, \forall s \quad (29)$$

The expected downside risk should be lower than a target risk level which is stated as

$$\sum_{s=1}^{NS} p_s \cdot RISK_s \leq \overline{EDR} \quad (30)$$

III. PROPOSED SOLUTION METHODOLOGY

A. Decomposition procedure

The original problem is decomposed into subproblems for coal, NG, hydro, and pumped-storage units. The unit status indicators (I) are defined for each scenario separately. Bundle constraints are utilized to force the undistinguishable scenarios to have the same rendered decision variables, namely unit status indicators [18]. In this study, the unit status indicators are the same for every scenario. This formulation removes the necessity of using bundle constraints at the expense of a longer solution time since the decomposition is not among scenarios. The removal of bundle constraints reduces the number of Lagrange multipliers and simplifies the updating of multipliers.

A1. Decoupling expected downside risk constraint

The expected downside risk constraint (30) is the only coupling constraint among different types of generating units. The constraint can be decoupled by relaxing it into the objective function by using the Lagrange multiplier γ_s . With the constant terms dropped, we have

$$\min \sum_{s=1}^{NS} p_s \cdot (-PF_s + \gamma_s \cdot RISK_s) \quad (31)$$

Considering the definition of downside risk (29), we have

$$\min \sum_{s=1}^{NS} p_s \cdot (-PF_s + \gamma_s \cdot \max \{0, T_0 - PF_s\}) \quad (32)$$

If the payoff of a scenario s is higher than the target payoff,

$$-PF_s + \gamma_s \cdot \max \{0, T_0 - PF_s\} = -PF_s \quad (33)$$

Otherwise,

$$-PF_s + \gamma_s \cdot \max \{0, T_0 - PF_s\} = -(1 + \gamma_s)PF_s + \gamma_s T_0 \quad (34)$$

Here, (33) can be viewed as a special case of (34) where $\gamma_s = 0$. After relaxing the risk constraint, we proceed by decomposing different unit types to single unit problems.

A2. Decoupling constraints among coal units

The coal unit subproblem is given in (35). Fuel allocation and emission allowance are considered by applying the Lagrangian relaxation [18]. The coal unit subproblem is further decomposed into single coal unit i subproblems in (36).

$$\min \left\{ \sum_{i=1}^{NCO} \sum_{t=1}^{NT} \sum_{s=1}^{NS} p_s \cdot (1 + \gamma_s) \cdot \left[\begin{array}{l} \rho g_{ks} \cdot P_{its} + \rho sr_{ts} \cdot SR_{its} \\ + \rho or_{ts} \cdot OR_{its} \\ + SU_{it} + SD_{it} + \rho f_{its} \cdot F_{its} \end{array} \right] \right\} \quad (35)$$

$$\min \left\{ \sum_{t=1}^{NT} \sum_{s=1}^{NS} p_s \cdot (1 + \gamma_s) \cdot \left[\begin{array}{l} \rho g_{ks} \cdot P_{its} + \rho sr_{ts} \cdot SR_{its} \\ + \rho or_{ts} \cdot OR_{its} \\ + SU_{it} + SD_{it} + \rho f_{its} \cdot F_{its} \end{array} \right] \right\}, \forall i \quad (36)$$

A3. Hydro subproblems for each catchment

In order to avoid the decomposition of coupling constraints among hydro units in one catchment, we solve hydro subproblems for each catchment given in (37).

$$\min \left\{ \sum_{h=1}^{NH} \sum_{t=1}^{NT} \sum_{s=1}^{NS} p_s \cdot (1 + \gamma_s) \cdot \left[\begin{array}{l} \rho g_{ts} \cdot P_{hts} + \rho sr_{ts} \cdot SR_{hts} \\ + \rho or_{ts} \cdot OR_{hts} \\ + SU_{ht} + SD_{ht} \end{array} \right] \right\}, \forall l \quad (37)$$

A4. Pumped-storage subproblems for each unit

The pumped-storage hydro unit subproblem is given as

$$\min \left\{ \sum_{t=1}^{NT} \sum_{s=1}^{NS} p_s \cdot (1 + \gamma_s) \cdot \left[\begin{array}{l} \rho g_{ks} \cdot P_{kts} + \rho sr_{ts} \cdot SR_{kts} \\ + \rho or_{ts} \cdot OR_{kts} \\ + SU_{kt} + SD_{kt} \end{array} \right] \right\}, \forall k \quad (38)$$

A5. NG subproblems for each unit

The NG infrastructure constraints are coupling constraints that are relaxed by applying the Lagrangian relaxation method. The subproblems for NG units are given in (39), which are further decomposed into subproblems for each NG unit in (40). In (39), the first term is the expected revenue of selling energy and ancillary services minus the startup and shutdown costs for NG units. The second and third terms are the cost of NG usage from contracts and the NG withdraw from storage facilities, respectively. The fourth to seventh terms represent plant (24), pipeline (26), subarea (28), and max contracts for NG usage constraints (7) and (8) respectively. The last three terms relax upper and lower volume limits (17) and final volume (19) for gas storage facilities, respectively. Emission allowance constraints may be relaxed similarly [18].

$$\begin{aligned} \min \left\{ \sum_{j=1}^{NNG} \sum_{t=1}^{NT} \sum_{s=1}^{NS} p_s \cdot (1 + \gamma_s) \cdot \left[\begin{array}{l} \rho g_{ts} \cdot P_{jts} + \rho sr_{ts} \cdot SR_{jts} \\ + \rho or_{ts} \cdot OR_{jts} \\ + SU_{jt} + SD_{jt} \end{array} \right] \right\} \\ + \sum_{m=1}^{NPP} \sum_{t=1}^{NT} \sum_{n \in SPP(m)} \sum_{j \in SCT(n)} \sum_{s=1}^{NS} p_s \cdot \rho_n \cdot F_{jnmts} \\ + \sum_{w=1}^{NGS} \sum_{t=1}^{NT} \sum_{j \in SST(w)} \sum_{s=1}^{NS} p_s \cdot \rho_w \cdot q_{jwts}^{out} \\ + \sum_{p=1}^{NPL} \sum_{s=1}^{NS} p_s \cdot \left\{ \lambda_{\max, ps} \cdot \left(\sum_{j \in SPL(p)} \sum_{t=1}^{NT} F_{jts} - F_{\max, p} \right) \right\} \\ + \sum_{m=1}^{NPP} \sum_{s=1}^{NS} p_s \cdot \left\{ \lambda_{\max, ms} \cdot \left(\sum_{n \in SPP(m)} \sum_{j \in SCT(n)} \sum_{t=1}^{NT} F_{jnmts} - F_{\max, m} \right) \right\} \\ + \sum_{r=1}^{NSA} \sum_{s=1}^{NS} p_s \cdot \left\{ \lambda_{\max, rs} \cdot \left(\sum_{j \in SSA(r)} \sum_{t=1}^{NT} F_{jts} - F_{\max, r} \right) \right\} \end{aligned}$$

$$\begin{aligned}
& + \sum_{m=1}^{NPP} \sum_{n \in SPP(m)} \sum_{s=1}^{NS} p_s \cdot \left\{ \lambda_{\max, ns} \cdot \left(\sum_{j \in SCT(n)} \sum_{t=1}^{NT} F_{jnmts} - F_{\max, n} \right) \right\} \\
& + \sum_{w=1}^{NGS} \sum_{s=1}^{NS} p_s \cdot \left\{ \lambda_{\max, ws} \cdot \left(\sum_{t=1}^{NT} V_{wts} - V_{\max, w} \right) \right\} \\
& - \sum_{w=1}^{NGS} \sum_{s=1}^{NS} p_s \cdot \left\{ \lambda_{\min, ws} \cdot \left(\sum_{t=1}^{NT} V_{wts} - V_{\min, w} \right) \right\} \\
& + \sum_{w=1}^{NGS} \sum_{s=1}^{NS} p_s \cdot \lambda_{NT, ws} \cdot (V_{wNTs} - V_{NT, w}) \} \quad (39) \\
& \text{Min} \left\{ \sum_{t=1}^{NT} \sum_{s=1}^{NS} \left[p_s \cdot (1 + \gamma_s) \cdot \left[-(\rho_{gts} \cdot P_{jts} + \rho_{srts} \cdot SR_{jts} + \rho_{orts} \cdot OR_{jts}) + SU_{jt} + SD_{jt} \right] \right] \right\} \\
& + \sum_{m=1}^{NPP} \sum_{t=1}^{NT} \sum_{n \in SPP(m)} \sum_{s=1}^{NS} p_s \cdot \rho_n \cdot F_{jnmts} + \sum_{w=1}^{NGS} \sum_{t=1}^{NT} \sum_{s=1}^{NS} p_s \cdot \rho_w \cdot q_{jwts}^{out} \\
& + \sum_{m=1}^{NPP} \sum_{s=1}^{NS} p_s \cdot \left\{ \lambda_{\max, ms} \cdot \left(\sum_{n \in SPP(m)} \sum_{t=1}^{NT} F_{jnmts} \right) \right\} \\
& + \sum_{m=1}^{NPP} \sum_{n \in SPP(m)} \sum_{s=1}^{NS} p_s \cdot \left\{ \lambda_{\max, ns} \cdot \left(\sum_{t=1}^{NT} F_{jnmts} \right) \right\} \\
& + \sum_{w=1}^{NGS} \sum_{s=1}^{NS} p_s \cdot \left\{ (\lambda_{\max, ws} - \lambda_{\min, ws}) \cdot \left(\sum_{t=1}^{NT} \sum_{\tau=1}^{t-1} (q_{jw\tau s}^{in} - q_{jw\tau s}^{out}) \right) \right\} \\
& + \sum_{w=1}^{NGS} \sum_{s=1}^{NS} p_s \cdot \left\{ \lambda_{NT, ws} \cdot \left(\sum_{\tau=1}^{NT-1} (q_{jw\tau s}^{in} - q_{jw\tau s}^{out}) \right) \right\} \} \quad (40)
\end{aligned}$$

B. Proposed Solution Steps

The algorithm flowchart is shown in Fig. 1. The subproblems for coal, NG, cascaded hydro, and pumped-storage hydro units are solved in parallel when the coupling risk constraint is relaxed. Each subproblem related to an individual unit is solved to maximize the expected payoff of all scenarios in the entire study horizon. For the NG unit

subproblem in particular, coupling constraints are checked for constraints on NG contracts, pipelines, plants, subareas, and gas storage. The Lagrange multipliers are updated using the subgradient method and iterations continue until the difference between the objective functions in two consecutive iterations is smaller than a predefined threshold and an optimal or suboptimal solution is reached. After the solution of individual unit subproblems, the risk is calculated. If the risk aversion limit is met, the optimal solution is calculated. Otherwise, the Lagrange multipliers γ_s is updated for the risk inequality constraint (30) and returned to recalculate individual unit subproblems. The risk Lagrange multipliers are initially set to zero for all scenarios and updated using the subgradient method afterwards [24].

The target risk and profit are essential factors, which could impact the convergence of the algorithm. A GENCO might calculate the factors based on the following steps:

1) The problem is solved by assuming an initial target profit and without considering risk constraints. The proposed algorithm would calculate the appropriate expected risk. Otherwise, go to step 2 if the risk is not within the GENCO's tolerance.

2) The proposed algorithm is implemented with risk constraints to calculate the optimum profit. If the target profit is too high and the target risk is not attainable, the GENCO would decrease its target profit and repeat this step.

IV. CASE STUDIES

A GENCO with 3 coal units, 12 NG units, 11 hydro units, and 3 pumped-storage units is considered to analyze the effect of NG constraints on the midterm hydrothermal scheduling problem. The scheduling horizon is one year with hourly intervals. The detailed generating unit data, market prices for energy and ancillary services are given in <http://motor.ece.iit.edu/data/NGInfraPBUC>.

Fig. 1. Flowchart of the midterm stochastic hydrothermal scheduling

We assume uniform market clearing prices (MCPs) for all units. Locational marginal prices (LMPs) can be incorporated similarly. The NG infrastructure feeding NG units is shown in Fig. 2. Zone 1 is considered as a subarea since it is far from the NG supply. The yearly NG usage limit for Zone 1 is 37,200 MMCF (subarea limit).

Fig. 2. NG units and infrastructure

In this study, NG storage facilities are not considered except in Case 4, where an NG storage facility with a capacity of 1,000 MMCF is located in Zone 3 for supplying NG units within Zone 3. The cost of utilizing the storage is \$2,170 per MMCF. NG contracts are shown in Table I. Pipeline 1 has one firm and one interruptible contract while Pipeline 2 has one interruptible contract. The yearly pipeline constraints are 155,000 and 90,000 MMCF for Pipelines 1 and 2, respectively.

TABLE I
NG CONTRACTS

Pipeline #	Contract #	Type	Amount (MMCF)	Cost or Price
1	1	Firm	36,000	\$70,200,000
1	2	Interruptible	117,500	\$2,170 / MMCF
2	3	Interruptible	88,400	\$2,100 / MMCF

The following four cases are considered:

Case 1: Base case without any NG constraints or supply interruptions

Case 2: Effect of NG infrastructure constraints

Case 3: Effect of NG supply interruptions

Case 4: Effect of NG storage facilities

These cases are discussed as follows.

Case 1: Base Case without any NG Constraints or Supply Interruptions:

This base case includes all the units but does not consider NG constraints or supply interruptions. This case is to be used as reference to show the effect of NG infrastructure and its interruptions in the following cases. The uncertainties in market price and natural water inflow are considered in the scenarios. The scenarios are reduced to 12 since the value of the objective function does not change much based on this number of scenarios [25]. The probability of each reduced scenario is given in Table II. A risk neutral model is considered first which aims to maximize the expected scenario payoffs. Scenarios 2 and 8 have lower payoffs as a function of market prices and natural water inflows. If the GENCO sets its target payoff at \$485,849,996, which is the expected payoff for the risk neutral case, the corresponding probability for the set of scenarios below the target payoff is 0.46 (i.e., $0.11 + 0.02 + 0.07 + 0.1 + 0.05 + 0.11$). The

expected downside risk is \$9,331,555. The expected downside risk would be decreased with the inclusion of risk constraints. Table III shows scenario payoffs for risk neutral and risk-constrained models (minimum risk). The downside risk is \$8,309,323 with the inclusion of risk constraints, which shows a 10.95% less risk than that of the risk neutral case. However, the expected payoff decreases by 0.3% in the risk-constrained case. This is the cost of risk aversion. Table IV shows the NG usage of different contracts for risk neutral and risk-constrained cases. The firm NG contract is fully utilized in both cases and the interruptible NG is consumed when market prices are high. The interruptible NG contract usage decreases in all scenarios with the introduction of risk constraints. This is because NG units are shut down in specific hours to reduce the downside risk.

TABLE II
PROBABILITY OF EACH SCENARIO AFTER SCENARIO REDUCTION

Scenario	1	2	3	4	5	6
Probability	0.07	0.11	0.02	0.07	0.08	0.08
Scenario	7	8	9	10	11	12
Probability	0.1	0.05	0.09	0.09	0.13	0.11

TABLE III CASE 1 PAYOFF

Scenario	Risk Neutral Payoff (\$)	Risk Constrained Payoff (\$)	Change (%)
1	496,829,660	492,811,146	-0.81
2	455,159,262	457,308,285	0.47
3	470,330,464	469,255,240	-0.23
4	478,319,870	481,583,723	0.68
5	486,346,522	485,826,120	-0.11
6	507,895,434	501,879,197	-1.18
7	468,243,935	471,056,266	0.60
8	460,055,586	461,652,104	0.35
9	488,026,721	485,933,588	-0.43
10	493,015,056	487,823,577	-1.05
11	531,379,691	523,638,213	-1.46
12	467,052,288	469,049,789	0.43
Expected Payoff (\$)	485,849,996	484,407,904	-0.30
Target (\$)	485,849,996		-
Downside Risk (\$)	9,331,555	8,309,323	-10.95

TABLE IV CASE 1 USAGE OF NG CONTRACTS

Scenario	Contract 1 NG (MMCF)		Contract 2 NG (MMCF)		Contract 3 NG (MMCF)	
	Risk Neutral Case	Risk Cons. Case	Risk Neutral Case	Risk Cons. Case	Risk Neutral Case	Risk Cons. Case
1	36,000	36,000	88,517	86,424	41,591	41,286
2	36,000	36,000	76,479	75,708	39,106	39,060
3	36,000	36,000	81,876	80,441	39,987	39,814
4	36,000	36,000	84,181	83,409	40,544	40,483
5	36,000	36,000	83,865	82,446	40,498	40,341
6	36,000	36,000	91,697	88,965	41,921	41,670
7	36,000	36,000	82,393	81,655	40,374	40,266
8	36,000	36,000	77,743	76,966	38,811	38,702
9	36,000	36,000	85,611	83,758	40,872	40,648
10	36,000	36,000	85,266	83,140	40,957	40,611
11	36,000	36,000	91,562	88,319	42,185	41,726
12	36,000	36,000	80,332	79,756	39,912	39,868
Exp. Value	36,000	36,000	84,429	82,827	40,661	40,462

Case 2: Effect of NG Infrastructure Constraints: All units and NG infrastructure constraints are used to show the effect of NG constraints on the midterm hydrothermal scheduling. These constraints, formulated in Section II, are on pipelines,

subareas, plants, and units. Table V shows scenario payoffs with risk neutral and risk-constrained model when considering NG infrastructure constraints. The downside risk is decreased by 11.96% against a drop in the expected payoff of 0.41%. When we adopt commitment decisions given in Case 1, the expected payoff changes to \$481,881,658. The difference in the expected payoff is \$282,486 (i.e., \$482,164,144 - \$481,881,658) which represents the cost of ignoring NG infrastructure constraints in decision-making.

TABLE V CASE 2 PAYOFF

Scenario	Risk Neutral Payoff (\$)	Risk Constrained Payoff (\$)	Change (%)
1	492,174,884	487,461,689	-0.96
2	452,984,686	455,218,835	0.49
3	467,379,771	466,489,686	-0.19
4	474,772,772	478,266,777	0.74
5	483,012,610	481,939,429	-0.22
6	502,690,545	494,945,756	-1.54
7	465,237,823	468,108,097	0.62
8	457,819,092	459,446,279	0.36
9	484,277,365	482,318,666	-0.40
10	489,136,100	482,952,060	-1.26
11	525,411,762	515,473,413	-1.89
12	464,728,792	466,871,393	0.46
Expected Payoff (\$)	482,164,144	480,180,559	-0.41
Target (\$)	482,164,144		-
Downside Risk (\$)	8,850,597	7,791,967	-11.96

TABLE VI
ZONE GAS USAGES OF UNITS IN CASE 1 AND CASE 2 (RISK NEUTRAL CASE)

Scenario	Zone 1 NG (MMCF)		Zone 2 NG (MMCF)		Zone 3 NG (MMCF)	
	Case 1	Case 2	Case 1	Case 2	Case 1	Case 2
1	60,283	37,045	64,234	64,234	41,591	41,591
2	53,100	37,162	59,379	59,379	39,106	39,106
3	55,156	37,073	62,720	62,720	39,987	39,987
4	56,927	37,037	63,253	63,253	40,544	40,544
5	56,237	37,181	63,628	63,628	40,498	40,498
6	60,820	37,075	66,877	66,877	41,921	41,921
7	55,605	37,092	62,788	62,788	40,374	40,374
8	52,262	36,957	61,482	61,482	38,811	38,811
9	57,384	37,103	64,227	64,227	40,872	40,872
10	57,848	37,169	63,418	63,418	40,957	40,957
11	61,340	37,188	66,222	66,222	42,185	42,185
12	53,967	37,136	62,365	62,365	39,912	39,912
Exp. Value	56,968	37,116	63,460	63,460	40,661	40,661

TABLE VII
CASE 2 EXPECTED USAGES FROM NG CONTRACTS

Contract 1 NG (MMCF)		Contract 2 NG (MMCF)		Contract 3 NG (MMCF)	
Risk Neutral	Risk Cons.	Risk Neutral	Risk Cons.	Risk Neutral	Risk Cons.
36,000	36,000	64,577	62,157	40,661	40,465

Therefore, the target payoff in this case should not be the same as that in the previous case when the NG infrastructure constraints were not considered. The GENCO would experience a lower payoff than its expectation if it does not update the target payoff. The value of the downside risk is \$8,850,597 for a target payoff \$481,881,658. If the GENCO sets its target payoff at \$485,849,996 as in Case 1, the probability for the set of scenarios below the target payoff would be 0.63 (i.e., $0.11 + 0.02 + 0.07 + 0.08 + 0.1 + 0.05 + 0.09 + 0.11$) with an expected downside risk of \$10,914,617. This indicates that ignoring NG constraints could affect the

GENCO's midterm schedule and increases the financial risk. Table VI shows the total NG usage of generating units located in Zone 1 for Cases 1 and 2. We observe that the subarea constraint would limit the NG usage of units in Zone 1 to slightly lower than the upper limit (37,200 MMCF) even though the higher gas utilization in Zone 1 would lead to a higher payoff. The generating units in Zones 2 and 3 are unaffected since their NG usage remains within limits. The decrease in scenario payoffs is due to NG subarea limits. The expected NG usages from contracts for risk neutral and risk-constrained cases are given in Table VII. When compared with the risk neutral case in Case 1, we see that the NG usage from the interruptible contract of Pipeline 1 has decreased by 19,582 (i.e., $84,429 - 64,577$) MMCF, which is due to binding subarea constraints in Zone 1. The units in Zone 1 would utilize the firm NG and the interruptible NG usage is limited by the subarea constraint. The interruptible contract in Pipeline 2 has not changed when compared to that in Case 1 since the midterm scheduling of units fed from Pipeline 2 does not violate the NG constraints.

It is cumbersome to represent the sensitivity of the risk with respect to the expected payoff analytically due to the complexity of the problem. Instead, the change of risk is evaluated for Case 2 by evaluating the minimum achievable risk at different target profits. The results are depicted in Fig. 3. The expected payoff for the risk neutral case was \$482,164,144 with a downside risk of \$8,850,597. The analysis for case 2 is repeated for the GENCO's target payoffs starting at \$460,000,000 to \$485,000,000 with a step of \$5,000,000. The points are connected with linear curves to obtain 5 linear segments. The slopes of the curve segments given in Fig. 3 is calculated as 0.16, 0.33, 0.40, 0.45 and 0.53 from segment 1 to segment 5 respectively. This shows that the rate of change in the lowest achievable risk increases as the GENCO increases its target profit. Consider that the GENCO has two different target profits namely \$460,000,000 and \$480,000,000 with lowest achievable risks 0 and \$6,730,647 respectively.

Fig. 3. Downside risk versus target payoff for Case 2

The \$1,000,000 of increase in target profit will result \$163,250 and \$529,779 of increase in lowest achievable risk respectively. Consequently, the extra risk exposition increases when the GENCO updates its target profits in the ascending direction. A similar analysis is trivial when the GENCO updates its target profit in the descending direction. Even though the downside risk was decreased by 11.96% with the consideration of risk constraints in Case 2, the GENCO would

have to update the target payoff to \$460,000,000 in order to reduce the risk to zero.

Case 3: Effect of NG Supply Interruptions: In this case, we study the effect of NG interruptions on the GENCO's payoff in a midterm scheduling. In severe weather conditions, the increasing NG demand for heating in residential areas is supplied by interruptible NG contracts. The interruption rate, which is defined as the ratio of the mean interruption time to the sum of mean interruption and mean available times [21], is taken as 0.1 for this case study and interruptions are simulated for the winter period. Table VIII depicts the scenario payoffs when considering NG interruptions and constraints for both risk neutral and risk-constrained conditions. If the GENCO determines a target payoff \$465,492,606 for the risk neutral case, the downside risk probability is 0.46 (i.e., $0.11 + 0.02 + 0.07 + 0.1 + 0.05 + 0.11$). The downside risk is \$8,469,522 and the expected payoff is decreased by \$16,671,538 (i.e., \$482,164,144 - \$465,492,606). This is the potential loss in the midterm stochastic hydrothermal scheduling due to NG interruptions. When compared with Case 1, the consideration of NG interruptions with NG infrastructure constraints further decreases the GENCO's expected payoff by \$20,357,390 (i.e., \$3,685,852-\$16,671,538). The amount of decrease could change with the rate of the NG interruptions. If the GENCO sets its target payoff to \$485,849,996 as in Case 1, the probability for the set of scenarios below the target payoff would be 0.87 (i.e., $0.07 + 0.11 + 0.02 + 0.07 + 0.08 + 0.08 + 0.1 + 0.05 + 0.09 + 0.09 + 0.11$) with an expected downside risk of \$23,126,635. This indicates that ignoring the NG network constraints could affect the GENCO's midterm schedule and further increases financial risks. With the consideration of risk constraints, the downside risk decreases by 12.19% against a drop in the expected payoff of 0.37%. Table IX gives the NG usage of gas contracts for each scenario for both risk neutral and risk considered cases. The NG contract utilization further decreases when compared with Case 2 due to NG interruptions. The NG usage does not decrease in Pipeline 1 with respect to Case 2 even if there are any NG interruptions. This is due to the fact that NG usage in Case 2 was already limited by subarea constraints and the unused gas at interrupted hours are shifted to other hours in Case 3. The decrease in gas usage from Contract 2 due to the interruptions is 10,575 MMCF (i.e., 40,661- 30,086).

TABLE VIII CASE 3 PAYOFF

Scenario	Risk Neutral Payoff (\$)	Risk Constrained Payoff (\$)	Change (%)
1	474,871,828	470,491,695	-0.92
2	437,655,315	439,855,079	0.50
3	451,281,020	450,284,507	-0.22
4	458,324,947	461,706,329	0.74
5	466,314,926	465,310,161	-0.22
6	484,836,849	477,901,647	-1.43
7	449,183,674	451,958,605	0.62
8	442,057,657	443,691,623	0.37
9	467,325,199	465,484,983	-0.39
10	472,370,528	466,607,116	-1.22
11	507,151,877	498,283,516	-1.75
12	448,957,954	451,049,157	0.47
Expected Payoff (\$)	465,492,606	463,761,550	-0.37

Target (\$)	465,492,606		-
Downside Risk (\$)	8,469,522	7,436,840	-12.19

TABLE IX
CASE 3 EXPECTED USAGES FROM NG CONTRACTS

Contract 1 NG (MMCF)		Contract 2 NG (MMCF)		Contract 3 NG (MMCF)	
Risk Neutral	Risk Cons.	Risk Neutral	Risk Cons.	Risk Neutral	Risk Cons.
36,000	36,000	64,577	62,550	30,086	29,975

Case 4: Effect of NG Storage Facility: This case includes all the units, NG infrastructure constraints, NG interruption cases, and NG storage facilities. NG can be stored for use at constrained hours. In this case, the NG storage in Zone 3 is considered. The storage is assumed to be full prior to the study period and NG injection to the storage by units is assumed to be zero at all periods (i.e., $q_{wts}^{\text{in}}=0, \forall t, \forall s$). Table X depicts the scenario payoffs for both risk neutral and risk-constrained cases. Table XI gives the expected usage of NG contracts under risk neutral and risk-constrained cases. Fig. 4 depicts the expected payoff against the NG storage size.

TABLE X CASE 4 PAYOFF

Scenario	Risk Neutral Payoff (\$)	Risk Constrained Payoff (\$)	Change (%)
1	489,727,434	486,554,727	-0.65
2	451,626,645	453,729,519	0.47
3	465,703,256	465,115,114	-0.13
4	472,760,956	475,928,829	0.67
5	480,924,774	481,293,666	0.08
6	499,767,150	493,687,013	-1.22
7	463,433,285	466,117,361	0.58
8	456,442,454	457,561,335	0.25
9	482,096,447	481,359,263	-0.15
10	486,971,597	481,762,048	-1.07
11	522,165,865	515,108,551	-1.35
12	463,117,388	464,735,786	0.35
Expected Payoff (\$)	480,028,588	478,840,621	-0.25
Target (\$)	480,028,588		-
Downside Risk (\$)	8,618,523	7,674,844	-10.95

TABLE XI
CASE 4 EXPECTED USAGES FROM NG CONTRACTS

Contract 1 NG (MMCF)		Contract 2 NG (MMCF)		Contract 3 NG (MMCF)	
Risk Neutral Case	Risk Cons. Case	Risk Neutral Case	Risk Cons. Case	Risk Neutral Case	Risk Cons. Case
36,000	36,000	64,577	63,577	30,977	30,763

Fig. 4. NG Storage Capacity versus Expected payoff, risk neutral case

When there is no storage, the expected payoff is \$465,492,606 as given in Case 3. The expected payoff is improved by 3.03% to \$480,028,588 for the first 1,000 MMCF storage. However, the improvement is only 0.09% with a payoff of \$480,456,556 for adding the second 1,000 MMCF of storage, and 0.08% with a payoff of \$480,841,268 for the third 1,000 MMCF of storage. This is because the GENCO would choose to burn NG from the storage at the most profitable hours. The payoff improvement for the first 1,000 MMCF storage is higher than the next 2,000 MMCF since the GENCO uses the first 1,000 MMCF of additional NG at most profitable hours. The expected payoff is could be improved significantly with the addition of 1,000 MMCF of NG storage when compared with the no-storage Case 3. The downside risk for this case has decreased by 10.95% against a drop in the expected payoff of 0.25% with the addition of risk constraints.

The four cases are summarized in Table XII. The GENCO's expected payoff decreases when considering NG constraints and interruptions. Furthermore, the expected financial downside risk and downside risk probability increase if the GENCO does not update its midterm target payoff and uses the target payoff determined in the base case for Cases 2 and 3. Thus, the GENCO could run a risk free case when considering NG constraints and interruptions and then determine a suitable target payoff and reduce the risk, which would lead to a more realistic risk-constrained midterm scheduling results. A reduction of 10,575 MMCF of NG was observed for Contract 3 in Case 3 as compared to Case 2 due to an NG interruption. The interruption resulted in an expected payoff reduction of \$16,671,538. However, the expected payoff increased to \$14,535,982 when a 1,000 MMCF NG storage was considered in Zone 3. In other words, 87.2% of the reduction in expected payoff, which was due to the NG interruption, was recovered with the addition of storage. The NG storage was 9% of the interrupted NG. In this case, the GENCO utilized the stored NG at most profitable hours. Tables XIII and XIV list the results of optimizing the individual types of units separately or together for risk neutral and risk-constrained cases, respectively.

TABLE XII
COMPARISON OF RESULTS OF CASES 1-4 WITH RISK NEUTRAL SOLUTIONS

	Case 1	Case 2	Case 3	Case 4
Expected Payoff (\$)	485,849,996	482,164,144	465,492,606	480,028,588
Downside Risk (\$)	9,331,555	10,914,617	23,126,635	12,028,208
Down. Risk Probability	0.46	0.63	0.87	0.63
Target (\$)	485,849,996			

TABLE XIII
COMPARISON OF RISK NEUTRAL CASES RESULTS

Cases	Expected Payoff (\$)	Downside Risk (\$)	Target (\$)
5: Coal Units Only	22,423,534	1,101,054	22,423,534
6: NG Units Only	140,688,206	4,396,534	140,688,206
7: Hydro Units Only	232,620,703	2,178,677	232,620,703
8: PS Units Only	69,760,163	995,095	69,760,163
Sum of Cases 5-8	465,492,606	8,671,360	465,492,606
9: All Units Together	465,492,606	8,469,522	465,492,606
Change (%)	0.00	2.33	0.00

TABLE XIV
COMPARISON OF RISK REDUCTION OF CASES

Cases	Expected Payoff (\$)	Downside Risk (\$)	Target (\$)
5: Coal Units Only	22,338,606	1,052,037	22,423,534
6: NG Units Only	140,117,126	4,231,735	140,688,206
7: Hydro Units Only	232,370,729	2,054,221	232,620,703
8: PS Units Only	69,464,139	551,639	69,760,163
Sum of Cases 5-8	464,290,600	7,889,632	465,492,606
9: All Units Together	463,761,550	7,436,840	465,492,606
Change (%)	0.11	5.74	0.00

The results of risk neutral case show that the scheduling of all units together with a target payoff that is equal to the sum of individual payoffs would result in a lower expected downside risk than the sum of those for individual risks. This could be explained by the fact that the variance of the sum of two normal distributed random variables is always less than or equal to the sum of their variances. Hence, a GENCO should determine a target by including all its units rather than considering them individually. For the risk-constrained case, the sum of lowest achievable risk for Case 3, which represents a combined solution of all generating units, is lower than the sum of separate downside risks of individual groups of units. The 5.75% improvement is because the consideration of all the units with a single total target payoff would provide more alternatives for risk reduction.

V. CONCLUSIONS

In this paper, the NG infrastructure constraints are incorporate into the GENCO's risk-constrained hydrothermal scheduling. Test results show that besides uncertainties in market prices and water inflow, GENCOs must further consider the NG infrastructure limitations in the optimal midterm scheduling. The NG storage facilities would improve the expected payoff of the GENCO against NG interruptions by providing NG at interrupted hours. The effect of utilizing the NG storage on the expected payoff is analyzed and it is observed that a considerable improvement in the expected payoff would be attainable even by a limited storage capacity in comparison with any NG interruptions. In addition, the solution for the optimization of the individual types of units separately is compared with that of all units together. It is observed that the solution of all units together would provide a better chance for any risk reductions.

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Hourly Scheduling of DC Transmission Lines in SCUC with Voltage Source Converters

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Abstract— This paper presents the modeling of high voltage direct current (DC) transmission systems with voltage source converters (VSCs) in security-constrained unit commitment (SCUC). The impact of VSC-DC transmission system on the economics and the security of integrated AC/DC transmission systems is discussed. The nonlinear AC/DC equations are linearized and the Newton-Raphson method is utilized to solve the linearized network in the base case and contingencies. The SCUC solution will determine the optimal hourly schedule of controllable VSC-DC transmission systems in electricity markets. Numerical examples show the efficiency of the proposed model.

Keywords: high voltage direct current transmission lines, voltage source converters, security-constrained unit commitment,

NOMENCLATURE

b	Index of AC buses
c	Superscript for contingency
NB	Number of AC buses
E_h	AC side voltage of the converter h
h	Index of DC converters
i	Index of units
t	Index of hour
inj	Superscript for an injection
$I_{dc,h}$	DC current of converter h
U_{it}	on/off state of generating unit i at time t
$\hat{U}_{it}, \hat{P}_{it}$	State and generation dispatch solution of unit i at time t
l	Index of lines
m	Index of AC bus terminals connected with converters
max, min	Subscript for maximum and minimum values
M_h	Modulation index of converter h
P_{it}	Generation dispatch of unit i at time t
P_h	DC active power through converter h
P_m	Withdrawal real power at ac bus m
$P_{term,h}$	Active power injected into the converter h
Q_h	DC reactive power through the converter h
Q_m	Withdrawal reactive power at AC bus m
$Q_{term,h}$	Reactive power injected into converter h
R_{dc}	Resistance of DC line
$SP1_b, SP2_b$	Slack variables for real power mismatch at bus b (≥ 0)

$SQ1_b, SQ2_b$	Slack variables for reactive power mismatch at bus b (≥ 0)
w	Objective of SCUC subproblem
X_h	Leakage reactance of coupling transformer connected to converter h
V_m	AC voltage at bus m
$V_{dc,h}$	DC voltage of converter h
ϕ_h	Power factor lagging/leading angle of converter h ($0 \leq \phi_h \leq \frac{\pi}{2}$ for rectifier, $-\frac{\pi}{2} \leq \phi_h \leq 0$ for inverter)
$\Delta P_m, \Delta Q_m$	Active and reactive power mismatch at ac bus m
$\Delta R1_h, \Delta R2_h, \Delta R3_h$	Mismatches of DC power flow equations related to converter h
Δ_i	Permissible real power adjustment for unit i
$\mathbf{A}$	Bus-unit incidence matrix
$\mathbf{G}_h$	Admittance matrix of DC network for converters h
$\mathbf{U}$	Generating unit state vector (0 or 1 values)
$\hat{\mathbf{U}}, \hat{\mathbf{P}}$	Generating unit state and economic dispatch solutions
$\mathbf{I}_{dc}, \Delta \mathbf{I}_{dc}$	Vector of DC current and its increment vector
$\mathbf{J1}, \mathbf{J2}, \mathbf{J3}, \mathbf{J4}, \mathbf{J5}, \mathbf{J6}$	Jacobian matrices
$\mathbf{M}, \Delta \mathbf{M}$	Modulation index vector and its increment vector
$\mathbf{M}_0$	Initial modulation index vector
$\mathbf{MP1}, \mathbf{MP2}, \mathbf{MQ1}, \mathbf{MQ2}$	Mismatch vectors
$\mathbf{P}, \mathbf{Q}$	Vector of real and reactive power generation of units
$\mathbf{V}, \mathbf{V}_{dc}$	AC and DC bus voltage vectors
$\mathbf{E}, \Delta \mathbf{E}$	Vector for AC side voltage of converters and its increment vectors
$\phi, \Delta \phi$	Power factor angle vector and its increment vector
$\delta, \Delta \delta$	Bus phase angle vector and its increment vector
$\mathbf{dP}_0$	Initial AC bus real power mismatch vector
$\mathbf{dQ}_0$	Initial AC bus reactive power mismatch vector
$\mathbf{dR1}_0, \mathbf{dR2}_0, \mathbf{dR3}_0$	Initial mismatch vectors of DC equations
$\pi, \psi, \bar{\psi}$	Simplex multipliers vectors
$\Delta \mathbf{PL}_{ac}, \Delta \mathbf{PL}_{dc}$	Vector of AC and DC line flow Increments
$\Delta \mathbf{T}$	Vector of transformer tap increment
$\Delta \gamma$	Vector of phase-shifter angle increment

I. INTRODUCTION

Modern power systems introduce VSC-DC transmission systems to enhance the operation and the flexibility of AC transmission systems in electricity markets. VSC-DC transmission systems use insulated gate bipolar transistors (IGBTs) for transmitting remote energy resources reliably and economically to load centers [1-3]. VSC-DC links use pulse

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width modulation (PWM) to set firing angles of IGBT switches in order to offer high speed controls.

In contrast to current source converter (CSC-DC) systems, VSC-DC transmission systems allow rapid and independent control of active and reactive power flows in all four quadrants by changing PWM firing patterns. VSC-DC transmission systems provide a full control to turn on/off IGBT switches for regulating DC voltages and power factors instantaneously and providing continuous and dynamic voltage regulations at AC transmission systems. Unlike CSCs, VSCs would not require active voltage commutations to switch off IGBTs, which enables them to feed isolated AC loads [4, 5]. Recently, VSC-DC taps were introduced to deliver energy to small loads located in the vicinity of DC lines [6, 7].

VSC-DC transmission systems were modeled as back-to-back links or similar configurations in power flow analyses [8-11]. Such studies utilized the Newton-Raphson method to solve nonlinear VSC-DC power flow equations. Two control actions, i.e., constant active power plus constant DC voltage (PV) and constant active power plus constant reactive power (PQ) were defined to maintain the secure operation of VSC-DC transmission systems. Also VSC-DC transmission constraints were included in the optimal power flow formulation by assuming that the total active power injection to a VSC-DC link was equal to power losses in the link.

In contrast to numerous publications on the modeling of phase shifters and FACTS devices in electricity markets [12-13], few studies investigated the optimal control of VSC-DC transmission systems in electricity markets. In this paper, we analyze the control and the scheduling of multi-terminal VSC-DC transmission systems and provide the optimal schedule for the control of VSC-DC transmission systems in the base case and contingencies.

We include the VSC-DC model in SCUC. As one of key tools for market clearing, the SCUC solution will provide the optimal hourly schedule of generating units and the optimal schedule of VSC-DC transmission systems for enhancing the security and economics. This paper uses sequential linear programming to find a feasible solution to the SCUC subproblem which may not guarantee a global optimal solution.

The rest of this paper is organized as follows. Section II discusses the DC modeling. The SCUC integrated with DC systems is presented in section III. The proposed model is tested with a 6-bus system and the IEEE 118-Bus system in section IV. We summarize our conclusion in section V.

II. VSC-DC MODEL

A. VSC-DC Transmission Model

We assume a balanced three phase conditions. In order to model the VSC h which is connected to the AC terminal's bus m , five variables including the direct voltage $V_{dc,h}$, direct current $I_{dc,h}$, converter AC voltage E_h , PWM modulation index M_h and the lagging/leading power factor angle ϕ_h , are defined in Fig. 1 [4]. E_h is controlled by adjusting M_h as

$$\begin{cases} E_h = \frac{M_h}{2\sqrt{2}} V_{dc,h} & \text{for rectifier} \\ E_h = -\frac{M_h}{2\sqrt{2}} V_{dc,h} & \text{for inverter} \end{cases} \quad (1)$$

where $0 \leq M_h \leq 1$. Also $P_{term,h}$ is controlled by adjusting ϕ_h ,

$$\begin{cases} P_{term,h} = \frac{V_m E_h \sin(\phi_h)}{X_h} & \text{for rectifier} \\ P_{term,h} = -\frac{V_m E_h \sin(\phi_h)}{X_h} & \text{for inverter} \end{cases} \quad (2)$$

where $0 \leq \phi_h \leq \frac{\pi}{2}$ for rectifiers and $-\frac{\pi}{2} \leq \phi_h \leq 0$ for inverters. Assuming converter transformers, valves, and DC capacitors are lossless, the active power converted into DC is

$$P_{term,h} = P_h = V_{dc,h} I_{dc,h} \quad (3)$$

Combining (1)-(3), we obtain the second converter equation as

$$\begin{cases} I_{dc,h} = \frac{M_h V_m \sin(\phi_h)}{2\sqrt{2} X_h} & \text{for rectifier} \\ I_{dc,h} = -\frac{M_h V_m \sin(\phi_h)}{2\sqrt{2} X_h} & \text{for inverter} \end{cases} \quad (4)$$

The VSC in Fig. 1 generates $-Q_h$, where

$$Q_h = -\frac{E_h (E_h - V_m \cos(\phi_h))}{X_h} \quad (5)$$

The reactive power flow from bus m to VSC-DC link is

$$Q_{term,h} = \frac{V_m (V_m - E_h \cos(\phi_h))}{X_h} \quad (6)$$

The difference between $Q_{term,h}$ and Q_h is the reactive power loss in the coupling transformer series reactance [14].

Fig 1. Schematic diagram of a VSC

B. DC Transmission Line Model

In this paper, we model two-terminal DC transmission systems based on the converter model presented in section III.A. However, mathematical derivations can be easily expanded to any DC configurations with any number of VSCs. In Fig. 2, two VSCs are connected to AC buses m_1 and m_2 via coupling transformers. We assume that the converter h_1 is a rectifier and converter h_2 operates as an inverter. Converters h_1 and h_2 are connected by a DC transmission line with a resistance R_{dc} . Here, (7) represents the model for a two-terminal DC configuration

$$\begin{bmatrix} I_{dc,h1} \\ I_{dc,h2} \end{bmatrix} = \begin{bmatrix} \frac{1}{R_{dc}} & \frac{1}{R_{dc}} \\ \frac{1}{R_{dc}} & \frac{1}{R_{dc}} \end{bmatrix} \begin{bmatrix} V_{dc,h1} \\ V_{dc,h2} \end{bmatrix} \quad (7)$$

For a multi-terminal DC system, the equation in matrix form is

$$\mathbf{I}_{dc} = \mathbf{G} \cdot \mathbf{V}_{dc} \quad (8)$$

Fig 2. Schematic of a two-terminal VSC-DC system

C. Control Modes of DC Transmission

DC links have two control modes including PV and PQ at their converter stations. In the PV control mode (9), VSC sets P_h and E_h at a specified level, while the PQ control mode (10) will keep a constant active power flow and reactive power flow. In each VSC-DC transmission link, at least one converter would operate in the PV mode to adjust DC voltages while others operate in PV or PQ mode.

$$P_h - P_h^{spec} = 0, \quad E_h - E_h^{spec} = 0 \quad (9)$$

$$P_h - P_h^{spec} = 0, \quad Q_h - Q_h^{spec} = 0 \quad (10)$$

The PV control is used in VSC-DC transmission links to secure the transfer of scheduled active power while maintaining AC voltages against possible disturbances. VSC-DC injects a specific amount of reactive power into the AC system for satisfying reactive power requirements and increasing the available transfer capacity (ATC) of AC system in the PQ control mode. In this paper, we consider upper and lower limits of control variables for the optimal control of VSC-DC system in the SCUC solution.

A back-to-back VSC-DC link that connects two AC systems would have one station for both rectifier and inverter systems with a zero DC line resistance. In back-to-back VSC-DC systems, (11) and (12) will replace (3) and (8), respectively.

$$P_{h1} = P_{h2} \quad (11)$$

$$V_{dc,h1} = V_{dc,h2} \quad (12)$$

D. VSC-DC Power Flow Equations

The nodal power balance at bus m which is connected to converter h is given as

$$\Delta P_m = P_m^{inj} - P_m - P_{term,h} = 0 \quad (13)$$

$$\Delta Q_m = Q_m^{inj} - Q_m - Q_{term,h} = 0 \quad (14)$$

where, $P_{term,h} = V_{dc,h} I_{dc,h}$ and $Q_{term,h} = \frac{V_m(V_m - E_h \cos(\phi_h))}{X_h}$

The power flow in per-unit for converter h at the AC terminal bus m is given as

$$\begin{cases} \Delta R1_h = E_h - \frac{M_h}{2\sqrt{2}} V_{dc,h} = 0 & \text{for rectifier} \\ \Delta R1_h = E_h + \frac{M_h}{2\sqrt{2}} V_{dc,h} = 0 & \text{for inverter} \end{cases} \quad (15)$$

$$\begin{cases} \Delta R2_h = I_{dc,h} - \frac{M_h V_m \sin(\phi_h)}{2\sqrt{2} X_h} = 0 & \text{for rectifier} \\ \Delta R2_h = I_{dc,h} + \frac{M_h V_m \sin(\phi_h)}{2\sqrt{2} X_h} = 0 & \text{for inverter} \end{cases} \quad (16)$$

$$\Delta R3_h = f(\mathbf{V}_{dc}, \mathbf{I}_{dc,h}) = I_{dc,h} - \mathbf{G}_h \mathbf{V}_{dc} = 0 \quad (17)$$

III. VSC-DC SYSTEM IN SCUC

Fig. 3 depicts the market clearing algorithm based on SCUC with AC/DC network constraints where market participants in AC systems (i.e., generation companies and customers) submit bids to the independent system operator (ISO). At the same time, transmission companies collect and send AC/DC network data to the ISO. The ISO executes the SCUC to clear the market with AC/DC transmission systems [15] in the base case and contingencies.

Fig. 3. Market clearing model with AC/DC network constraints

A. SCUC Formulation

The SCUC with integrated AC/DC transmission systems is stated as the following nonlinear optimization problem:

$$\begin{aligned} \text{Min } & f(\mathbf{x}) \\ \text{s.t. } & \\ & \mathbf{g1}(\mathbf{x}) \leq \mathbf{b1} \\ & \mathbf{ge1}(\mathbf{x}) = \mathbf{be1} \\ & \mathbf{g2}(\mathbf{x}) \leq \mathbf{b2} \\ & \mathbf{ge2}(\mathbf{x}) = \mathbf{be2} \end{aligned} \quad (18)$$

Variable $\mathbf{x}$ represents the on/off status and economic dispatch (ED) of generating units, startup/shut down indicators, and AC/DC control and state variables. The objective is to minimize the operating cost including generation and startup/shutdown costs. In (18), the first set of inequality constraints, $\mathbf{g1}(\mathbf{x}) \leq \mathbf{b1}$, and equality constraints, $\mathbf{ge1}(\mathbf{x}) = \mathbf{be1}$, represents UC constraints including power balance, generating

unit capacity, system spinning and operating reserve requirements, ramping up/down limits, minimum up/down time limits, maximum number of simultaneous on/off's in a plant, maximum number of on/off's of a generating unit in a given period, fuel and multiple emission limits. The second set of inequality constraints, $g2(x) \leq b2$, and equality constraints $g2(x) = b2$, include

- AC/DC power flow equations
- Limits on AC/DC control variables including real and reactive power generations, controlled shunt capacitors, tap-changing and phase-shifting transformers, modulation index and converter transformer tap ratios
- AC/DC network security constraints including AC/DC transmission flow and bus voltage limits, and limits to DC currents, voltages and power of converters
- Time limited corrective controls of contingencies such as permissible real power adjustment

B. SCUC Subproblem Formulation in Base Case

DC transmission system constraints are included in the hourly AC/DC network check subproblem which minimizes the AC bus real and reactive power mismatch (19) based on the UC solution while satisfying network security constraints (20)-(35). In essence, AC/DC transmission violations appear as power mismatches at AC buses (20). The hourly subproblem (19)-(35) minimizes slack variables (MP_1, MP_2) and (MQ_1, MQ_2) which represent the amount of real and reactive power mismatch that should be added to corresponding buses to remove violations. (21) considers DC transmission flows. (22)-(35) represents limits on real and reactive power generations, real and reactive power withdrawals at AC converter terminals, AC and DC transmission flows, AC bus voltage magnitudes, transformer tap settings, phase shifter angles, DC converter voltages and currents, converter modulation index, AC converter voltages and power factor angles. The elements of Jacobian matrices **J1** - **J6** are calculated in the Appendix A.

$$\text{Min } w(\hat{U}, \hat{P}) = \sum_{b=1}^{NB} (MP_{1b} + MP_{2b}) + (MQ_{1b} + MQ_{2b}) \quad (19)$$

s.t.

$$\begin{bmatrix} A \cdot \Delta P \\ A \cdot \Delta Q \end{bmatrix} - [J1] \begin{bmatrix} \Delta \delta \\ \Delta V \\ \Delta T \\ \Delta \gamma \\ \Delta V_{dc} \\ \Delta I_{dc} \\ \Delta E \\ \Delta \phi \end{bmatrix} + \begin{bmatrix} MP1 \\ MQ1 \end{bmatrix} - \begin{bmatrix} MP2 \\ MQ2 \end{bmatrix} = \begin{bmatrix} dP_0 \\ dQ_0 \end{bmatrix} \quad (20)$$

$$- [J2] \begin{bmatrix} \Delta V \\ \Delta V_{dc} \\ \Delta I_{dc} \\ \Delta M \\ \Delta E \\ \Delta \phi \end{bmatrix} = \begin{bmatrix} dR1_0 \\ dR2_0 \\ dR3_0 \end{bmatrix} \quad (21)$$

$$\Delta P = 0 \quad \pi \quad (22)$$

$$\Delta Q_{\min} \leq \Delta Q \leq \Delta Q_{\max} \quad \underline{\psi}, \bar{\psi} \quad (23)$$

$$\Delta P_{dc, \min} \leq \Delta P_{dc} = [J3] \begin{bmatrix} \Delta V_{dc} \\ \Delta I_{dc} \end{bmatrix} \leq \Delta P_{dc, \max} \quad (24)$$

$$\Delta Q_{dc, \min} \leq \Delta Q_{dc} = [J4] \begin{bmatrix} \Delta V_{dc} \\ \Delta I_{dc} \\ \Delta \phi \end{bmatrix} \leq \Delta Q_{dc, \max} \quad (25)$$

$$\Delta PL_{ac, \min} \leq \Delta PL_{ac} = [J5] \begin{bmatrix} \Delta \delta \\ \Delta V \\ \Delta T \\ \Delta \gamma \end{bmatrix} \leq \Delta PL_{ac, \max} \quad (26)$$

$$\Delta PL_{dc, \min} \leq \Delta PL_{dc} = [J6] \begin{bmatrix} \Delta V_{dc} \\ \Delta I_{dc} \end{bmatrix} \leq \Delta PL_{dc, \max} \quad (27)$$

$$\Delta V_{\min} \leq \Delta V \leq \Delta V_{\max} \quad (28)$$

$$\Delta T_{\min} \leq \Delta T \leq \Delta T_{\max} \quad (29)$$

$$\Delta \gamma_{\min} \leq \Delta \gamma \leq \Delta \gamma_{\max} \quad (30)$$

$$\Delta V_{dc, \min} \leq \Delta V_{dc} \leq \Delta V_{dc, \max} \quad (31)$$

$$\Delta I_{dc, \min} \leq \Delta I_{dc} \leq \Delta I_{dc, \max} \quad (32)$$

$$\Delta M_{\min} \leq \Delta M \leq \Delta M_{\max} \quad (33)$$

$$\Delta E_{\min} \leq \Delta E \leq \Delta E_{\max} \quad (34)$$

$$\Delta \phi_{\min} \leq \Delta \phi \leq \Delta \phi_{\max} \quad (35)$$

The optimization of (19)-(35) is described as follows,

1. Initialize AC/DC state variables and settings. For example, $\delta = 0$ rad, $V = 1$ pu, $V_{dc} = \pm 1$ pu, $I_{dc} = 0$ amp, $M = 1$, $E = 1$ pu and $\phi = 0$ rad. Calculate corresponding Jacobian matrices **J1** - **J6**, initial AC bus mismatch vectors **dP**₀ and **dQ**₀, and initial DC power mismatch **dR1**₀, **dR2**₀, **dR3**₀ based on the given UC solution.
2. Use LP to minimize (19) and calculate changes in AC/DC state and control variables (i.e., $\Delta \delta$, ΔV , ΔT , $\Delta \gamma$, ΔV_{dc} , ΔI_{dc} , ΔM , ΔE and $\Delta \phi$).
3. Update state and control variables. Recalculate elements of Jacobian matrices and mismatch vectors.
4. Minimize (19) and calculate changes in AC/DC transmission system state and control variables. If the incremental change in objective values within the last two iterations is less than a specified tolerance (i.e., $dR1, dR2, dR3 \leq \epsilon$), the DC power flow has converged; stop the iterative process. Otherwise, go back to Step 3.

If $w(\hat{U}, \hat{P})$ is larger than zero, ED cannot provide a feasible power flow solution to satisfy AC/DC flow constraints. Hence, a Benders cut (36) will be formed and added to the next iteration of UC problem.

$$\begin{aligned} w(U, P) = w(\hat{U}, \hat{P}) + \sum_{i=1}^{NG} (\bar{\pi}_{it} - \underline{\pi}_{it})(P_{it} - \hat{P}_{it}) \\ + \sum_{i=1}^{NG} (\bar{\psi}_{it} Q_{\max, i} - \underline{\psi}_{it} Q_{\min, i})(U_{it} - \hat{U}_{it}) \leq 0 \end{aligned} \quad (36)$$

C. Corrective and Preventive Actions for Managing Contingencies

In each contingency, sufficient corrective and preventive actions are considered based on $|P_{it} - \hat{P}_{it}^0| \leq \Delta_i$ for managing AC/DC transmission violations [16]. Δ_i is equal to 1/6 of unit i hourly ramping which represents the physically accepted adjustment of generating unit in ten minutes. Corrective actions refer to the redispatch of generating units when satisfying transmission flow violations in real time. Preventive actions refer to day-ahead adjustments in the base case UC and ED when considering potential contingencies. Preventive actions cannot be implemented in real time when responding to power flow violations. The hourly AC/DC network check subproblem is formulated as

$$\text{Min } w^c(\hat{\mathbf{U}}, \hat{\mathbf{P}}) = \sum_{b=1}^{NB} (MP 1_b^c + MP 2_b^c + MQ 1_b^c + MQ 2_b^c) \quad (37)$$

$$\begin{bmatrix} \mathbf{A} \cdot \Delta \mathbf{P}^c \\ \mathbf{A} \cdot \Delta \mathbf{Q}^c \end{bmatrix} - [\mathbf{J1}] \begin{bmatrix} \Delta \delta^c \\ \Delta \mathbf{V}^c \\ \Delta \mathbf{T}^c \\ \Delta \gamma^c \\ \Delta \mathbf{V}_{dc}^c \\ \Delta \mathbf{I}_{dc}^c \\ \Delta \mathbf{E}^c \\ \Delta \Phi^c \end{bmatrix} + \begin{bmatrix} \mathbf{MP1}^c \\ \mathbf{MQ1}^c \end{bmatrix} - \begin{bmatrix} \mathbf{MP2}^c \\ \mathbf{MQ2}^c \end{bmatrix} = \begin{bmatrix} \mathbf{dP}^c_0 \\ \mathbf{dQ}^c_0 \end{bmatrix} \quad (38)$$

$$- [\mathbf{J2}] \begin{bmatrix} \Delta \mathbf{V}^c \\ \Delta \mathbf{V}_{dc}^c \\ \Delta \mathbf{I}_{dc}^c \\ \Delta \mathbf{M}^c \\ \Delta \mathbf{E}^c \\ \Delta \Phi^c \end{bmatrix} = \begin{bmatrix} \mathbf{dR1}^c \\ \mathbf{dR2}^c \\ \mathbf{dR3}^c \end{bmatrix} \quad (39)$$

$$|\mathbf{P}^c - \hat{\mathbf{P}}^0| \leq \Delta \quad \overline{\pi}^c, \underline{\pi}^c \quad (40)$$

$$\Delta \mathbf{Q}^c_{\min} \leq \Delta \mathbf{Q}^c \leq \Delta \mathbf{Q}^c_{\max} \quad \underline{\psi}^c, \overline{\psi}^c \quad (41)$$

$$\Delta \mathbf{P}^c_{dc, \min} \leq \Delta \mathbf{P}^c_{dc} \leq \Delta \mathbf{P}^c_{dc, \max} \quad (42)$$

$$\Delta \mathbf{Q}^c_{dc, \min} \leq \Delta \mathbf{Q}^c_{dc} \leq \Delta \mathbf{Q}^c_{dc, \max} \quad (43)$$

$$\Delta \mathbf{P}^c_{ac, \min} \leq \Delta \mathbf{P}^c_{ac} \leq \Delta \mathbf{P}^c_{ac, \max} \quad (44)$$

$$\Delta \mathbf{P}^c_{dc, \min} \leq \Delta \mathbf{P}^c_{dc} \leq \Delta \mathbf{P}^c_{dc, \max} \quad (45)$$

$$\Delta \mathbf{V}^c_{\min} \leq \Delta \mathbf{V}^c \leq \Delta \mathbf{V}^c_{\max} \quad (46)$$

$$\Delta \mathbf{T}^c_{\min} \leq \Delta \mathbf{T}^c \leq \Delta \mathbf{T}^c_{\max} \quad (47)$$

$$\Delta \gamma^c_{\min} \leq \Delta \gamma^c \leq \Delta \gamma^c_{\max} \quad (48)$$

$$\Delta \mathbf{V}^c_{dc, \min} \leq \Delta \mathbf{V}^c_{dc} \leq \Delta \mathbf{V}^c_{dc, \max} \quad (49)$$

$$\Delta \mathbf{I}^c_{dc, \min} \leq \Delta \mathbf{I}^c_{dc} \leq \Delta \mathbf{I}^c_{dc, \max} \quad (50)$$

$$\Delta \mathbf{M}^c_{\min} \leq \Delta \mathbf{M}^c \leq \Delta \mathbf{M}^c_{\max} \quad (51)$$

$$\Delta \mathbf{E}^c_{\min} \leq \Delta \mathbf{E}^c \leq \Delta \mathbf{E}^c_{\max} \quad (52)$$

$$\Delta \Phi^c_{\min} \leq \Delta \Phi^c \leq \Delta \Phi^c_{\max} \quad (53)$$

The objective function (37) is introduced for minimizing real and reactive power mismatches when calculating a converged

power flow solution subject to transmission flow and bus voltage limits. If $w^c(\hat{\mathbf{U}}, \hat{\mathbf{P}})$ is larger than zero, a Benders cut (54) for contingency c will be formed and added to UC for calculating the next iterative solution of master problem.

$$w^c(\hat{\mathbf{U}}, \hat{\mathbf{P}}) = \pi^c(\mathbf{P} - \hat{\mathbf{P}}^0) + \overline{\psi}^c \mathbf{Q}_{\max}(\mathbf{U} - \hat{\mathbf{U}}^0) - \underline{\psi}^c \mathbf{Q}_{\min}(\mathbf{U} - \hat{\mathbf{U}}^0) \leq 0 \quad (54)$$

IV. NUMERICAL EXAMPLES

We study a six bus system and a modified IEEE-118 bus system in the base case and contingencies.

A. Six-bus System

The six-bus system shown in Fig. 4 has three generating units, seven AC transmission lines, two transformers and three loads. The slack bus is bus 1.

Fig. 4. Schematic diagram of six-bus system

The system data are presented in Appendix B. The following seven cases are tested in which Case 0 is for the UC problem (Base Case), Cases 1-3 consider SCUC with network constraints, and Cases 4-6 evaluate contingencies.

Case 0: UC without transmission constraints

Case 1: SCUC with AC transmission constraints

Case 2: SCUC with AC/DC transmission constraints in which the AC line 1-2 is replaced with a VSC-DC transmission link

Case 3: SCUC with AC/DC transmission constraints in which the AC line 1-2 is replaced with a CSC-DC transmission link.

Case 4: SCUC for Case 1 when the possible outage of unit 3 (CTGU3) is considered (preventive contingency)

Case 5: SCUC for Case 2 when the possible outage of unit 3 (CTGU3) is considered (corrective contingency)

Case 6: SCUC for Case 3 when the possible outage of unit 3 (CTGU3) is considered (corrective contingency)

In each case, base case and contingencies are considered to evaluate the system security and economics in different operating conditions. The results are presented as follows.

Case 0: When transmission constraints are ignored, the cheapest unit 1 will pick up the hourly base load and the more expensive unit 2 will be committed at hours 11-22 to supply partial loads. In this case, the most expensive unit 3 is not committed. The hourly UC is shown in Table I with a daily operating cost of \$108,240.73.

Case 1: When AC transmission constraints are considered based on the UC solution in Case 0, we find power flow violations at hours 1 and 7-24. Accordingly, 19 Benders cuts at

violated hours are generated and added to the master problem for the next UC calculation. After four SCUC iterations, all violations are removed and the final UC results are shown in Table II in which the changes in comparison to Case 0 are presented in bold. Unit 2 was committed at hour 1, and though there is no violation at hour 2, unit 2 with a minimum on/off time of 2 hours will remain committed at hour 2. The total operating cost is \$118,856.15.

TABLE I
UC RESULTS IN CASE 0

Total Operation Cost = \$108240.73	
Unit	Hours (1-24)
1	111111111111111111111111
2	000000000001111111111100
3	000000000000000000000000

TABLE II
UC RESULTS IN CASE 1

Total Operation Cost = \$ 118856.15	
Unit	Hours (1-24)
1	111111111111111111111111
2	11 0000 1111 111111111111
3	0000000000 1111 1111111100

TABLE III
UC RESULTS IN CASE 2

Total Operation Cost = \$ 113678.76	
Unit	Hours (1-24)
1	111111111111111111111111
2	00 0000000 0000 11111111 1000
3	0000000000 1111 1111111100

Case 2: SCUC with AC/DC transmission constraints is calculated when the AC line 1-2 is replaced with a VSC-DC link with $R_{dc} = 0.005$ pu. We find power flow violations at hours 11-22 based on UC results in Case 0. Hence, 11 cuts are generated by (36) and added to the next UC calculation. All AC/DC violations are removed after three SCUC iterations. The final hourly UC is shown in Table III in which changes in comparison to Case 1 are presented in bold. In this case, the VSC-DC link transfers the additional generation of unit G1 from bus 1 to bus 2. For example, 141 MW flow on the DC transmission line 1-2 in this case is compared to 52.75 MW flow on the AC line 1-2 in Case 1 at hour 17. Consequently, the cheaper unit 1 generates 220 MW at peak hour 17 while it generated only 132.16 MW in Case 1. The expensive unit 2 is off at hours 1-2, 9-12 and 22-24 and the total operating cost is \$113,678.76 which is less than that in Case 1. Tables IV and V show the optimal operating points of rectifier and inverter over 24 hours, respectively. The optimal control strategy of DC transmission line is determined according to the values in Tables IV and V. For instance, based on control criteria presented in section III.C, at hour 21, the rectifier will have a PV control mode ($P = 141.46$ MW plus $V = 1.20$ pu) and the inverter will have a PQ control mode ($P = -140.76$ MW plus $Q = -70$ MVar). For a two-terminal VSC-DC system, at least one converter should maintain the DC voltage.

Case 3: In this case, the SCUC solution with AC/DC transmission constraints is calculated in which the AC line 1-2 is replaced with a CSC-DC transmission link shown in Fig. 5. α and T are the firing/extinction angle and the transformer

TABLE IV
RECTIFIER OPERATING POINT IN CASE 2

Hour	P_{term} (MW)	Q_{term} (MVAR)	V_{dc} (pu)	I_{dc} (pu)	M (pu)	E (pu)
1	100.91	-50.36	1.20	0.84	0.87	1.05
2	90.75	15.79	1.17	0.77	0.81	0.95
3	84.18	11.10	1.20	0.70	0.83	1.00
4	80.16	44.93	1.20	0.67	0.91	1.09
5	80.51	40.89	1.20	0.67	0.86	1.03
6	85.99	66.71	1.20	0.72	0.84	1.01
7	99.13	-55.69	1.16	0.85	0.90	1.05
8	103.32	-52.05	1.17	0.88	0.82	0.96
9	112.53	29.68	1.20	0.94	0.90	1.08
10	132.91	30.53	1.20	1.11	0.90	1.08
11	141.19	-31.28	1.16	1.22	0.85	0.98
12	141.28	-15.45	1.15	1.23	0.86	0.98
13	141.28	-52.82	1.20	1.18	0.85	1.02
14	141.34	-36.60	1.20	1.18	0.90	1.08
15	141.25	-36.07	1.20	1.18	0.92	1.11
16	141.26	-55.41	1.20	1.18	0.90	1.08
17	141.00	-55.45	1.20	1.18	0.90	1.08
18	141.03	-50.61	1.20	1.18	0.85	1.02
19	141.06	-40.97	1.17	1.20	0.84	0.99
20	141.19	-41.55	1.20	1.18	0.81	0.98
21	141.46	-41.56	1.20	1.18	0.81	0.98
22	141.88	6.97	1.17	1.21	0.83	0.97
23	121.77	41.63	1.20	1.01	0.87	1.05
24	121.41	1.39	1.20	1.01	0.91	1.09

TABLE V
INVERTER OPERATING STATUS IN CASE 2

Hour	P_{term} (MW)	Q_{term} (MVAR)	V_{dc} (pu)	I_{dc} (A)	M (pu)	E (pu)
1	-100.56	-20.63	-1.20	0.84	0.76	0.90
2	-90.45	-48.97	-1.17	0.77	0.80	0.94
3	-83.94	-63.26	-1.20	0.70	0.89	1.06
4	-79.93	-38.51	-1.20	0.67	0.90	1.08
5	-80.29	-41.14	-1.20	0.67	0.86	1.03
6	-85.73	-51.33	-1.20	0.72	0.87	1.04
7	-98.76	-18.95	-1.16	0.85	0.78	0.90
8	-102.93	-65.01	-1.17	0.88	0.84	0.99
9	-112.09	-53.62	-1.20	0.94	0.90	1.08
10	-132.30	-54.52	-1.19	1.11	0.89	1.06
11	-140.44	-70.00	-1.15	1.22	0.83	0.96
12	-140.52	-70.00	-1.14	1.23	0.84	0.96
13	-140.58	-70.00	-1.19	1.18	0.80	0.95
14	-140.65	-32.17	-1.19	1.18	0.77	0.92
15	-140.56	-70.00	-1.19	1.18	0.91	1.08
16	-140.57	-70.00	-1.19	1.18	0.87	1.04
17	-140.30	-70.00	-1.19	1.18	0.87	1.04
18	-140.34	-70.00	-1.19	1.18	0.80	0.96
19	-140.34	-70.00	-1.17	1.20	0.83	0.96
20	-140.50	-70.00	-1.19	1.18	0.81	0.96
21	-140.76	-70.00	-1.19	1.18	0.81	0.96
22	-141.14	-70.00	-1.17	1.21	0.82	0.96
23	-121.25	-58.17	-1.19	1.01	0.88	1.05
24	-120.90	-58.20	-1.19	1.01	0.91	1.09

Fig. 5. Schematic diagram of the two-terminal CSC-DC link

tap ratio of rectifier/inverter terminals respectively. Similar to the VSC-DC transmission system, the CSC-DC system can have full control over its real power transmission.

Tables VI and VII show the operating status of CSC-DC transmission system over 24 hours. Comparing Cases 2 and 3, we learn that VSC-DC and CSC-DC systems would change the direction of real power flow to mitigate congestions. Here, P_{term} in Tables IV and VI or Tables V and VII are quite similar. However, the CSC-DC transmission system consumes reactive power during the AC to DC power conversion (non-positive Q_{term} in Tables VI and VII). Since the corresponding voltage profile is degraded, we would create additional cuts for voltage violations. Here, generating unit 2 is committed at hours 1-12, 22-24 to supply the reactive power for keeping the AC voltage at bus 2 within its limits. Table VIII shows that the expensive unit 3 is not committed at these hours when generating units 1 and 2 with a minimum on time of 2 hours will satisfy network constraints at hours 11 and 22 (compared with UC results presented in Table III). The total operating cost is \$116,980.07 which is higher than that in Case 2.

TABLE VI
RECTIFIER OPERATION STATUS IN CASE 3

Hour	P_{term} (MW)	Q_{term} (MVAR)	V_{dc} (pu)	I_{dc} (A)	α (Deg)	T (pu)
1	93.84	23.52	1.17	257.25	4.04	1.10
2	85.30	20.68	1.13	242.87	2	1.06
3	82.32	21.39	1.08	244.54	4.31	1.08
4	74.93	19.65	0.99	243.54	2	1.01
5	74.59	18.00	1.06	225.37	2	1.05
6	80.05	18.73	1.13	228.23	2	1.06
7	94.04	23.10	1.17	257.92	2	1.10
8	99.09	25.17	1.17	272.46	2	1.10
9	108.22	28.46	1.18	293.43	2	1.12
10	96.99	24.28	1.17	266.14	2	1.10
11	81.64	18.72	1.16	226.59	2	1.08
12	94.33	23.13	1.17	257.86	2	1.10
13	88.77	21.16	1.17	244.18	2	1.10
14	87.30	20.64	1.17	240.43	2	1.09
15	82.97	19.13	1.16	229.45	2	1.09
16	78.02	17.46	1.15	217.00	2	1.08
17	77.83	17.41	1.15	216.61	2	1.08
18	84.65	19.70	1.16	233.62	2	1.09
19	85.29	19.94	1.16	235.36	2	1.09
20	93.20	22.72	1.17	255.03	2	1.10
21	93.24	22.74	1.17	255.13	2	1.10
22	77.60	17.35	1.15	216.19	2	1.08
23	54.03	10.19	1.10	157.07	2	1.05
24	103.83	26.89	1.18	283.64	2	1.11

Case 4: When the possible outage of unit 3 is considered (CTGU3), the UC results obtained in Case 1 for base case cannot supply the hourly load at hours 1-2 and 6-24. The hourly AC/DC network check subproblem solution presented in (37)-(53) generates Benders cuts related to existing violations for CTGU3. The final UC results presented in Table IX shows that this contingency is uncontrollable and preventive actions (i.e., additional commitment of unit 2 at hour 6) are necessary to maintain the system security in base case and contingency cases. In Table IX, commitment changes in comparison with Table II are shown in bold.

Case 5: Based on UC results obtained in Case 2, the system state can transfer to the base case by applying corrective actions (i.e., redispatch of units 1-2 and adjustments of phase-

shifter angles, transformers tap ratios, and VSC controls). The total operating cost increases to \$119456.27. In essence, \$119456.27-\$113678.76=\$5777.51 is the cost of maintaining the system security in the event of CTGU3.

TABLE VII
INVERTER OPERATION STATUS IN CASE 3

Hour	P_{term} (MW)	Q_{term} (MVAR)	V_{dc} (pu)	I_{dc} (A)	α (Deg)	T (pu)
1	-93.52	23.75	1.17	257.25	2	1.17
2	-85.01	21.33	1.12	242.87	2	1.13
3	-82.03	21.22	1.08	244.54	2	1.16
4	-74.64	20.23	0.98	243.54	2	1.06
5	-74.34	21.36	1.06	225.37	8.29	1.16
6	-79.80	24.49	1.12	228.23	10.54	1.14
7	-93.72	23.82	1.17	257.92	2	1.17
8	-98.73	26.08	1.16	272.46	2.26	1.17
9	-107.80	29.75	1.18	293.43	3.07	1.19
10	-96.64	25.31	1.17	266.14	2.95	1.19
11	-81.39	19.26	1.15	226.59	2	1.19
12	-94.01	23.87	1.17	257.86	2	1.19
13	-88.48	21.81	1.16	244.18	2	1.19
14	-87.02	21.26	1.16	240.43	2	1.19
15	-82.72	19.68	1.16	229.45	2	1.19
16	-77.79	17.95	1.15	217.00	2	1.19
17	-77.60	17.89	1.15	216.61	2	1.19
18	-84.39	20.28	1.16	233.62	2	1.19
19	-85.02	20.53	1.16	235.36	2	1.19
20	-92.89	23.44	1.17	255.03	2	1.19
21	-92.92	23.45	1.17	255.13	2	1.19
22	-77.37	17.83	1.15	216.19	2	1.19
23	-53.91	10.42	1.10	157.07	2	1.16
24	-103.44	28.42	1.17	283.64	4.3528	1.19

TABLE VIII
UC RESULTS IN CASE 3

Total Operation Cost = \$ 116980.07	
Unit	Hours (1-24)
1	1 1
2	1 1
3	0 0 0 0 0 0 0 0 0 0 0 0 1 1 1 1 1 1 1 1 1 1 0 0 0

TABLE IX
UC RESULTS IN CASE 4

Total Operation Cost = \$ 118856.15	
Unit	Hours (1-24)
1	1 1
2	1 1 0 0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1
3	0 0 0 0 0 0 0 0 0 0 0 1 1 1 1 1 1 1 1 1 1 1 0 0

Case 6: Based on the UC results in Case 3, the system state cannot be transferred to another base case state in the event of CTGU3. In other word, the system does not have a sufficient supply of reactive power for satisfying the hourly load while maintaining the system security. The system operator would resort to load shedding in the event of CTGU3 to find a SCUC solution. The provision of additional reactive power would guarantee a feasible SCUC solution.

B. IEEE-118 Bus System

A modified IEEE 118-bus system shown in Fig. 6 is tested. This system has 54 units, 186 branches, 14 capacitors, 9 tap-changing transformers and 91 demand sides. Zones 1 and 3 are connected by the AC tie line 23-24. Zones 2 and 3 are connected by AC tie lines 47-69, 49-69, and 65-68. In this example, we study the system performance for five cases. These cases include three zones which are operating

independently, interconnected with AC tie lines, or with VSC-DC lines. In each case, the system security is examined in different operating conditions. Furthermore, this example highlights the salient characteristics of VSC-DC transmission systems for enhancing the system security and economics. The 118-bus system data are given in <http://motor.ece.iit.edu/DC/VSC/IEEE118.xls>. The following cases are tested.

Case 0: UC for three separate zones (without flow constraints)

Case 1: UC for the entire system (without flow constraints)

Case 2: SCUC when three zones are connected by AC lines

Case 3: SCUC when three zones are connected by DC lines

Case 4: SCUC for Case 2 when the possible outage of unit 47 at Zone 2 is considered (preventive contingency)

Case 5: SCUC for Case 3 when the possible outage of unit 47 at Zone 2 is considered (corrective contingency)

Fig. 6. Schematic diagram of IEEE 118-bus system

The details are given as follows.

Case 0: Since the generation in Zone 1 is insufficient for supplying the load, the UC solution for this zone does not converge. In fact, Zone 1 imports power from the other two zones to supply its hourly load economically. The UC solutions converge in Zones 2 & 3 with a total operating cost of \$496,426.1 and \$659,534.06, respectively.

Case 1: In this case, the generation capacity in the 118-bus network is sufficient for supplying the hourly load. The final UC solution has a total operating cost of \$1,727,165.

Case 2: The UC solution in Case 1 are used to analyze SCUC using (19)-(35). Accordingly, certain transmission violations occur which include peak-hour reactive power shortages at buses 21, 41 and 86. These three buses are PQ buses that would need the additional reactive power supply to keep their bus voltages within acceptable limits. Consequently, more expensive units are committed which increase the operating cost to \$1,730,600.

Case 3: In this case, we replace AC tie lines with VSC-DC tie lines. We assume that converter terminals are similar to those listed in Table B.VI. Applying the UC results in Case 1, we

find that there are violations at hours 1-7, 10-11, 14-16, and 18-23. Consequently, Benders cuts are generated using (36) and a new UC solution is calculated. The total operating cost is \$1,728,242 that is less than that in Case 2. In this Case, the VSC-DC transmission system provides three additional degrees of flexibility (i.e., P, Q, and V) for security and economics. Consider AC and DC tie flows in Fig. 7 which represent the peak hour 17. The optimal loading will increase when the AC tie line 65-68 (in Case 2) is replaced with the DC tie line. The economical flows of other DC tie lines are adjusted similarly to minimize the total operating cost while enhancing the security margins in the base case. In other word, the DC control will optimize power exchanges among the three Zones. Table X compares the zonal operating costs at base case (Cases 0-3). Here, the operating costs in Zones 2&3 have increased in Case 3 as compared with that of Case 2; however, the total cost in this case is lower than that of Case 2 because of cost savings provided by Zone 1.

Fig. 7. AC flows (Case 2 on the left) and DC flows (Case 3 on the right)

TABLE X ZONAL OPERATING COSTS (BASE CASE)

	Zone 1 (\$)	Zone 2 (\$)	Zone 3 (\$)	Total (\$)
Case0	-	496,426.10	659,534.06	-
Case1	392,072.22	672,699.45	662,393.33	1,727,165.00
Case2	401,636.59	671,112.28	657,851.13	1,730,600.00
Case3	392,260.48	667,646.87	668,334.65	1,728,242.00

Case 4: When the possible outage of unit 47 is considered, the system state cannot be transferred to a new base case state by applying the UC solution in Case 2. Consequently, power flow violations appear and Benders cuts are generated to recalculate the UC solution in Case 2 (preventive actions). For instance, we observe that generating units 46 and 49 that were off in Case 2 are now committed to guarantee the system security. The difference in daily operation cost (i.e., \$1,743,653-\$1,730,600 = \$13,053) is the cost of preventive action for maintaining the security when the outage of generating unit 47 is considered.

Case 5: This is a controllable contingency whereby corrective actions (i.e., ED based on physical ramping) will mitigate transmission violations. The total operating cost is \$1,735,712 which is higher than that in Case 3.

V. CONCLUSIONS

A VSC-DC transmission system is integrated into SCUC which is solved by the Benders decomposition method. The efficiency of the proposed model is examined in the base case and in contingency cases. In addition, the comparison of VSC-DC and CSC-DC systems emphasizes that CSC-DC systems would require reactive power compensations at converter stations to guarantee the system security. The presented model will expand the security margin by introducing preventive and corrective actions and transferring the AC/DC contingency state to a new base case state in the event of outages. The VSC-DC transmission systems can successfully control active and reactive power flows, increase the transfer capability of AC transmission, mitigate AC flow congestions, decommit expensive generating units, and improve the operating costs in the base case and contingencies.

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VII. BIOGRAPHIES

Azim Lotfjou received his BS and MS in E.E. from Sharif University of Technology, Tehran, in 2001 and 2004, respectively. He completed his PhD degree in 2009 in the ECE Department at Illinois Institute of Technology.

Mohammad Shahidehpour (F'01) is Bodine Professor in the Electrical and Computer Engineering Department at Illinois Institute of Technology. He also serves as the Director of the Center for Electricity Innovation at IIT. He was the recipient of an honorary doctorate from the Polytechnic University of Bucharest in 2009.

Yong Fu (M'05) received his BS and MS in E.E. from Shanghai Jiaotong University, China, in 1997 and 2002, respectively and PhD degree in E.E. from Illinois Institute of Technology in 2006. Presently, he is an assistant professor in the ECE Department at Mississippi State University.

Appendix A: Jacobian Matrixes

The elements of Jacobian matrix $\mathbf{J}_1$ at the AC bus m connected to the DC converter h are formulated as

$$\frac{\partial \Delta P_{m,h}}{\partial V_{dc,h}} = -I_{dc,h} \quad (\text{A.1})$$

$$\frac{\partial \Delta P_{m,h}}{\partial I_{dc,h}} = -V_{dc,h} \quad (\text{A.2})$$

$$\frac{\partial \Delta Q_{m,h}}{\partial V_{m,h}} = -\frac{2V_{m,h} - E_h \cos(\phi_h)}{X_h} \quad (\text{A.3})$$

$$\frac{\partial \Delta Q_{m,h}}{\partial E_h} = \frac{V_{m,h} \cos(\phi_h)}{X_h} \quad (\text{A.4})$$

$$\frac{\partial \Delta Q_{m,h}}{\partial \phi_h} = -\frac{V_{m,h} E_h \sin(\phi_h)}{X_h} \quad (\text{A.5})$$

The elements of Jacobian matrix $\mathbf{J}_2$ at AC bus m connected to the DC converter h are formulated as

$$\frac{\partial \Delta R1_h}{\partial E_h} = 1 \quad (\text{A.6})$$

$$\frac{\partial \Delta R1_h}{\partial M_h} = \begin{cases} -\frac{V_{dc,h}}{2\sqrt{2}} & \text{for rectifier} \\ \frac{V_{dc,h}}{2\sqrt{2}} & \text{for inverter} \end{cases} \quad (\text{A.7})$$

$$\frac{\partial \Delta R1_h}{\partial V_{dc,h}} = \begin{cases} -\frac{M_h}{2\sqrt{2}} & \text{for rectifier} \\ \frac{M_h}{2\sqrt{2}} & \text{for inverter} \end{cases} \quad (\text{A.8})$$

$$\frac{\partial \Delta R2_h}{\partial I_{dc,h}} = 1 \quad (\text{A.9})$$

$$\frac{\partial \Delta R2_h}{\partial M_h} = \begin{cases} -\frac{V_{m,h} \sin(\phi_h)}{2\sqrt{2} X_h} & \text{for rectifier} \\ \frac{V_{m,h} \sin(\phi_h)}{2\sqrt{2} X_h} & \text{for inverter} \end{cases} \quad (\text{A.10})$$

$$\frac{\partial \Delta R 2_h}{\partial V_{m,h}} = \begin{cases} -\frac{M_h \sin(\phi_h)}{2\sqrt{2}X_h} & \text{for rectifier} \\ \frac{M_h \sin(\phi_h)}{2\sqrt{2}X_h} & \text{for inverter} \end{cases} \quad (\text{A.11})$$

$$\frac{\partial \Delta R 2_h}{\partial \phi_h} = \begin{cases} -\frac{M_h V_{m,h} \cos(\phi_h)}{2\sqrt{2}X_h} & \text{for rectifier} \\ \frac{M_h V_{m,h} \cos(\phi_h)}{2\sqrt{2}X_h} & \text{for inverter} \end{cases} \quad (\text{A.12})$$

The partial derivatives of $\Delta R 3_h$ will depend on the configuration of VSC-DC transmission system. For example, the partial derivatives of $\Delta R 3_1$ for the two-terminal DC transmission system shown in Fig. 2 are listed as

$$\frac{\partial \Delta R 3_1}{\partial I_{dc,1}} = 1, \quad \frac{\partial \Delta R 3_1}{\partial V_{dc,1}} = -\frac{1}{R_{dc}}, \quad \frac{\partial \Delta R 3_1}{\partial V_{dc,2}} = -\frac{1}{R_{dc}}$$

$$\frac{\partial \Delta R 3_2}{\partial I_{dc,2}} = 1, \quad \frac{\partial \Delta R 3_2}{\partial V_{dc,1}} = -\frac{1}{R_{dc}}, \quad \frac{\partial \Delta R 3_2}{\partial V_{dc,2}} = -\frac{1}{R_{dc}}$$

The elements of Jacobian matrix $\mathbf{A}_2$ and $\mathbf{B}_2$ for the DC converter v are formulated as

$$\frac{\partial \Delta P_h}{\partial V_{dc,h}} = -I_{dc,h} \quad (\text{A.13})$$

$$\frac{\partial \Delta P_h}{\partial I_{dc,h}} = -V_{dc,h} \quad (\text{A.14})$$

The elements of Jacobian matrix $\mathbf{A}_3$, $\mathbf{B}_3$ and $\mathbf{C}_3$ for the DC converter v are formulated as

$$\frac{\partial \Delta Q_h}{\partial V_{m,h}} = -\frac{E_h \cos(-\phi_h)}{X_h} \quad (\text{A.15})$$

$$\frac{\partial \Delta Q_h}{\partial E_h} = \frac{2E_h - V_h \cos(-\phi_h)}{X_h} \quad (\text{A.16})$$

$$\frac{\partial \Delta Q_{m,h}}{\partial \phi_h} = -\frac{E_h V_{m,h} \sin(-\phi_h)}{X_h} \quad (\text{A.17})$$

Appendix B: Network data for 6-Bus system

TABLE B.I

BUS DATA		
Bus No.	V _{Max} (pu)	V _{Min} (pu)
1	1.10	0.95
2, 3,4,5,6	1.15	0.90

TABLE B.II

TRANSMISSION LINE DATA

Line No.	From Bus	To Bus	R (pu)	X (pu)	Flow Limit (MW)
1	1	2	0.0050	0.170	150
2	1	4	0.0030	0.258	75
3	2	4	0.0070	0.197	100
4	5	6	0.0020	0.140	90
5	3	6	0.0005	0.018	90

TABLE B.III

TAP CHANGING TRANSFORMER DATA

Tap-Changing Transformers	From Bus	To Bus	X (pu)	Tap Max	Tap Min	Cap (MW)
T1	2	3	0.037	0.98	0.95	100
T2	4	5	0.037	0.98	0.95	90

TABLE B. IV
HOURLY LOAD

Hou r	Pd (MW)	Qd (MVAR)	Hour	Pd (MW)	Qd (MVAR)
1	175.19	50.28	13	242.18	69.51
2	165.15	47.40	14	243.60	69.91
3	158.67	45.54	15	248.86	71.42
4	154.73	44.41	16	255.79	73.41
5	155.06	44.50	17	256.00	73.47
6	160.48	46.06	18	246.74	70.81
7	173.39	49.76	19	245.97	70.59
8	177.60	50.97	20	237.35	68.12
9	186.81	53.61	21	237.31	68.11
10	206.96	59.40	22	232.67	66.78
11	228.61	65.61	23	195.93	56.23
12	236.10	67.76	24	195.60	56.14

TABLE B.V

GENERATOR DATA

U	Bus No.	Unit Cost Coefficients			Pmax (MW)	Pmin (MW)	Qmax (MVAR)
		A (MBtu)	b (MBtu/ MWh)	c (MBtu/MW ² h)			
G1	1	176.9	13.5	0.1	220	100	100
G2	2	176.9	17.6	0.1	100	10	50
G3	6	176.9	32.6	0.1	30	10	10

TABLE B.V

GENERATOR DATA (CONTUNIED)

Qmin (MVAR)	Ini. St. (h)	Min Down (h)	Min Up (h)	Ramp (MW/h)	Start Up (MBtu)	Fuel Price (\$/MBtu)
-100	4	4	4	55	100	1.2469
-40	2	2	3	50	200	1.2461
-10	1	1	1	20	0	1.2462

TABLE B.VI

CONVERTERS DATA FOR THE TWO-TERMINAL DC SYSTEM

Type	X (pu)	P _{min} (MW)	P _{max} (MW)	Q _{min} (MVAR)	Q _{max} (MVAR)
Rec.	0.02	0	150	-70	70
Inv.	0.02	0	150	-70	70

TABLE B.VI

CONVERTERS DATA FOR THE TWO-TERMINAL DC SYSTEM (CONTINUFES)

E _{min} (pu)	E _{max} (pu)	V _{dc, min} (pu)	V _{dc, max} (pu)
0.85	1.15	0.85	1.2
0.85	1.15	-1.2	-0.85

TABLE B.VII

STATIC LOAD DISTRIBUTION FACTORS

L1	L2	L3
0.1	0.2	0.2

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Application of augmented Lagrangian relaxation to coordinated scheduling of interdependent hydrothermal power and natural gas systems

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Abstract: This study proposes an optimisation model for the coordinated scheduling of interdependent electric power and natural gas transmission systems from a joint operator's viewpoint. The objective is to minimise the coordinated social cost while satisfying network and temporal constraints of the two interdependent systems. The joint operator will coordinate hourly schedules to supply natural gas to loads or generate electric power. The authors consider the application of Lagrangian relaxation (LR) or augmented LR to relax the coupling constraints of the two systems. The Lagrangian dual is decomposed into the security-constrained unit commitment subproblem with the hydro coordination and the natural gas allocation subproblem. The application of LR for solving the coordinated problem could cause oscillations in the dual solution which is due to the non-convex characteristics of the coordinated problem represented by integer variables and network constraints. Moreover, with slight changes in multiplier values, the linear cost function of the natural gas well may result in a cycling behaviour of the gas well output between its max and min limits. To avoid numerical oscillations and improve the solution quality, the augmented LR with a piecewise linear approximation of quadratic penalty terms and the block descent coordination technique are proposed. The authors consider the 6-bus with 7-node and the 118-bus with 14-node systems to verify that the applicability of the proposed method to the coordinated scheduling of electric power and natural gas transmission systems.

Nomenclature

Index

i, j	index of power unit
g_i	index of gas supplier including gas wells, storages and liquefied natural gas tanks
cm	index of compressor
el, gl	index of electricity load and residual gas load
t	index of hour
k	index of iteration
a, b	index of bus in power system

na, nb	index of node in gas network
l	index of branch in power system

Variables and functions

I	status indicator of generating unit
Y, Z	startup and shutdown indicator of unit
P	generation of unit
R	spinning reserve of unit
SU, SD	startup and shutdown cost of unit
$X_{it}^{on}, X_{it}^{off}$	up/down time of unit i at hour t

GI	status indicator of gas well	$T^{\text{on}}, T^{\text{off}}$	min on/off time of unit
GI°, GI^I	indicator of releasing status and charging status of storage	$P_{\min}, P_{\max}$	min/max capacity of a unit
GP	net output of gas well, storage	$GP_{\min}, GP_{\max}$	max/min net output of gas well and storage
GP°, GP^I	releasing and charging gas flow of storage	$PN_{\min}, PN_{\max}$	max/min pressure
$F_{\text{cc}}()$	unit's production cost function	$SV_{\max}, SV_{\min}$	upper/lower volume limit of hydro reservoir
$F_{\text{gc}}()$	gas supplier's production cost function	$HV_{\max}, HV_{\min}$	upper/lower volume limits of storage
$F_{\text{cf}}()$	natural gas consumption of gas-fired unit	$PR_{\min}, PR_{\max}$	max/min pressure ratio of compressor
$F_{\text{cf}}()$	natural gas consumption of compressor	$CH_{\min}, CH_{\max}$	max/min horsepower of compressor
$F_b()$	power-water discharge function	A	bus-generator incidence matrix
SV, HV	volume of gas storage and hydro reservoir	B	bus-electrical load incidence matrix
ELS, GLS	not served electricity and residual gas load	C	bus-branch incidence matrix
EL, GL	scheduled electricity and gas load	GA	node-gas supplier incidence matrix
Pf_l	power flow through branch l	GB	node-gas load incidence matrix
PN	pressure of node in gas system	GK	node-gas branch incidence matrix
$GF_{na nb}$	gas flow from node na to nb	GD	gas withdrawing node-compressor incidence matrix
CH	horsepower of compressor	GE	gas load-power unit index incidence matrix
γ	control angel of phase shifter		
θ	bus voltage angle		
q	water discharge of hydro unit		
s	spillage of hydro unit		
η	step size to update Lagrangian multiplier		
w	natural in flow to the reservoir of hydro unit		
λ	Lagrangian multiplier		
ω	penalty factor		
x, y	vector of variables in power system and natural gas system		
x_c, y_c	sub-vector of x, y representing variables in coupling constraints		
$e(x_c), g(y_c)$	functions in coupling constraints		

Constants

ρ	price of well-head of natural gas well, charging gas storage or releasing gas storage
σ	price of not served electricity and gas load
α, β	parameters of augmented LR
NT	scheduling period
RC	connection matrix for cascaded hydro reservoirs
x_{ab}	reactance between buses a and b
$PF_{l, \max}$	power flow limits of branch l
EL_D, GL_D	estimated electricity and residual gas load
R_D	required spinning reserve of system
P_{Loss}	power transmission loss
GU	set of gas-fired units
GS	set of gas storages
UR, DR	max ramp up/down rate

1 Introduction

In the last few decades, the number of gas-fired generating unit installations in the world has grown dramatically, which is mostly based on three reasons [1]. First, new combined-cycle gas units demonstrate higher economics over other fossil generating units. Second, gas-fired units have lower environmental impacts. Third, the rapid growth and the installation of volatile and intermittent renewable generating units in electric power systems would require additional generation reserves provided by fast response gas-fired units. According to statistics, the installed natural gas-fired generating capacity in ERCOT, Florida and ISO New England represented 60, 51 and 38% of the total generation capacity, respectively [1, 2]. In Europe and South America, natural gas-fired generation would also account for a considerable proportion of the total generation capacity. The electricity and gas infrastructures are highly interdependent. Accordingly, the security and economics of electric power systems are influenced by the economic allocation of natural gas resources as well as the secure operation of natural gas transmission systems. The natural gas transmission systems are also influenced by the hourly scheduling and the optimal operation of electric power systems.

In [3] the interdependency of gas and electricity was addressed. In [4] a generalised network flow model of the

US integrated energy system was proposed considering natural gas, coal and power infrastructures. In [5] a non-linear continuous optimisation model was proposed for a coordinated flow in electricity and natural gas infrastructures. The short-term operation planning of integrated natural gas and hydrothermal power systems with linear gas transmission constraints was considered in [6], where the unit commitment (UC) problem was solved by Lagrangian relaxation (LR) and dynamic programming methods. The impact of the natural gas transmission system on electric power markets was discussed in [7]. Our previous paper [8] presented a comprehensive scheduling model by incorporating non-linear natural gas transmission constraints and contracts. The natural gas usage limits of gas-fired generating units were implicitly determined by the feasible adjustment range of the natural gas network and priority orders of gas load contracts. The Benders decomposition was used to apply the hourly UC results to separate blocks of electric power and natural gas transmission constraints. However, our previous model considered the viewpoints of the ISO and vertically integrated utility operators. Furthermore, operating costs of compressors and natural gas wells, and residual gas load models were not directly considered in the objective function.

In this paper, we propose a coordinated scheduling model from a joint operator's viewpoint as shown in Fig. 1. The coordination model is a mixed-integer non-linear optimisation problem in which the objective function will minimise the social cost of electric power and natural gas systems. In our proposed model, the joint operator is an independent organisation, which could operate outside the traditional jurisdictions of gas and electric power operators and would pursue the overall interest of coordinated energy systems. Natural gas resources will be allocated optimally to either supply gas loads or gas-fired generating units. The two systems have a decomposable structure and we consider the LR method as the decomposition strategy of the coordination problem. The coupling constraints between the electric power system and the natural gas transmission system are relaxed by Lagrangian multipliers and dualised into the objective

function. The LR method is divided into two phases. The first phase is to solve the dual problem. However, the solution of phase one may not be feasible when considering the primal problem. Thus, the phase two of the dual problem will seek a feasible solution based on the solution of phase one as shown in Fig. 1. The relaxed primal problems are decomposed into security-constrained unit commitment subproblem with the hydro coordination (SCUC) and gas allocation subproblems that can be solved independently but in coordination. The methodologies for SCUC and natural gas allocation problems were developed in [9, 10], which incorporate the LR framework in our proposed model to solve the mixed-integer non-linear subproblems individually.

We demonstrate that the LR approach in our coordination model will not exhibit a satisfactory convergence. The non-convex characteristics of the coordinated problem will result in the oscillation of dual solution, which is due to integer variables and network constraints. Moreover, with slight changes in the multipliers, the linear cost function of the natural gas well may lead to a cycling behaviour of gas well output between its max and min values. Accordingly, the violation of relaxed constraints cannot be alleviated iteratively. Hence, the augmented LR method with piecewise linear approximation of quadratic penalty term is used for preventing numerical oscillations and improving the quality of dual solution. The Lagrangian dual will no longer be decomposable after introducing inseparable penalty terms. So we use the block descent coordination (BDC) technique to deal with this problem and solve the decomposed SCUC and gas allocation subproblems sequentially.

The rest of the paper is organised as follows. Section 2 proposes formulations of integrated scheduling model. Section 3 presents the LR and augmented LR-based methodology to implement coordination procedures. Numerical cases are studied in Section 4. The conclusion is drawn in Section 5.

2 Scheduling coordination model

2.1 Modelling outline

Our proposed model focuses on the steady-state analyses of the electricity and the natural gas systems. Both include integer variables with non-linear constraints. The outline of our proposed model is described as the following optimisation problem

Max Social welfare or Min Social cost

s.t.

- (a) Power balance and reserve requirements.
- (b) Individual generator constraints (including min on/off time, min/max generation capacity, startup/ shutdown characteristics, ramp rate limits, etc.).

Figure 1 Augmented LR-based electricity-gas scheduling coordination

- (c) Power transmission constraints.
- (d) Gas source limits and gas storage constraints.
- (e) Natural gas network constraints.
- (f) Electricity – gas coupling constraints.

The objective function is to minimise the social cost, which is the sum of electricity and natural gas operating costs over the scheduling period as shown in (1)

$$\text{Min}(\text{EC} + \text{GC}) \quad (1)$$

In our proposed model, natural gas-fired generating units will consider maintenance and crew costs and fuel costs will be managed by the joint operator. Therefore EC in (2) represents all operating costs of non-gas-fired units, electricity load-not-served penalty as well as non-fuel operating costs of gas-fired units.

$$\begin{aligned} \text{EC} = & \sum_t \left[\sum_{i \notin \text{GU}} F_{\text{cc},i}(P_{it}, I_{it}) + \text{SU}_{it} + \text{SD}_{it} \right] \\ & + \sum_t \sum_{\text{el}} \sigma_{\text{el}} \text{ELS}_{\text{el}t} \\ & + \sum_t \left[\sum_{i \in \text{GU}} F_{\text{cc},i}(P_{it}, I_{it}) + \text{SU}_{it} + \text{SD}_{it} \right] \quad (2) \end{aligned}$$

The fuel cost of natural gas-fired units, which depends on the individual unit consumptions, will be implicitly considered in the natural gas allocation cost (GC). GC is represented in (3), which includes operating costs of gas well, liquefied natural gas (LNG) and gas storage as well as penalty costs for the residual natural gas load-not-served. σ_{gl} is the penalty price corresponding to residual gas loads, indicating their incremental costs and priority orders.

$$\text{GC} = \sum_t \sum_{\text{gi}} F_{\text{gc},\text{gi}}(\cdot) + \sum_t \sum_{\text{gl} \notin \text{GU}} \sigma_{\text{gl}} \text{GLS}_{\text{gl}t} \quad (3)$$

The joint operator will coordinate the operation schedule to pursue the overall interests of coupled electricity and natural gas systems. The optimal allocation of natural gas to residual loads or gas-fired generating units is determined by market demands and relative incremental costs. For instance, joint operators will supply more natural gas to power plants, if the proposed supply of fuel to gas-fired generating units will result in the additional commitment of expensive generators. Also, higher penalty costs for not supplying the residual gas loads will lead to a larger supply of natural gas to such loads. Here, we may consider gas-fired units to provide a generation service to the coordinated electricity and natural gas systems while being compensated for their maintenance or crew costs. The joint operator will then perform a coordination of fuel consumption by electric and natural gas systems.

2.2 Power system constraints

1. Power balance and reserve constraint

$$\sum_i P_{it} I_{it} + \sum_{\text{el}} \text{ELS}_{\text{el}t} = \sum_{\text{el}} \text{EL}_{D,\text{el}t} + P_{\text{Loss},t} \quad (4)$$

$$\sum_i R_{it} I_{it} \geq R_D \quad (5)$$

2. Individual unit constraints

Min on/off time

$$[X_{i(t-1)}^{\text{on}} - T_i^{\text{on}}] [I_{i(t-1)} - I_{it}] \geq 0 \quad (6)$$

$$[X_{i(t-1)}^{\text{off}} - T_i^{\text{off}}] [I_{it} - I_{i(t-1)}] \geq 0 \quad (7)$$

Ramping rate limits

$$P_{it} - P_{i(t-1)} \leq Y_{it} P_{\min,i} + (1 - Y_{it}) \text{UR}_i \quad (8)$$

$$P_{i(t-1)} - P_{it} \leq Z_{it} P_{\min,i} + (1 - Z_{it}) \text{DR}_i \quad (9)$$

Max/Min power generation

$$P_{\min,i} I_{it} \leq P_{it} \leq P_{\max,i} I_{it} - R_{it} \quad (10)$$

A more detailed formulation of such constraints including emission and fuel constraints is given in [9]. Either a mode or a component model [1] may be used for the simulation of combined-cycle generating units.

3. Hydro unit and reservoir constraints

Power–water discharge conversion relationship

$$P_{it} = F_{h,i}(q_{it}, I_{it}) \quad (11)$$

Water discharge limits

$$q_{i,\min} I_{it} \leq q_{it} \leq q_{i,\max} I_{it} \quad (12)$$

Reservoir volume limits

$$\text{HV}_{i,\min} \leq \text{HV}_{it} \leq \text{HV}_{i,\max} \quad (13)$$

$$\text{HV}_{i,t=0} = \text{HV}_{0,i}, \quad \text{HV}_{i,t=\text{NT}} = \text{HV}_{\text{NT},i} \quad (14)$$

Water balance constraint for cascaded hydro units

$$\text{HV}_{it} = \text{HV}_{i,t-1} - q_{it} - s_{it} + w_{it} + \text{RC}_{ij} q_{j(t-\tau_j)} \quad (15)$$

where $q_{j(t-\tau_j)}$ represents the delayed water discharge to hydro unit i from other hydro units j .

4. Power transmission constraints

$$\begin{aligned} C \cdot PF &= A \cdot P - B \cdot (EL - ELS) \\ PF_l &= \frac{\theta_a - \theta_b - \gamma_{ab}}{x_{ab}} \quad (a, b \in l) \\ |PF_l| &\leq PF_{l, \max} \\ \gamma_{\min} &\leq \gamma \leq \gamma_{\max} \\ \theta_{\text{ref}} &= 0 \end{aligned} \quad (16)$$

2.3 Natural gas constraints

1. Gas well and storage constraints: The natural gas source is represented by gas well, gas storage and LNG tank, which demonstrate distinct prices and operating characteristics.

Cost of gas well is given as

$$F_{gc,gi}(\cdot) = \rho_{git} GP_{git}, \quad \forall gi \notin GS \quad (17)$$

Gas well and LNG source satisfy the following constraint

$$GI_{git} GP_{gi, \min} \leq GP_{git} \leq GI_{git} GP_{gi, \max}, \quad \forall gi \notin GS \quad (18)$$

Natural gas storage or LNG tank represents supplemental gas sources. The gas storage operation may switch among three exclusive modes, that is, releasing gas, charging gas and being off. When charging or releasing gas, additional operating costs will be considered as shown in (19)

$$F_{gc,gi}(\cdot) = \rho_{git}^I GP_{git}^I + \rho_{git}^O GP_{git}^O, \quad \forall gi \in GS \quad (19)$$

Max/Min flow rate while releasing or charging gas

$$GI_{git}^I GP_{gi, \min}^I \leq GP_{git}^I \leq GI_{git}^I GP_{gi, \max}^I, \quad \forall gi \in GS \quad (20)$$

$$GI_{git}^O \cdot GP_{gi, \min}^O \leq GP_{git}^O \leq GI_{git}^O \cdot GP_{gi, \max}^O, \quad \forall gi \in GS \quad (21)$$

Net output of gas storage is the difference between releasing and charging gas flow as shown in (22)

$$GP_{git}^O - GP_{git}^I = GP_{git}, \quad \forall gi \in GS \quad (22)$$

In addition, there is a volume balance constraint for each storage (e.g. hydro reservoir)

$$SV_{git} - SV_{gi(t+1)} = GP_{git}, \quad \forall gi \in GS \quad (23)$$

Volume of gas storage is restricted as

$$SV_{gi, \min} \leq SV_{git} \leq SV_{gi, \max}, \quad \forall gi \in GS \quad (24)$$

$$SV_{i,t=0} = SV_{0,i} \quad SV_{i,t=NT} = SV_{NT,i} \quad (25)$$

2. Gas transmission constraints: A steady-state gas transmission model is built based on the nodal gas mass balance, which indicates that the gas flow injected to a node is equal to the gas flow out of the node as shown in (27). The natural gas pressure associated with each node is satisfied within a reasonable range (28).

$$\begin{aligned} \sum_{gi} GA_{na,gi} GP_{gi} - \sum_{gl} GB_{na,gl} (GL_{gl} - GLS_{gl}) \\ - \sum_{nb} GK_{na,nb} GF_{nab} + \sum_{cm} GD_{na,cm} F_{nf,cm}(\cdot) = 0 \end{aligned} \quad (26)$$

The Weymouth equation [11] indicates the flow in a pipeline extending from gas node na to gas node nb is modelled as

$$GF_{nab} = \text{sgn}(PN_{na}, PN_{nb}) C_{mn} \sqrt{|PN_{na}^2 - PN_{nb}^2|} \quad (27)$$

$$PN_{\min, na} \leq PN_{na} \leq PN_{\max, na} \quad (28)$$

where C_{mn} is the pipeline constant that depends on temperature, length, diameter, friction and gas composition.

For driving the natural gas flow from providers to gas loads, compressors are built at intervals along the gas pipeline to compensate the pressure loss [5, 11]. The gas flow through centrifugal compressor is governed by (30)–(32)

$$GF_{nab} = \text{sgn}(PN_{na}, PN_{nb}) \cdot \frac{CH_{cm}}{k1_{cm} - k2_{cm} PR^{k3_{cm}}} \quad (29)$$

$$CH_{\min, cm} \leq CH_{cm} \leq CH_{\max, cm} \quad (30)$$

$$PR_{\min} \leq \frac{\max(PN_{na}, PN_{nb})}{\min(PN_{na}, PN_{nb})} \leq PR_{\max} \quad (31)$$

where $k1_{cm}$, $k2_{cm}$ and $k3_{cm}$ are empirical parameters corresponding to the compressor design.

2.4 Electricity–natural gas coupling constraints

A gas-fired power plant represents the linkage between natural gas and electricity systems. The gas consumption of a generation unit is a function of its hourly power generation stated as

$$GL_{gli} = \sum_i GE_{gli} F_{ef,i}(P_{it}, I_{it}), \quad \forall i \in GU \quad (32)$$

3 Solution of coordinated scheduling model

3.1 Coordinated scheduling by LR

We try the LR method first. A group of equations in (32) represents the electricity–gas coordination problem. The two systems have a decomposable structure and we consider the LR method as the decomposition strategy of the coordination problem (1)–(32). The LR method is divided into two phases as shown in Fig. 1. For the sake of clarity, in Section 3 we use vectors $\mathbf{x}$ and $\mathbf{y}$ to represent electricity and natural gas system variables, respectively. The coupling constraints are expressed as in (33) instead of (32), in which $\mathbf{x}_c$, $\mathbf{y}_c$ are subvectors of $\mathbf{x}$ and $\mathbf{y}$ for representing variables in coupling constraints.

$$\mathbf{e}(\mathbf{x}_c) - \mathbf{g}(\mathbf{y}_c) = 0 \quad (33)$$

In the Lagrangian function (34), the coupling constraints (33) are relaxed and incorporated into the objective function using the following Lagrangian multipliers

$$L(\mathbf{x}, \mathbf{y}, \boldsymbol{\lambda}) = EC(\mathbf{x}) + GC(\mathbf{y}) + \boldsymbol{\lambda}^T \mathbf{e}(\mathbf{x}_c) - \boldsymbol{\lambda}^T \mathbf{g}(\mathbf{y}_c) \quad (34)$$

The relaxed primal problem (35) is formulated in terms of minimising the Lagrangian function subject to constraints (4)–(32). In (35) $\phi(\boldsymbol{\lambda})$ is defined as the Lagrangian dual function with respect to $\boldsymbol{\lambda}$.

$$\phi(\boldsymbol{\lambda}) = \min_{\mathbf{x}, \mathbf{y}} \{L(\mathbf{x}, \mathbf{y}, \boldsymbol{\lambda}) | (4)–(31)\} \quad (35)$$

The resulting max–min problem is the following dual problem

$$\max_{\boldsymbol{\lambda}} \min_{\mathbf{x}, \mathbf{y}} \{L(\mathbf{x}, \mathbf{y}, \boldsymbol{\lambda}) | (4)–(31)\} \quad (36)$$

The difference between the optimal objective function values of primal and dual problems (36) is the duality gap.

For a given $\boldsymbol{\lambda}^{(k)}$, the Lagrangian dual (35) of the primal problem is decomposed into the independent SCUC and the gas allocation subproblems as shown in (37) and (38).

$$\min_{\mathbf{x}} \{EC(\mathbf{x}) + \boldsymbol{\lambda}^{(k)T} \mathbf{e}(\mathbf{x}_c) | (4)–(16)\} \quad (37)$$

$$\min_{\mathbf{y}} \{GC(\mathbf{y}) - \boldsymbol{\lambda}^{(k)T} \mathbf{g}(\mathbf{y}_c) | (17)–(31)\} \quad (38)$$

Since $\boldsymbol{\lambda}^{(k)}$ may not be the optimal solution of the dual problem (36), the dual cost $\phi(\boldsymbol{\lambda}^{(k)})$ resulted from the solution of subproblems (37) and (38) will produce a lower bound for the optimal solution of the dual problem (36). According to the weak duality theory, (39) is satisfied where $\mathbf{x}^*$, $\mathbf{y}^*$ is the optimal solution of primal problem and

$\boldsymbol{\lambda}^*$ is the optimal solution of the dual problem.

$$\phi(\boldsymbol{\lambda}^{(k)}) \leq \phi(\boldsymbol{\lambda}^*) \leq EC(\mathbf{x}^*) + GC(\mathbf{y}^*) \quad (39)$$

The phase one procedure of LR is to update Lagrangian multipliers $\boldsymbol{\lambda}$ and then solve the resulting small-scale optimisation problem (37), (38) iteratively. The dual cost would increase gradually until changes of $\boldsymbol{\lambda}$ or $\mathbf{x}_c$, $\mathbf{y}_c$ are relatively small. The Lagrangian multipliers would be updated in the direction of the dual cost increment. The subgradient method shown in (40) is the most popular one. The parameter $\eta^{(k)}$ in (40) represents the step size that would satisfy (41) for convergence [12, 13]. Since $\phi(\boldsymbol{\lambda}^*)$ is generally unknown before the dual problem is solved, we use the estimated value of $\phi(\boldsymbol{\lambda}^*) - \phi(\boldsymbol{\lambda}^{(k)})$.

$$\boldsymbol{\lambda}^{(k+1)} = \boldsymbol{\lambda}^{(k)} + \eta^{(k)} [\mathbf{e}(\mathbf{x}_c) - \mathbf{g}(\mathbf{y}_c)] \quad (40)$$

$$0 < \eta^{(k)} < \frac{\phi(\boldsymbol{\lambda}^*) - \phi(\boldsymbol{\lambda}^{(k)})}{\|\mathbf{e}(\mathbf{x}_c) - \mathbf{g}(\mathbf{y}_c)\|^2} \quad (41)$$

where $\|\cdot\|$ represents Euclidian norm.

3.2 Coordinated scheduling by augmented LR

The proposed LR method has demonstrated a few drawbacks as follows. The linear production cost function of gas well and piecewise linear generator production cost function will make the electricity and gas subproblems oscillate between maximum and minimum outputs. Moreover, non-convex characteristics of our coordination problem with integer variables and non-linear network constraints will create a large duality gap, which will make it difficult to find a good dual solution. Based on our experience, a good dual solution with a lower degree of violation will result in an optimal primal solution. Furthermore, the LR application in our case will cause oscillations in the solution of dual problem, which is due to the linearity of the price function of gas wells, storage and contracts. A similar phenomenon is recognised in the solution of hydrothermal coordination problem [14, 15]. In the following, the augmented LR is used that introduces penalty terms to smooth out the dual function and alleviate numerical oscillations. We relax the coupling constraint (33) in an augmented Lagrangian fashion in (42), where ω is a positive penalty factor.

$$A(\mathbf{x}, \mathbf{y}, \boldsymbol{\omega}, \boldsymbol{\lambda}) = EC(\mathbf{x}) + GC(\mathbf{y}) + \boldsymbol{\lambda}^T [\mathbf{e}(\mathbf{x}_c) - \mathbf{g}(\mathbf{y}_c)] + \omega \|\mathbf{e}(\mathbf{x}_c) - \mathbf{g}(\mathbf{y}_c)\|^2 \quad (42)$$

The augmented Lagrangian function (42) cannot be decomposed as it contains an inseparable cross penalty term, whose variables belong to both power and gas constraints. To make this term separable, [16] uses the auxiliary problem principle to linearise the penalty term.

An alternative is to use the BCD method, which is a non-linear Gauss–Seidel-type method [13]. The BCD would solve the subproblems (43) and (44) sequentially. Here, when minimising one of the subproblems, the coupling variables of the other one appears in an inseparable penalty term, which will be fixed based on the latest solution $\tilde{x}_c, \tilde{y}_c$ of subproblems. In this paper, BCD method is adopted.

$$\min_x \left\{ EC(x) + \lambda^{(k)T} e(x_c) + \frac{1}{2} \omega^{(k)} \|e(x_c) - g(\tilde{y}_c)\|^2 \right\} \quad (43)$$

such that (4)–(16)

$$\min_y \left\{ GC(y) - \lambda^{(k)T} g(y_c) + \frac{1}{2} \omega^{(k)} \|e(\tilde{x}_c) - g(y_c)\|^2 \right\} \quad (44)$$

such that (17)–(31)

This procedure may create high-order terms for subproblems (43) and (44). In this paper, a piecewise linear approximation with respect to quadratic penalty terms is used. The dual problem is formulated as

$$\phi_\omega(\lambda^*) = \max_{\lambda} \{ \min_{x,y} A(x, y, \omega, \lambda) \} \quad (44)$$

The updating of Lagrangian multipliers can still use (40). The iterative solution steps for the augmented LR-based coordination algorithm are discussed as follows:

1. Initiate the Lagrangian multipliers $\lambda^{(0)}$ and penalty factors $\omega^{(0)}, k = 0$.
2. For the given $\lambda^{(k)} \omega^{(k)} \tilde{y}_c$, solve the electricity subproblem (43). Update $\tilde{x}_c = x_c^{(k)}$.
3. Solve the gas subproblem (45) based on $\lambda^{(k)}, \omega^{(k)}$ and $\tilde{x}_c$. Update $\tilde{y}_c = y_c^{(k)}$.
4. Update the Lagrangian multipliers λ based on the subgradient method (40).
5. If $\|e(x_c^{(k)}) - g(y_c^{(k)})\| > \alpha \|e(x_c^{(k-1)}) - g(y_c^{(k-1)})\|$ Update $\omega^{(k+1)} = \beta \omega^{(k)}, \beta > 1$.
6. If $\|x_c^{(k)} - y_c^{(k)}\| \leq \varepsilon$, the final primal-dual solution is calculated as $(x^{(k)}, y^{(k)}, \lambda^{(k)})$. Otherwise, $k = k + 1$.
7. If the iteration number k is larger than the pre-specified number, go to step 8. Otherwise, go to step 2.
8. Construct the final feasible solution to the primal problem based on the obtained best solution to the dual problem.

3.3 Solution of SCUC and gas allocation subproblems

The common points of SCUC [9] and gas allocation [10] optimisation subproblems are represented by their types

Figure 2 Framework for the solution of SCUC/gas allocation subproblem

and structures. First, both are mixed-integer programming subproblems. Second, both have transmission network constraints and hold an L-shaped structure. For large-scale applications, the network security check is usually separated from the economic resource dispatch by either the Benders decomposition or the sensitivity analysis (i.e. power transfer distribution factor). The framework for the solution of SCUC or gas allocation subproblems is given in Fig. 2. More detailed formulations are provided in [8, 9]. The methodologies that may be engaged for the solution of SCUC or natural gas allocation subproblem do not change the overall framework of the proposed LR-based coordination strategy. Such methodologies can also be incorporated into our algorithm to solve the two subproblems [17, 18].

3.4 Calculation of feasible solution

In some cases, the convergence of dual problem is quick and fairly reliable, whereas in other cases the solution tends to exhibit a cycling behaviour, especially when using the LR approach. Usually, the iterative process is terminated after a pre-specified number of iterations. However, even the dual solution resulted from the last iteration may still be infeasible in the primal case, which is due to smaller violations of coupling constraints. Accordingly, we need to construct a feasible solution in the phase two of dual solution shown in Fig. 1. The feasible solution process could be heuristic or based on the approximate programming. In this paper, we adopt two steps to construct a feasible solution. First, based on the dual solution $\tilde{y}_c$, we solve the SCUC problem (46) to obtain the power system schedule x^* . In (46), $e(x_c) \leq g(\tilde{y}_c)$ represents energy constraints or gas usage limits of gas-fired generating units. Then, we obtain a feasible solution (x^*, y^*) by solving (47) based on the power system schedule x^* .

$$\begin{aligned} x^* &= \arg \min EC(x) \\ \text{such that (4)–(16)} \\ e(x_c) &\leq g(\tilde{y}_c) \end{aligned} \quad (45)$$

$$\begin{aligned} y^* &= \arg \min GC(y) \\ \text{such that (17)–(31)} \\ g(y_c) &= e(x_c^*) \end{aligned}$$

(46)

4 Case studies

In the 6-bus power system and the 7-node gas system, we mainly study the impact of gas storage and the network congestion on the coordinated scheduling results. The 118 bus with 14-nodes shows the impact of price incentives on the calculation of the least social cost and the coordinated schedule. The comparisons of augmented LR and LR methods are given in both cases.

Figure 3 Six-bus power system and 7-node natural gas system

Table 1 Parameters of gas well

Gas well	Node no.	Well-head price, \$/kcf	Min output, kcf/h	Max output, kcf/h
1	7	5.6	2000	5300
2	6	6	1000	6000

Table 4 Hourly commitments of Case 1 based on augmented LR

Unit	Hours (0–24)																							
1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
2	1	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	0	0	0
3	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	0	0

4.1 Six-bus power system and 7-node natural gas system

The 6-bus system and the 7-node natural gas system are depicted in Fig. 3. Parameters of the coupled power system and the natural gas system can be found in [8]. The cost information for the gas well and storage is given in Tables 1 and 2. Penalty prices for the electricity and the natural gas load not served are large as listed in Table 3. We apply the augmented LR and the LR methods to solve the following three cases.

Case 1: Base case without network or gas storage constraints

Case 2: Include network constraints

Case 3: Include network constraints and gas storage.

The augmented LR method is first applied to solve the three cases listed above. In Case 1, we ignore both electricity and natural gas transmission network constraints. Hence, there will be no congestion when scheduling the electricity and the natural gas systems. The hourly commitment of three gas-fired generating units is shown in Table 4. Fig. 4 shows the schedule of the gas well 2, which is the marginal gas well because of its higher well-head price. The social cost is \$1 322 422, which is the lowest of all three cases. In Case 2, we consider the electricity and the natural gas transmission network constraints. The flow limits on power transmission line and the pressure limits on gas nodes through pipelines will result in the commitment of expensive generating units at additional hours. In comparison with those in Table 4, Table 5 shows

Table 2 Parameters of gas storage in Case 3

Storage node no.	Gas injection cost, \$/kcf	Min. input, kcf/h	Max. input, kcf/h	Min. output, kcf/h	Max. output, kcf/h
1	2.5	150	2500	0	2000

Table 3 Electricity and gas load not served penalty price

penalty price electricity load not served (\$/MWh)	2000
penalty price of gas load not served (\$/kcf)	100

Figure 4 Gas well 2 in Cases 1, 2 and 3 based on augmented LR

that the unit 2 is committed at hours 10–11, 22, and the unit 3 is on at hours 8–9 and 23–24. Fig. 5 shows that the most efficient unit G1 would generate less in Case 2. The social cost is \$1 366 196, which is higher than that in Case 1. In Case 3, the simulation includes a gas storage, which draws natural gas from the pipeline into the gas reservoir at off-peak hours 2–7, and releases the natural gas during peak hours 8–24. The figure shows that by using the stored gas, the efficient generation unit 1 will generate more during hours 1–24. Table 6 shows the hourly schedule of generation units. The social cost is \$1 350 932, which includes the cost of gas well and the operation of gas storage.

We also solve the three cases by LR in order to compare the performances of the two methods. Table 7 shows the results. As presented in Section 3, using the LR algorithm will cause oscillations in the dual solution. A feasible solution based on the dual solution of LR by (45) will lead to electricity load shedding. The augmented LR algorithm, on the other hand, can avoid such oscillations and result in a better solution. To further illustrate the worst convergence of the dual problem by LR, the violation of constraints (32) against iterations is plotted in Fig. 6. The values of LR and augmented LR are shown in Fig. 7. Here, the violation of (32) is defined by the Manhattan norm $\|e(x_c) - g(y_c)\|_1$ of $e(x_c) - g(y_c)$. Obviously, the constraint violations cannot be mitigated in the LR method. However, the violations will approach zero by increasing the number of iterations in the augmented LR.

4.2 118-bus power system and 14-node natural gas system

The modified IEEE 118-bus power system has 54 fossil units, 12 gas-fired combined cycle units, 7 hydro units and 91 demand

Figure 5 Unit 1 dispatches in Cases 1, 2 and 3 based on augmented LR

sides. The natural gas transmission system is composed of 14 nodes, 12 pipelines and 2 compressors. The electricity and natural gas transmission system data are found in motor.ece.iit.edu/data/Gastranssmion_118_14test.xls. Table 8 lists the well-head prices of natural gas as well as the penalty price of residual natural gas loads not served. Table 9 shows the social costs.

Case 1: Base case solution: We solve the coordinated scheduling problem as formulated in this paper to obtain the least social cost schedules for coupled power and natural gas system. The daily social cost based on augmented LR in this case is \$2 350 957. Table 10 shows the daily generation and resource information. In addition, Fig. 8 shows the hourly generation for comparison. The congestion occurs in the 24-h gas transmission. The joint operators supply the residual gas loads 1–5 fully because of their higher penalty prices. However, the gas consumption of gas-fired units and residual gas loads 6–8 with lower priority are curtailed through optimisation iterations.

Case 2: Impact of penalty price of residual gas loads: We assume the penalty price of residual gas loads not served in Case 2 is decreased as shown in Table 10. The results show that residual gas loads can be interrupted or not supplied with a lower social cost as compared to Case 1. When considering the coordinated social cost, the joint operators would prefer to supply the additional natural gas to gas-fired units for power generation rather than supplying the residual gas loads. In other words, the social benefits of supplying gas-fired units are higher than providing the natural gas to residual gas loads. As shown in Table 10, the MWh generation fuelled by natural gas in Case 2 is higher than that in Case 1. The natural gas supplied to residual gas loads is reduced from 229 126 to 148 015 kcf in

Table 5 Hourly commitments of Case 2 based on augmented LR

Unit	Hours (0–24)																							
1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
2	1	0	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	0	0
3	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1

Table 6 Hourly commitments of Case 3 based on augmented LR

Unit	Hours (0–24)																							
1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
2	1	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	0	0	0	0
3	0	0	0	1	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0

Table 7 Comparison of augmented LR and standard LR based results

	Case index	Case 1	Case 2	Case 3
Augmented LR	dual cost (\$)	1 322 408	1 366 196	1 350 931
	violation degree (kcf)	2.3	3.1	3.6
	feasible social cost (\$)	1 322 422	1 366 196	1 350 932
	electricity load not served (MWh)	0	0	0
	gas load not served (kcf)	0	0	0
LR	dual cost (\$)	1 319 070	1 343 842	1 344 346
	violation degree (kcf)	14 642	12 162	12 491
	feasible cost (\$)	1 525 986	2 0743 44	1 935 640
	electricity load not served (MWh)	76.2	396.4	319.2
	gas load not served (kcf)	0	0	0

Figure 6 Gas storage volume and output based on augmented LR **Figure 7** Violation of dual iterations in Case 2**Table 8** Well-head prices and gas load price incentives in Cases 1–3

Price incentives	Case 1	Case 2	Case 3
gas well 1	0.95	0.95	1.66
gas well 2	0.90	0.90	1.58
gas well 3	1.00	1.00	1.75
penalty price of residual gas loads 1–3 not served	3.00	1.20	3.00
penalty price of residual gas loads 4–5 not served	2.50	1.10	2.50
penalty price of residual gas loads 6–8 not served	1.10	0.90	1.80

Case 1. The social cost in Case 2 is \$2 303 216. From Fig. 8, it is clear that the hourly coal generation in Case 1 is higher than that in Case 2.

Case 3: Impact of well-head price of natural gas: We increase the well-head price of natural gas wells by around 75% in comparison with that in Case 1 and solve the coordination scheduling problem by augmented LR. Table 10 shows that the power generation by natural gas in Case 1 is

Table 9 Social costs based on LT and augmented LR in Cases 1–3

Daily resources	Case 1	Case 2	Case 3	
social cost (\$)	augmented LR	2 350 957	2 303 216	2 710 834
	LR	2 424 892	2 384 547	2 823 916

Table 10 Summarised daily generation and resource based on augmented LR

Daily resources	Case 1	Case 2	Case 3
power generation by coal (MWh)	120 796	114 312	131 724
power generation by natural gas (MWh)	14 689	21 178	3783
hydro power generation (MWh)	8308	8302	8286
supplied gas to residual loads (kcf)	229 126	148 015	305 526
supplied gas to gas-fired units (kcf)	190 270	275 309	48 907
consumed gas by compressors (kcf)	6374	6472	6186

replaced largely by coal generation because of the soaring natural gas price. The natural gas is no longer an economic choice for electricity generation in comparison with coal. Fig. 8 shows that in Case 3, natural gas units generate less

than Case 1 and Case 2. Joint operators can dispatch more natural gas to residual gas loads. The daily social cost in Case 3 is \$27 10 834, which is much higher than that in Case 1.

The daily and hourly hydro generation quantities are close in the three cases. The differences arise because the optimisation process will coordinate water resources to generate more during peak load hours or avoid committing more coal or gas-fired units while satisfying the hydro reservoir constraints.

We also solve the base case and the other two cases by LR. The social costs are given in Table 9. We draw a conclusion that the LR algorithm would result in a more expensive solution, whereas the augmented LR algorithm can avoid oscillations and lead to less expensive solutions. The computing time for obtaining dual solution of the LR method in Case 1 is 485 s with 20 iterations, whereas that based on augmented LR is 330 s with 15 iterations. The augmented Lagrangian decomposition and coordination method avoids the solution oscillation difficulties and speeds up algorithm convergence, thus augmented LR can obtain the solution more quickly than LR.

Figure 8 Hourly generation composition based on augmented LR

5 Conclusions

This paper proposes a new model for the coordinated scheduling of the coupled electric power systems and natural gas transmission systems from a joint operator's viewpoint. The operator will coordinate the constrained resource scheduling and pursue the least social cost of energy system delivery. In this paper, the LR-based method is proposed initially to solve the problem. The augmented LR with the BDC technique is adopted to avoid numerical oscillations in this paper. Case studies verify that our proposed augmented LR method is effective in solving the coordinated energy scheduling model. Moreover, the augmented LR can avoid oscillations and improve the quality of the dual solution.

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Transmission Switching in Security-Constrained Unit Commitment

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Abstract—Transmission switching (TS) is introduced in security-constrained unit commitment (SCUC) for alleviating transmission violations and reducing operating costs. The SCUC problem is decomposed into the unit commitment (UC) master problem and the TS subproblem. The UC master problem finds the optimal hourly schedule of generating units. The TS subproblem uses this solution for transmission switching to find the optimal dispatch of units when considering network constraints. The TS subproblem also examines contingencies and identifies required changes to the UC master problem solution when contingencies cannot be mitigated in the TS subproblem. To propose a practical TS model, the standing phase angle difference limit is considered and relevant constraints are added to the TS subproblem. The case studies exhibit the effectiveness of the proposed approach.

Index Terms—Benders decomposition, mixed-integer programming (MIP), security-constrained unit commitment, transmission switching.

NOMENCLATURE

1) Indices:

b, m, n	Index for bus .
c	Index for contingency.
i	Index for unit.
l	Index for line.
ns	Index for nonswitchable lines.
s	Index for switchable lines.
t	Index for time.
$\wedge$	Index for given variables.

2) Sets:

L_b	Set of lines connected to bus b .
U_b	Set of units connected to bus b .

3) Parameters:

F_{ci}	Production cost function of unit i .
NB	Number of buses.
NC	Number of contingencies.
NL	Number of lines.

NG	Number of units.
NS	Number of switchable lines.
NNS	Number of nonswitchable lines.
NT	Number of time periods.
D_t	System demand at time t .
Pd_{bt}	Load at bus b at time t .
$P_{i,\min}$	Minimum power generation of unit i .
$P_{i,\max}$	Maximum power generation of unit i .
$PL_{l,\max}$	Maximum capacity of line l .
UX_{it}^c	State of unit i at time t in contingency c .
UY_{lt}^c	State of line l at time t in contingency c .
x_l	Reactance of line l .
Δ_l	Maximum standing phase angle difference of line l .

4) Variables:

I_{it}	Commitment state of unit i at time t .
P_{it}	Generation of unit i at time t .
PL_{lt}^{ns}	Power flow of nonswitchable line l at time t .
PL_{lt}^s	Power flow of switchable line l at time t .
$SL_{bt,1}, SL_{bt,2}$	Slack variables for power mismatch at bus b at time t .
v_t	Power mismatch at time t .
w_t^c	Power mismatch at time t and contingency c .
z_{lt}	Switching state of line l at time t .
π_{it}	Marginal change in violations with increase in unit i generation at time t .
δ_{mt}	Phase angle of bus m at time t .

I. INTRODUCTION

ONE of the approaches for mitigating transmission flow violations is to switch power system elements. Corrective transmission switching (TS) can provide economic benefits when compared with other control methods such as generation unit rescheduling or load shedding [1], [2]. In [3], TS was considered by applying current sources at certain bus terminals in

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Fig. 1. SCUC using TS.

the base network. The injected currents were represented as control variables in the optimal TS subproblem. In [4], TS was employed as a corrective action to mitigate contingencies. Also, TS was used to model outages in optimal power flow. In [5], a TS method was devised for calculating $N - 1$ secure states. A linear switching model was applied to model control actions applied to contingency constraints. In [6], TS was considered as a means of mitigating violations in transmission flows and bus voltages. Also, practical issues related to switching operations were addressed. In these papers, transformer tap adjustments and static VAR compensators were recognized as a means of controlling the voltage problems [6]. In [7], a TS algorithm was developed for switching off lines and buses to mitigate contingencies. This TS algorithm was based on a sparse inverse technique and fast decoupled power flow. Also in [8], TS provided system operators with a congestion management tool.

These works showed that TS provides flexible control actions for voltage stability, congestion management, loss reduction, and system security. However, TS can provide economic benefits, where this concept was first introduced in a pioneering work by O'Neill *et al.* [9] in a market context. Moreover in [10] and [11], the problem of finding an optimal generation dispatch and transmission topology was investigated. In [10], the TS problem was solved only for the base case dispatch of the system, while in [11], the $N - 1$ contingency criterion was considered as well. A mixed-integer programming (MIP) model was used, which employed binary variables to represent the transmission line state. These papers found that TS could achieve large improvements in dispatch costs. The work in [12] was an extension of [10] which demonstrated that market participants are subject to system uncertainties when considering TS. The paper discussed ways that topology changes could affect nodal prices, load payments, generation revenues, congestion costs, and flow-gate prices.

In this paper, the optimal TS for alleviating overloads is considered in SCUC that would take into account prevailing generating unit and transmission network constraints. Fig. 1 depicts the hierarchy for calculating SCUC by applying TS. The large-scale SCUC solution can represent a computation burden in power system operations. Since it is generally viewed as impractical to solve the generation unit and the entire set of network constraints together in SCUC, various decomposition approaches are considered by commercial SCUC packages.

The proposed decomposition applied to the SCUC problem in this paper consists of the UC master problem and the TS subproblem. Accordingly, Benders decomposition is utilized to

decompose the SCUC problem into smaller and easier to solve subproblems. Benders decomposition is mathematically sound and can easily be applied to large-scale systems. The optimality of Benders decomposition as well as its applicability to power system problems in practical cases are discussed in [13]–[17].

The UC master problem in Fig. 1 will find the optimal schedule of units, considering the prevailing UC constraints. The initial optimal schedule of generating units is obtained based on the available market data. The UC solution is used in the TS subproblem to find the optimal hourly dispatch of units, considering transmission constraints and the switching capability of transmission lines.

The TS subproblem in Fig. 1 consists of three main blocks as shown in Fig. 2. The TS Feasibility Check inspects the UC result to find whether a feasible TS solution can be found in the base case (without considering contingencies). If violations persist, Benders cuts are generated and added to the UC master problem. After satisfying the TS feasibility, the Optimal TS Scheduling block will utilize the UC solution to find the optimal dispatch of generating units and the state of switchable lines in the base case and contingencies. The Transmission Contingencies Check block will then examine the Optimal TS Scheduling results as to whether a converged dc power flow solution can be obtained. The Transmission Contingencies Check block will also adjust the transmission flows to mitigate any existing bus mismatches. In the case of violations, Benders cuts are formed and added to the Optimal TS Scheduling block for the redispatch of generating units.

If a converged dc power flow solution can be found for a contingency considered in the TS subproblem, this contingency will be labeled as controllable. However, if a converged dc power flow solution does not exist after a certain number of iterations between the Optimal TS Scheduling and the Transmission Contingencies Check blocks, i.e., the violations still persist in the Transmission Contingencies Check block, the considered contingency will be labeled as uncontrollable. The controllable contingencies would not require any further processing as they can be handled by the existing UC solution. The uncontrollable contingencies, which cannot be handled in the TS subproblem, are sent back to the UC master problem to find a new (preventive) UC schedule. By labeling the contingencies, the controllable ones are considered first (corrective) and then uncontrollable ones are handled (preventive). In other words, the proposed approach examines less expensive corrective actions before resorting to the more expensive preventive actions.

One of the concerns in performing the TS in successive hours is the possibility of excessive standing phase angle difference across a switched line. If a line closing causes a loop closure, rapid changes may be required in the generation dispatch, which could otherwise impact the generator shaft. The corresponding torque induced in the rotor of a generator could cause generator fatigue and equipment failure [18]–[20]. This may happen to any generators irrespective of their connectivity to the closed line. So, it is required to limit the standing phase angle difference to safeguard the rotor shaft. Usually a generation redispatch upon line closures would bring the standing phase angles back to the safe region. Different approaches are proposed to obtain the minimum generation redispatch needed to achieve

Fig. 2. Flowchart of SCUC using TS.

desired standing phase angles in a reasonable time [21]–[25]. This problem which is inevitable in restoration practices may also occur in the normal operation of power systems when attempting to reclose a single line that is a part of a transmission loop [20]. To present a practical TS model, the standing phase angle difference limit of switchable lines is formulated in our proposed model.

The rest of the paper is organized as follows. Section II presents the new proposed approach and formulates different parts of it. Section III conducts the numerical simulations and in detail discusses a six-bus system and the IEEE 118-bus system. Finally, concluding remarks are discussed in Section IV.

II. SCUC PROBLEM FORMULATION

The SCUC problem depicted in Fig. 2 is formulated as follows.

A. UC Master Problem (Optimal Hourly Schedule of Units)

The objective of the UC master problem is to determine the day-ahead schedule of generating units in order to minimize the system operating cost while satisfying the prevailing constraints. A complete list of UC constraints and optimization techniques is found in [13].

B. TS Subproblem

The TS subproblem consists of three parts, TS Feasibility Check, Optimal TS Scheduling, and Transmission Check as discussed below.

1) *TS Feasibility Check*: TS Feasibility Check which is a MIP problem would examine the possibility of a feasible TS solution. The objective is

$$\text{Min} \sum_{t=1}^{NT} \sum_{b=1}^{NB} (SL_{bt,1} + SL_{bt,2}). \quad (1)$$

The bus power mismatch is presented by (2), where $SL_{bt,1}$ and $SL_{bt,2}$ are surplus and deficit variables. The other constraints are power flow of switchable lines (3)–(6), power flow of nonswitchable lines (7)–(9), standing phase angle difference limits (10)–(11), and non-islanding constraint (12):

$$\sum_{i \in U_b} P_{it} - \sum_{l \in L_b} PL_{lt}^s - \sum_{l \in L_b} PL_{lt}^{ns} - P_{d_{bt}} + SL_{bt,1} - SL_{bt,2} = 0 \quad (2)$$

$$(b = 1, \dots, NB)(s = 1, \dots, NS)(n = 1, \dots, NNS) \\ PL_{lt}^s - (\delta_{mt} - \delta_{nt})/x_l + M(1 - z_{lt}) \geq 0 \quad (3)$$

$$(t = 1, \dots, NT)(l = 1, \dots, NL)(s = 1, \dots, NS) \\ PL_{lt}^s - (\delta_{mt} - \delta_{nt})/x_l - M(1 - z_{lt}) \leq 0 \quad (4)$$

$$(t = 1, \dots, NT)(l = 1, \dots, NL)(s = 1, \dots, NS) \\ PL_{lt}^s \leq PL_{l,\max} z_{lt} \quad (5)$$

$$(t = 1, \dots, NT)(l = 1, \dots, NL)(s = 1, \dots, NS) \\ -PL_{lt}^s \leq PL_{l,\max} z_{lt} \quad (6)$$

$$(t = 1, \dots, NT)(l = 1, \dots, NL)(s = 1, \dots, NS) \\ PL_{lt}^{ns} = (\delta_{mt} - \delta_{nt})/x_l \quad (7)$$

$$(t = 1, \dots, NT)(l = 1, \dots, NL)(ns = 1, \dots, NNS) \\ PL_{lt}^{ns} \leq PL_{l,\max} \quad (8)$$

$$(t = 1, \dots, NT)(l = 1, \dots, NL)(ns = 1, \dots, NNS) \\ -PL_{lt}^{ns} \leq PL_{l,\max} \quad (9)$$

$$(t = 1, \dots, NT)(l = 1, \dots, NL)(ns = 1, \dots, NNS) \\ \delta_{mt} - \delta_{nt} \leq \Delta_l + Mz_{l(t-1)} + M(1 - z_{lt}) \quad (10)$$

$$(t = 1, \dots, NT)(l = 1, \dots, NL) \\ \delta_{mt} - \delta_{nt} \geq -\Delta_l - Mz_{lt} - M(1 - z_{l(t-1)}) \quad (11)$$

$$(t = 1, \dots, NT)(l = 1, \dots, NL) \\ \sum_{l \in L_b} z_{lt} \geq 1 \quad (t = 1, \dots, NT) \quad (12)$$

where M is a large positive number.

The TS constraints use a single binary variable z_{lt} . When this variable is equal to one, power flow constraints on switchable lines will be the same as those of other lines. In such a case, the line will be treated the same as other lines. When the line's binary variable is zero, (3)–(6) would impose a zero line flow and the line would be switched off. The direction of transmission flow is from bus m to bus n . Constraints (10)–(11) consider the preset limits for the standing phase angle difference. The standing phase angle difference must be within its limits

before an attempt is made to close breakers. Using (10)–(11), standing phase angle difference limits are imposed when a line is switched on. Using (12), the islanding is prevented. This constraint guarantees that at least one line is connected to each bus when all corresponding lines are switchable.

If the TS Feasibility Check is infeasible, an LP problem is formed by setting the state of switchable lines to 1 and considering transmission constraints (2)–(9). This LP problem minimizes the bus power mismatches for 24 h and forms Benders cuts for the UC master problem. The LP problem applies the UC schedule using (13):

$$P_{it} = \hat{P}_{it}\hat{I}_{it} \leftrightarrow \pi_{it} \quad (i = 1, \dots, NG) \quad (13)$$

where $\hat{P}_{it}$ and $\hat{I}_{it}$ are fixed values calculated by the UC master problem. In (13), the arrow refers to the duality of the equality constraint, where π_{it} is the dual variable (also known as simplex multiplier) of equality constraint (13). Mathematically, this multiplier represents the marginal increment/decrement of the objective value when $\hat{P}_{it}\hat{I}_{it}$ is changed. To form the Benders cut, this dual variable is needed. The solution of the LP problem will provide the hourly cuts for the UC master problem stated as

$$\hat{v}_t + \sum_{i=1}^{NG} \pi_{it}(P_{it}I_{it} - \hat{P}_{it}\hat{I}_{it}) \leq 0. \quad (14)$$

In (14), the hourly bus power mismatch is noted as $\hat{v}_t$. The cut represents the coupled information on the unit generation dispatch and commitment state. The current violations can be mitigated by recalculating the hourly commitment states and the dispatch of generating units.

If the TS Feasibility Check solution is feasible, we will proceed to the Optimal TS Scheduling block as discussed next.

2) *Optimal TS Scheduling*: The Optimal TS Scheduling problem will calculate the optimal dispatch of generating units and the switchable line states in the base case and contingencies, given the hourly UC schedule

$$\text{Min} \sum_{i=1}^{NG} \sum_{t=1}^{NT} [F_{ci}(P_{it}^c)\hat{I}_{it}] \quad (15)$$

which is subject to unit and system constraints. The unit constraints include generation bids (prices), and power generation and ramp up/down rate limits. System constraints include power balance and spinning/operating reserve requirements, as well as fuel and emission constraints. A complete list of constraints can be found in [13]. The objective function (15) considers fixed unit commitment states which are calculated in the UC master problem. In the case of contingencies, the objective is also subject to load balance (16) and generation limit (17) constraints:

$$\sum_{i=1}^{NG} P_{it}^c = D_t \quad (t = 1, \dots, NT) \quad (16)$$

$$P_{i,\min}I_{it}UX_{it}^c \leq P_{it}^c \leq P_{i,\max}I_{it}UX_{it}^c \quad (t = 1, \dots, NT)(i = 1, \dots, NG) \quad (17)$$

where UX_{it}^c is the contingency state of unit i at time t in contingency c . Note that $c = 0$ represents base case. So, we would

have $UX_{it}^0 = 1$. In (16), the load balance equation is satisfied for each contingency. According to (17), when a unit is on outage (contingency), its generation would be zero.

The Optimal TS Scheduling is a MIP problem because of the binary states of switchable lines. At the first iteration, there are no constraints on line flows or switchable lines states. So, any values could be assigned to these variables. But in the subsequent iterations, the Benders cuts from the Transmission Contingencies Check establish constraints on switchable line states.

3) *Transmission Check in Contingencies*: The solution of the Optimal TS Scheduling block will be checked in the Transmission Contingencies Check as to whether a converged dc power flow solution can be obtained. So, we would have

$$\text{Min} w_t^c = \sum_{b=1}^{NB} (SL_{bt,1}^c + SL_{bt,2}^c). \quad (18)$$

This objective is subject to transmission security constraints (19)–(32):

$$P_{it}^c = \hat{P}_{it}^c \leftrightarrow \pi_{it}^c (i = 1, \dots, NG) \quad (19)$$

$$z_{lt}^c = \hat{z}_{lt}^c \leftrightarrow \mu_{lt}^c (l = 1, \dots, NL) \quad (20)$$

$$\sum_{i \in U_b} P_{it}^c - \sum_{l \in L_b} PL_{lt}^{sc} - \sum_{l \in L_b} PL_{lt}^{nsc} - P_{d_{bt}} + SL_{bt,1}^c - SL_{bt,2}^c = 0 \quad (21)$$

($b = 1, \dots, NB$)($s = 1, \dots, NS$)($ns = 1, \dots, NNS$)

$$PL_{lt}^{sc} - (\delta_{mt}^c - \delta_{nt}^c)/x_l + M(1 - z_{lt}^c) + M(1 - UY_{lt}^c) \geq 0 \quad (22)$$

($l = 1, \dots, NL$)($s = 1, \dots, NS$)

$$PL_{lt}^{sc} - (\delta_{mt}^c - \delta_{nt}^c)/x_l - M(1 - z_{lt}^c) - M(1 - UY_{lt}^c) \leq 0 \quad (23)$$

($l = 1, \dots, NL$)($s = 1, \dots, NS$)

$$PL_{lt}^{sc} \leq PL_{l,\max} z_{lt}^c UY_{lt}^c (l = 1, \dots, NL)(s = 1, \dots, NS) \quad (24)$$

$$- PL_{lt}^{sc} \leq PL_{l,\max} z_{lt}^c UY_{lt}^c (l = 1, \dots, NL)(s = 1, \dots, NS) \quad (25)$$

$$PL_{lt}^{nsc} - (\delta_{mt}^c - \delta_{nt}^c)/x_l + M(1 - UY_{lt}^c) \geq 0 \quad (26)$$

($l = 1, \dots, NL$)($ns = 1, \dots, NNS$)

$$PL_{lt}^{nsc} - (\delta_{mt}^c - \delta_{nt}^c)/x_l - M(1 - UY_{lt}^c) \leq 0 \quad (27)$$

($l = 1, \dots, NL$)($ns = 1, \dots, NNS$)

$$PL_{lt}^{nsc} \leq PL_{l,\max} UY_{lt}^c, (l = 1, \dots, NL)(ns = 1, \dots, NNS) \quad (28)$$

$$- PL_{lt}^{nsc} \leq PL_{l,\max} UY_{lt}^c (l = 1, \dots, NL)(ns = 1, \dots, NNS) \quad (29)$$

$$\delta_{mt}^c - \delta_{nt}^c \leq \Delta_t + Mz_{l(t-1)}^c + M(1 - z_{lt}^c) (l = 1, \dots, NL) \quad (30)$$

$$\delta_{mt}^c - \delta_{nt}^c \geq -\Delta_t - Mz_{l(t-1)}^c - M(1 - z_{lt}^c) (l = 1, \dots, NL) \quad (31)$$

$$\sum_{l \in L_b} z_{lt}^c \geq 1 (t = 1, \dots, NT) \quad (32)$$

where $\hat{P}_{it}^c$ and $\hat{z}_{it}^c$ are fixed values calculated by Optimal TS Scheduling. The power flow of switchable lines is obtained by (22)–(25). When a line is switched off, the line flow will be set to zero and removed from power flow equations. The power flow of nonswitchable lines is obtained by (26)–(29). In (22)–(29) the contingency state of line l at time t is considered by UY_{lt}^c . Note that $c = 0$ represents base case. Therefore, we would have $UY_{lt}^0 = 1$. Standing phase angle difference limits are considered by (30) and (31), and islanding is prevented using (32) for buses in which all corresponding lines are switchable. Here (30) and (31) use the given values of switchable states. So there is no time-based coupling in this problem.

If the total mismatch is zero, the proposed generation dispatch and switchable line schedule provide a feasible power flow solution which satisfies transmission security constraints. Otherwise, the Benders cut (33) will be added to the Optimal TS Scheduling block for mitigating the violations in the next iteration:

$$\hat{w}_t^c + \sum_{i=1}^{NG} \pi_{it}^c (P_{it}^c - \hat{P}_{it}^c) + \sum_{l=1}^{NL} \mu_{lt}^c (z_{lt}^c - \hat{z}_{lt}^c) \leq 0. \quad (33)$$

This cut represents the coupled information on the unit generation dispatch and switchable line schedule. If the current UC solution cannot mitigate the contingency c violations when the maximum number of iterations has reached, this contingency will be labeled as uncontrollable and the Benders cut (34) will be returned to the UC master problem for calculating a preventive generation schedule

$$\hat{w}_t^c + \sum_{i=1}^{NG} \pi_{it}^c (P_{it} I_{it} - \hat{P}_{it} \hat{I}_{it}) \leq 0. \quad (34)$$

The controllable contingencies are handled by corrective actions in the Transmission Contingencies Check without requiring any revisions to the existing UC solution. The proposed solution procedure is given as follows.

Step 1) Solve the UC master problem.

Step 2) Given the UC schedule, check the TS feasibility. If the TS is feasible, then proceed to Step 4.

Step 3) Minimize bus power mismatches if the TS Feasibility Check is infeasible. Form the Benders cuts and go to Step 1.

Step 4) Use the Optimal TS Scheduling to calculate the generation dispatch and the switchable line states in the base case and contingencies.

Step 5) Use the Transmission Check block to minimize bus power mismatches by utilizing the Optimal TS Scheduling results. If the mismatch is not zero, add the Benders cuts to the Optimal TS Scheduling for the next iteration. The controllable contingencies are handled by Transmission Check block. However, the Benders cut for uncontrollable contingencies are added to Step 1 for the next UC iteration. Stop the process if the total mismatch is zero.

III. NUMERICAL SIMULATIONS

Two case studies for the six-bus system and the IEEE 118-bus system are analyzed to illustrate the performance of the proposed method. The proposed method was implemented on a 2.4-GHz personal computer using CPLEX 11.0 [26].

Fig. 3. Six-bus system.

A. Six-Bus System

The six-bus system is shown in Fig. 3. The objective is to calculate the least cost of dispatch with an hourly fixed load. The characteristics of generators, lines, and the hourly load distribution over the 24-h horizon are given in Tables I–III, respectively. The load is distributed as 20%, 40%, and 40% among buses 3, 4, and 5, respectively. In Table I, the maximum sustained rate (MSR) and the quick start capability (QSC) of units are used to satisfy the reserve requirements of the system. The MSR and QSC are used to limit the spinning and operating reserves of the unit, respectively. The 10-min spinning reserve of a unit is the unloaded synchronized generation that can ramp up in 10 min. The spinning reserve of a unit cannot exceed the difference between its maximum capacity and current generation dispatch. This reserve is limited by the 10-min MSR. Operating reserve is the unloaded synchronized/unsynchronized generating capacity that can ramp up in 10 min. When a unit is on, its operating reserve is the same as spinning reserve. When a unit is off, its operating reserve is equal to its QSC. The following TS cases are considered:

Case 1: Base case UC (without contingencies)

Case 2: Outage of line 2–4 is considered in Case 1

Case 3: Outage of unit 2 is considered in Case 1

Case 4: Standing phase angle difference limits are considered in Case 1

The range of standing phase angle differences that a system can withstand mostly depends on the voltage level and is usually determined by steady-state and dynamic simulations. However in Cases 1, 2, and 3, it is assumed that the maximum standing phase angle is large enough to satisfy the associated constraints. In Case 4, the impact of standing phase angle difference on UC solution is examined.

Case 1: The UC with a subsequent dc network security check is used to find the results shown in Table IV. The cheaper unit 1 is on at all hours while unit 2 is used at peak hours to satisfy the remaining load and minimize the operating cost. Unit 2 is committed at hour 11 due to a load increase. The transmission network encounters flow violations on lines 1–4 and 4–5. Therefore, expensive unit 3 is turned on to help mitigate violations. Line 4–5 is congested at peak hours 15–19, which leads to a lower dispatch of unit 1 and a higher operating cost. The total operating cost is \$125 465.

The TS application will result in a similar schedule, but unit 3 is not committed in the entire scheduling horizon. This UC schedule will satisfy the TS feasibility check. So, the

TABLE I

Unit No.		1	2	3
Bus No.		1	2	6
Cost Coefficients	c (\$/MW ² h)	0.014	0.020	0.086
	b (\$/MWh)	19.96	23	29.14
	a (\$)	200	150	50
Minimum Capacity (MW)		100	10	10
Maximum Capacity (MW)		220	200	50
Startup Cost (\$)		50	40	0
Shutdown Cost(\$)		100	200	0
Minimum Up Time (h)		4	3	1
Minimum Down Time (h)		4	2	1
Ramp Up Rate (MW/h)		40	30	20
Ramp Down Rate (MW/h)		50	35	20
MSR (MW/min)		2	1.5	0.5
QSC (MW)		15	10	10
Initial Hour		+4	+3	+1
Initial Generation (MW)		140	20	10

TABLE II

Line No.	From Bus	To Bus	X (pu)	Flow limit (MW)
1	1	2	0.170	140
2	1	4	0.258	110
3	2	3	0.037	150
4	2	4	0.197	140
5	3	6	0.018	130
6	4	5	0.037	50
7	5	6	0.140	140

TABLE III

Hour	Load (MW)	Spinning Reserve (MW)	Operating Reserve (MW)
1	175.19	2.63	12.26
2	165.15	2.48	11.56
3	158.67	2.38	11.10
4	154.73	2.32	10.83
5	155.06	2.33	10.85
6	160.48	2.40	11.23
7	173.39	2.60	12.14
8	177.60	2.85	13.33
9	186.81	3.09	14.39
10	206.96	3.26	15.20
11	228.61	3.43	16.00
12	236.10	3.54	16.52
13	242.18	3.63	16.95
14	243.60	3.66	17.05
15	248.86	3.73	17.42
16	255.79	3.84	17.91
17	256.00	3.84	17.92
18	246.74	3.70	17.27
19	245.97	3.69	17.22
20	237.35	3.56	16.62
21	237.31	3.56	16.62
22	232.67	3.41	15.90
23	195.93	3.02	14.07
24	195.60	2.95	13.78

model would proceed to the Optimal TS Scheduling block. Imposing fewer cuts in this case would result in a cheaper UC solution. Using TS, the total operating cost is slightly dropped

TABLE IV

Unit	Hours (0-24)
1	1 1
2	1 0 0 0 0 0 0 0 0 0 0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 0
3	1 0 0 0 0 0 0 0 0 0 0 0 1 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0

TABLE V

Line	Hours (0-24)
2-4	- 1 1 1 1 1 1 0 0 0 0 0 0 0 0 1 1 0 0 0 0 0 0 0
4-5	- 1 1 1 1 1 1 0 0 0 0 0 0 0 0 1 1 0 0 0 0 0 0 0

to \$125 362. At hour 11 when lines 1–4 and 4–5 are congested, lines 2–4 and 4–5 are switched off instead of turning on unit 3. Here, there will be no transmission loop remaining in the system and the existing lines could increase the flows to their limits. Table V shows the state of switchable lines in which lines 2–4 and 4–5 are mostly switched off. At peak hours 16–17, the line flow constraints cannot be satisfied without placing back the lines 2–4 and 4–5. The standing phase angle differences for the two lines are 10.24 and 1.85 degrees, respectively.

Case 2: In this case, the outage of line 2–4 is considered. The UC in Case 1 cannot satisfy the dc network security check. The new UC is mostly the same as the schedule in Case 1, but unit 2 is committed at hours 10 and 24. This UC will mitigate the flow violations and satisfy the transmission security with a total operating cost of \$125 848. The UC solution given in Case 1 will satisfy the optimal TS scheduling block with line switching. The unit schedule is the same as that of Case 1. The TS schedule is different from that of Case 1, where line 4–5 is in service at peak hours 16–17 and off otherwise. The standing phase angle difference of line 4–5 at hour 16 is 0.3 degree. The line 2–4 contingency is handled with a corrective action at the Transmission Contingencies Check block. The congestion of line 1–2 is mitigated at peak hours 16–17 with a total operating cost of \$125 470 (i.e., 0.3% improvement)

Case 3: When unit 2 is on outage, unit 1 will not be able to satisfy the hourly load. Therefore, unit 3 is committed additionally. The preventive schedule without TS is shown in Table VI which is obtained with a more expensive daily operating cost of \$126 413. However, the proposed TS approach provides a preventive UC schedule. Comparing the new schedule with that of Table VI, we learn that the unit 2 is committed at hour 13 instead of hour 20, and unit 3 is not committed at hour 10. The flow violations at this hour are mitigated by switching off lines 2–4 and 4–5. The operating cost with TS is \$126 271. The state of switchable lines before outage of unit 2 is shown in Table VII. However, after the outage of unit 2, both switchable lines 2–4 and 4–5 will be switched off for the entire scheduling horizon.

In these three cases, all lines are considered as switchable. However, only lines 2-4 and 4-5 are switched in these cases. In Fig. 3, switching off any of lines 2-3, 3-6, 4-5, and 5-6 will remove the loop 2-3-4-5-6-2 with better results. Since line 4-5 has the lowest capacity, it is often subject to congestion which makes the line a good candidate for switching. This conclusion is consistent with the proposed results. By switching off line 4-5, the line flow in the loop, i.e., those of lines 2-3, 3-6,

TABLE VI
UC SCHEDULE OF SIX-BUS SYSTEM IN CASE 3 WITHOUT TS

[illegible]

TABLE VII
LINE SCHEDULE OF SIX-BUS SYSTEM IN CASE 3
USING TS BEFORE OUTAGE OF UNIT 2

Line	Hours (0-24)
2-4	- 1 1 1 1 1 1 1 1 1 1 1 1 1 1 0 1 1 1 1 1 1 1 1 0 1
4-5	- 0 0 0 0 0 0 0 0 0 0 1 0 1 1 0 1 1 1 1 1 1 1 1 1 0 0

and 5–6, can be raised without affecting the flow on other lines. Next, one of lines in the other loop, i.e., lines 1–2, 1–4, and 2–4, could be a good choice for switching. Since unit 1 is the most economical and the largest unit, it will remain in service along with the attached lines. So, line 2–4 would be the best TS choice for this loop. With switching off both lines 2–4 and 4–5, there are still enough lines connected to bus 4 to supply its load. By considering lines 2–4 and 4–5 as switchable, loops would be relaxed while meeting the load balance requirements.

Case 4: In this case, the standing phase angle difference limits of the switchable lines are considered. The standing phase angle difference limit for switchable lines is considered to be 4 degrees. Imposing this limit, when the absolute value of the difference of phase angles in two sides of the switched line is less than its standing phase angle difference limit, the line cannot be switched back to the system.

In Case 1, both switchable lines 2–4 and 4–5 are switched back to the system at hour 16. The standing phase angle difference for these two lines is 10.24 and 1.85 degrees, respectively. Since the standing phase angle difference of line 2–4 is more than its limit, this line cannot be switched back at hour 16. Imposing this constraint to the problem, the switchable line 2–4 is switched back to the system one hour earlier, i.e., hour 15. At this hour, the line can be switched back to the system, since the standing phase angle difference is less than its limit. With this change in the state of switchable lines, the generation of unit 1 is decreased by 2.5 MW and the generation of unit 2 is increased by 2.5 MW. This change in dispatch leads to an insignificant increase in the total operating cost.

B. IEEE 118-Bus System

A modified IEEE 118-bus system is used to study the SCUC with TS. The system has 118 buses, 54 units, and 186 branches. The data for this system are found in motor.ece.iit.edu/data/SCUC_118test.xls. Lines 30, 78, 90, 115, 151, 159, and 164 are considered switchable. Three cases are considered. The first case is the base case UC, and the second one is SCUC when considering contingencies. At the third case, the results of the proposed model are compared with those of an integrated model.

Case 1: In this case, the SCUC approach without TS is used to find the generating unit schedules with a total operating cost of \$1 081 320.36. Using TS, seven lines are considered as switchable. The UC schedule found in the first iteration of the problem cannot satisfy the TS feasibility and Benders cuts are

TABLE VIII
UC SCHEDULE OF THE IEEE 118-BUS SYSTEM IN CASE 1 USING TS

[illegible]

TABLE IX
LINE SCHEDULE OF THE IEEE 118-BUS SYSTEM IN CASE 1 USING TS

[illegible]

added to the UC problem. The feasible schedule is found after two iterations and shown in Table VIII. The TS schedule is shown in Table IX with a total operating cost of \$1 078 155.86, which signifies a 0.30% improvement in the total operating cost as compared with the UC solution. The total execution time is 94 s.

Case 2: In this case, three simultaneous contingencies are considered. The contingencies include outages of unit 13, line 75–77, and line 85–89. Comparing the new schedule with that in Case 1, the states of 20 units have changed at different hours with a total operating cost of \$1 081 898. To apply the proposed

Fig. 4. Total operating cost comparison of integrated and decomposed models.

Fig. 5. Execution time comparison of integrated and decomposed models.

TS approach, the same lines as in Case 1 are considered switchable. The first UC result is feasible for the outage of line 75–77. So, the contingency of line 75–77 is controllable. Since the UC solution cannot lead to a feasible solution for the outages of unit 13 and line 85–89, these contingencies are uncontrollable. The obtained switchable line schedule is completely different from that in Case 1. The differences are highlighted in Table IX in comparison with those in Case 1. The corresponding UC solution is shown in Table VIII, where the highlighted values show the difference with Case 1. The total operating cost is \$1 080 846, which shows a 0.09% improvement. This solution is obtained in 136 s.

Case 3: To show the effectiveness of the proposed model in handling a larger number of switchable lines, the TS cases with integrated and decomposed formulation are compared. The number of switchable lines is changed from 0 to 50 with step of 10. Zero means that no switchable line exists in the system, while 50 represents that more than one fourth of the transmission lines in the system are switchable. The default relative optimality gap of CPLEX, i.e., 0.01%, is used as the stopping criterion. The total operating cost and execution time for these two models for different numbers of switchable lines are obtained and shown in Figs. 4 and 5, respectively.

In Fig. 4, the decomposed model does not outperform the integrated model from optimality point of view. The integrated model always has a similar or better total operating cost. However, the difference between the total operating costs of two models is negligible. When there is no line switching in

the system, the two models result in the same solution. Since the proposed model is an extension of the decomposed SCUC model, it is expected that in case of no line switching, the decomposed model finds the same solution as the integrated model. The worst case occurs at 40 switchable lines, where the difference is 0.02%.

In Fig. 5, for the small number of switchable lines, both models find the solution in a reasonable time. For instance for ten switchable lines, the decomposed model finds the solution in 1 min and the integrated model finds the solution in 4 min. However, as we increase the number of switchable lines, the execution time of the integrated model increases significantly, while that of decomposed model remains reasonable. In the case of 50 switchable lines, the solution of the decomposed model is obtained in 9 min, while that of integrated model is achieved in more than 80 min. This considerable increase in execution time is due to the large number of binary variables that should be handled by the integrated problem. However in the decomposed model, these binary variables are divided between the UC master problem and the TS subproblem. This division would help the large problems to find solutions in a reasonable execution time.

IV. CONCLUSIONS

In this paper, TS was integrated with UC for solving the multi-interval optimal generation unit scheduling with security constraints. The Benders decomposition was employed to separate the problem into a UC master problem and a TS subproblem. The UC master problem minimizes the total operating cost and calculates the optimal hourly commitment and dispatch of generation units subject to power balance and reserve requirements. The TS subproblem adjusts the hourly unit schedules and optimizes the switching state of lines to mitigate transmission violations in the base case and controllable and uncontrollable contingencies. The features of the proposed approach are listed as follows.

- The TS model can be used for congestion management. The TS application will lead to adjustments in line flows and congestion levels.
- The number of switchable lines was limited here. This assumption is consistent with practical switching applications. If we increase the number of switchable lines, TS may find better SCUC solutions which could also converge at slower rates.
- The applications of Benders decomposition to SCUC and TS would make the proposed approach more applicable to large power systems.
- The proposed TS approach is an extension of the conventional SCUC. Hence, if we ignore the line switching in the proposed approach, the final SCUC solution will be the same as that of the conventional SCUC.
- The proposed approach allows for the utilization of corrective modes before resorting to more expensive preventive solutions.

The UC and the Optimal TS Scheduling blocks use the MIP format. MIP problems use a predefined gap to determine the optimality of solution. If this gap is set to zero, the problem will find the optimal solution with a longer computation time.

Otherwise, the problem will be terminated with a near-optimal solution in a reasonable time. Usually a near-optimal solution is considered in real-time applications in power systems. Additional points for improving the proposed TS approach are listed as follows.

- Numerical methods may be developed for identifying the optimal set of switchable lines. Such methods may include additional strategies for system operations. For example in the IEEE 118-bus system, line 164 would be a good prospect for switching since it is switched off periodically.
- Practical line switching strategies could be considered like how often and how long a line could be on/off.
- Switching states of lines are employed in the Optimal TS Scheduling by means of cuts. These binary variables will be adjusted more accurately if we use additional constraints to make stronger connections between the switchable lines states and the generation dispatch. The approach could help the TS subproblem find the optimal solution in fewer iterations [27].

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Security-Constrained Generation and Transmission Outage Scheduling With Uncertainties

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Abstract—This study presents a stochastic model for the independent system operator's (ISO's) optimal coordinated long-term maintenance scheduling of generation units and transmission lines with short-term security-constrained unit commitment (SCUC). Random disturbances of power systems including forced outages of generation units and transmission lines, load forecast errors, and fuel price fluctuations are modeled as scenario trees using the Monte Carlo simulation. Lagrangian relaxation (LR) is applied to separate the coordinated optimization problem into long-term equipment maintenance (LTEM) and stochastic long-term SCUC (LTSCUC) subproblems. For the stochastic LTSCUC subproblem, scenario bundle constraints are relaxed via LR and the optimization problem is decomposed into deterministic LTSCUC problems. LR is applied to each deterministic LTSCUC to relax long-term fuel and emission limits and decompose the problem into short-term SCUC subproblems. The decomposition is further applied to short-term SCUC subproblems for separating hourly unit commitment and transmission network constraints. The unit commitment is formulated as a mixed-integer programming (MIP) problem and solved by the branch-and-cut method using CPLEX. The outcome of this study includes the hourly scheduling of outages of generation units and transmission lines, which corresponds to the optimal generation unit commitment and dispatch, and transmission flows. The hourly schedules minimize the total cost of operation and maintenance and satisfy long-term and short-term constraints of generation units and transmission network with the inclusion of power system uncertainty. A modified IEEE 118-bus system is used to exhibit the effectiveness of the proposed scheduling approach.

Index Terms—Optimal coordination of generation and transmission outage scheduling, security-constrained unit commitment, stochastic modeling of power systems.

NOMENCLATURE

Variables:

$F_{c,itp}(\cdot)$	Production cost function of unit i at time t at weekly interval p .
I_{itp}^s	Commitment state of unit i at time t at weekly interval p in scenario s .
J_{ltp}^s	State of line l at time t at weekly interval p in scenario s .
$LOLE^s$	Loss-of-load-expectation (LOLE) of scenario s .

$\overline{LOLE}$

LS_{btp}^s

P_{itp}^s

P_{btp}^s

$q_{l\tau}, r_{l\tau}$

$SU(D)_{itp}^s$

VP

VL_{EM}

VL^s

VLP

VLL

VLR

X_{itp}

Y_{ltp}

σ_{LOLE}

$\eta, \pi, \theta, \alpha, \beta$

$i, k, l, m, n, p, s, t, \tau$

Constants:

D_{itp}

e_i, l_i

E_{ltp}

MD

$MN_{\max, l}$

Expected quantity of loss-of-load-expectation for all S scenarios.

Load shedding at bus b at time t at weekly interval p in scenario s .

Power generation dispatch of unit i at time t at weekly interval p in scenario s .

System demand at bus b at time t at weekly interval p in scenario s .

Indicators for beginning and end maintenance of line l at time τ .

Startup/shutdown cost of unit i at time t at weekly interval p in scenario s .

Objective value of a feasible solution of the original problem.

Value of optimal LR function of the maintenance subproblem.

Value of optimal LR function of the SCUC subproblem in scenario s .

Value of a feasible solution of the stochastic SCUC subproblem.

Value of optimal LR function of the stochastic SCUC subproblem with relaxed bundle constraints.

Sum of optimal LR function values of maintenance and stochastic SCUC subproblems with relaxed bundle constraints.

Maintenance status of unit i at time t at interval p , 0 if unit is offline for maintenance, otherwise 1.

Maintenance status of line l at time t at interval p , 0 if line is offline for maintenance, otherwise 1.

Estimated standard deviation of LOLE.

Lagrangian multipliers.

Indexes.

Maintenance cost of unit i at time t at interval p .

Starting and ending time for maintenance window of equipment i .

Maintenance cost of line l at time t at interval p .

Maintenance duration.

Partial maintenance number upper limit of line l .

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$MT_{\min,l}^{off}$	Minimum time interval between two consecutive partial maintenances of line l .
$MT_{\min,l}^{on}$	Minimum duration for partial maintenance of line l .
NB	Number of buses.
NG	Number of units.
NL	Number of transmission lines.
NP	Number of weeks under study.
NT	Number of hours at each weekly interval (168 h).
P^s	Weight of scenario s .
$P_{\min,i}$	Minimum capacity of unit i .
$P_{\max,i}$	Maximum capacity of unit i .
$P_{D,tp}^s$	System demand at time t at weekly interval p in scenario s .
pv_{btp}^s	Value of lost load (VOLL) of bus b at time t at weekly interval p in scenario s .
S	Total number of scenarios.
σ_{fix}	Predefined standard deviation of LOLE.
$\varepsilon_1, \varepsilon_2$	Predefined convergence threshold.

I. INTRODUCTION

RESTRUCTURED power systems signify generation and transmission participants that are unbundled as self-interested entities which are also responsible for their maintenance outage scheduling in a competitive environment. In such environments, generation companies (GENCOs) submit their maintenance plans and constraints to the independent system operator (ISO) including maintenance time windows, available maintenance resources, and generation price offers. Transmission companies (TRANSCOs) also submit their respective maintenance plans and constraints to the ISO. The ISO is responsible for the optimal coordination of maintenance for generation units and transmission lines which would ensure the security of power systems and maximize the social welfare [1]–[3].

The study in [4]–[7] focused on generation and transmission maintenance and their coordination. However, the subject of transmission security in restructured power systems was not considered. Furthermore, random outages of power systems were not included when maximizing planned outages in long-term operation planning studies.

Our proposed coordinated long-term generation and transmission maintenance scheduling intends to coordinate generation and transmission outage scheduling with short-term security-constrained generation scheduling. Random outages of generators and transmission lines, load forecast errors, and fuel price fluctuations are considered which could influence the optimal maintenance outage scheduling. Such a detailed security-constrained maintenance scheduling approach provides a wider range of options for managing short-term

economics. Mathematically, the proposed problem is a stochastic, large-scale mixed-integer optimization problem and we introduce an effective decomposition and coordination strategy for its solution. The Lagrangian relaxation (LR) technique is applied to decompose such a stochastic and large mixed-integer programming (MIP) problem into tractable small-scale subproblems.

The proposed stochastic model could be applied to a vertically integrated utility. Here we consider fuel and emission constraints when scheduling the long-term operation of a utility. The same model can be utilized by centralized energy markets with ISOs. Here a combination of fuel and emission constraints used by traditional utilities, which is a quadratic function of power generation, represents the energy constraint for a GENCO. That is, GENCOs submit energy limits which indicate that the sum of daily generation for individual units, or the entire GENCO, would not exceed a prescribed level. The energy constraint is utilized by security-constrained unit commitment (SCUC) which is a market clearing tool in the day-ahead energy market.

The attributes of the proposed stochastic model, for the coordination of long-term generation and transmission maintenance schedules with the short-term SCUC, are presented in the following:

- 1) Coordination of generation maintenance with transmission maintenance. We introduce a binary variable for representing the transmission line status and adopt an optimization technique that applies to both generation and transmission maintenance scheduling.
- 2) LR is used to decompose the original stochastic problem into long-term equipment maintenance (LTEM) and long-term SCUC (LTSCUC) with fuel and emission subproblems, with unit commitment and transmission line status as coordinating (coupling) variables. The LTEM and LTSCUC subproblems are solved individually and violations are identified. Lagrangian multipliers are updated iteratively for subproblems until the stopping criterion is met.
- 3) Random outages of generators and transmission lines, load forecast errors, and fuel price fluctuations are simulated by the Monte Carlo method when solving the LTSCUC subproblem. The uncertainty could influence the maintenance schedule when updating Lagrangian multipliers. The scenario-based technique is used to solve the stochastic LTSCUC subproblem. Scenario reduction is adopted when solving the stochastic LTSCUC as a tradeoff between computation time and solution accuracy. The LR method is adapted to relax bundle constraints and a modified surrogate subgradient method is used for a faster convergence.
- 4) The chronological load profile is considered in the LTEM scheduling and its coordination with the short-term SCUC.

The rest of the paper is organized as follows. Section II describes the proposed model and its solution methodology. Section III presents the detailed formulation of maintenance and generation scheduling subproblems. The coordination and solutions methodologies are presented in Section IV. Section V presents and discusses a modified IEEE 118-bus system with 54 units and 91 loads. The conclusion is drawn in Section VI.

II. STOCHASTIC MODEL DESCRIPTION

In this paper, we analyze the optimal maintenance scheduling of a vertically integrated utility. The same methodology would also apply to restructured power systems. The utility's objective is to minimize the hourly cost of security-constrained short-term operation and long-term maintenance.

In applying (1) to a vertically integrated utility, the first two terms represent the cost of maintenance for generation and transmission equipment respectively. The remaining terms represent the production cost. We could consider a variable hourly maintenance cost coefficients (D_{itp} and E_{itp}) for each equipment. If the proposed model is used in restructured power systems, GENCOs and TRANSCOs would be independently responsible for generation and transmission maintenance, no equipment maintenance cost will appear in (1), and D_{itp} and E_{itp} would be zero. The ISO would use the objective (1) to schedule equipment maintenance outages based on a GENCO's or a TRANSCO's preferred maintenance schedule. Accordingly, D_{itp} and E_{itp} will be zero during the most preferred periods for maintenance of the corresponding equipment in order to increase the chance of maintenance during such periods:

$$\begin{aligned} \text{Min} \left\{ \sum_{p=1}^{NP} \sum_{t=1}^{NT} \sum_{i=1}^{NG} D_{itp} \cdot (1 - X_{itp}) \right. \\ + \sum_{p=1}^{NP} \sum_{t=1}^{NT} \sum_{l=1}^{NL} E_{itp} \cdot (1 - Y_{itp}) + \sum_{s=1}^S P^s \\ \cdot \sum_{p=1}^{NP} \sum_{t=1}^{NT} \left\{ \sum_{i=1}^{NG} [F_{c,itp} (P_{itp}^s \cdot I_{itp}^s) + SU_{itp}^s + SD_{itp}^s] \right. \\ \left. + \sum_{b=1}^{NB} p_{btp}^s \cdot LS_{btp}^s \right\} \left. \right\}. \quad (1) \end{aligned}$$

Such objectives may not be easily realized by a one-step optimization technique due to the enormity of the maintenance scheduling problem. Thus, we schedule the long-term equipment maintenance and the short-term unit commitment problems separately, which are based on the decomposition technique depicted in Figs. 1–3. The distinct features of the proposed model include the way we introduce stochastic variables in the coordinated generation and transmission maintenance problem, handle scenario bundle constraints, and link maintenance and operation schedules. Fig. 1 shows the decomposition strategy of LTEM represented by (2)–(9) and LTSCUC constraints. Coupling constraints (11), (12) of LTEM and LTSCUC are relaxed using the LR method. LTEM and LTSCUC subproblems are solved individually before the coupling constraints are checked.

If the coupling constraints (11), (12) are not satisfied, Lagrangian multipliers η and π corresponding to the two constraints are updated and the pseudo price signals are fed back to the subproblems. We introduce I as the unit commitment status variable and J as the transmission line status variable, so that the transmission line maintenance can be treated the same way as that of generation units. The network security is checked in the deterministic LTSCUC subproblem and the same strategy is used for updating the Lagrangian multiplier η and π .

Fig. 1. Decomposition and coordination of LTEM and LTSCUC.

Fig. 2. Decomposition of scenario bundle constraints.

Fig. 3. Decomposition and coordination of deterministic LTSCUC.

Fig. 2 shows the decomposition strategy of the stochastic LTSCUC for managing the scenario bundle constraints (10). Scenario bundle constraints are relaxed by the LR method and the deterministic LTSCUC problem (shown in Fig. 3) is solved in each scenario. If the LTSCUC results in Fig. 2 do not satisfy the scenario bundle constraints, Lagrangian multipliers θ are updated and the corresponding pseudo price signals are fed back to scenarios for the next iterative solution. Since the problem is not convex, there is no guarantee that the bundle constraints would be entirely satisfied. Thus, the scenarios consider approximate solutions for fast convergence while maintaining a rel-

atively high level of accuracy. The iterative process will stop when the total violation of weighted bundle constraints is below a certain tolerance. A heuristic process is then used to obtain a feasible solution for satisfying the scenario bundle constraints. We use the modified surrogate subgradient method to improve the convergence. The solution details shown in the next section illustrate a tradeoff between the computation speed and the accuracy of solution.

Fig. 3 illustrates the decomposition of the deterministic LTSCUC into tractable subproblems. Fuel and emission constraints are relaxed with resource penalty prices represented by Lagrangian multipliers α and β . Based on the decomposition process, the individual short-term unit commitment problems will be solved without the fuel and emission constraints.

If the results do not satisfy the fuel and emission constraints, the Lagrangian multipliers α and β are updated and the corresponding penalty resource prices are fed back to solve the short-term subproblems again [8], [9].

III. FORMULATION OF SUBPROBLEMS

The LTEM and LTSCUC formulations, constraints, and coordination are summarized as follows.

1) *Generation Maintenance Constraints:* Generation maintenance windows: In the following, (2) shows starting and ending times when the maintenance is allowed. Also, (3) represents the total maintenance duration, and (4) shows that each unit could only be maintained once within the maintenance window:

$$X_{i\tau} = 0 \text{ or } 1 \text{ when } e_i \leq \tau \leq l_i; \\ \text{otherwise } X_{i\tau} = 1 \forall i, \tau < e_i \text{ or } \tau > l_i \quad (2)$$

$$\sum_{\tau=e_i}^{l_i} (1 - X_{i\tau}) = MD_i \quad \forall i \quad (3)$$

$$\sum_{\tau=k}^{k+MD_i-1} (1 - X_{i\tau}) \geq MD_i \cdot [X_{i(\tau-1)} - X_{i\tau}] \\ \forall i, k = e_i, \dots, l_i - MD_i + 1 \\ \sum_{\tau=k}^{l_i} \{1 - X_{i\tau} - [X_{i(k-1)} - X_{ik}]\} \geq 0 \\ \forall i, k = l_i - MD_i + 2, \dots, l_i. \quad (4)$$

Generation maintenance resources and crew availability: The crew availability would limit the number of units that can be maintained simultaneously. For example, if units 1, 2 and 3 are to be maintained simultaneously, the constraint is represented as $X_{1\tau} = X_{2\tau} = X_{3\tau}$. Otherwise, for a single equipment, $(1 - X_{1\tau}) + (1 - X_{3\tau}) + (1 - X_{3\tau}) \leq 1$. If unit 1 is maintained before unit 2, $\sum_{\tau=1}^t (1 - X_{1\tau}) - (1 - X_{2t}) \geq 0$. While $X_{1t} = X_{2t}$ indicates that unit 1 and 2 are to be on maintenance outage simultaneously. We can also represent limited resources for maintenance and crew availability at each location as $\sum_{i \in A} f_{Ri} \cdot (1 - X_{i\tau}) \leq H_{R\tau}$ where f_{Ri} is the resource needed for the maintenance of unit i and $H_{R\tau}$ is the total resource quantity available at time τ for area A.

2) *Transmission Maintenance Constraints:* Partial maintenance is allowed for transmission lines. Hence

$$Y_{l\tau} = 0 \text{ or } 1 \text{ when } e_l \leq \tau \leq l_l; \\ \text{otherwise } Y_{l\tau} = 1 \forall l, \tau < e_l \text{ or } \tau > l_l \quad (5)$$

$$\sum_{\tau=e_l}^{l_l} (1 - Y_{l\tau}) = MD_l \quad \forall l \quad (6)$$

$$q_{l\tau} - r_{l\tau} = Y_{l(\tau-1)} - Y_{l\tau}, \quad q_{l\tau} + r_{l\tau} \leq 1, \\ 1 \leq \sum_{\tau=1}^{NT \cdot NP} r_{l\tau} \leq MN_{\max, l} \quad \forall l, \forall \tau \quad (7)$$

$$\sum_{\tau=k}^{k+MT_{\min, l}^{on}-1} (1 - Y_{l\tau}) \geq (Y_{l(\tau-1)} - Y_{l\tau}) \cdot MT_{\min, l}^{on} \\ \forall l, k = e_l, \dots, l_l - MT_{\min, l}^{on} + 1 \\ \sum_{\tau=k}^{l_l} \{1 - Y_{l\tau} - [Y_{l(k-1)} - Y_{lk}]\} \geq 0 \\ \forall l, k = l_l - MT_{\min, l}^{on} + 2, \dots, l_l \quad (8)$$

$$\sum_{\tau=k}^{k+MT_{\min, l}^{off}-1} Y_{l\tau} \geq (Y_{l\tau} - Y_{l(\tau-1)}) \cdot MT_{\min, l}^{off} \\ \forall l, k = e_l, \dots, l_l - MT_{\min, l}^{off} + 1 \\ \sum_{\tau=k}^{l_l} \{Y_{l\tau} - [Y_{lk} - Y_{l(k-1)}]\} \geq 0 \\ \forall l, k = l_l - MT_{\min, l}^{off} + 2, \dots, l_l. \quad (9)$$

3) *Stochastic LTSCUC Constraints:* Short-term SCUC constraints presented in [18] are considered here in addition to

- *Reliability constraints:* An explicit reserve requirement constraint is not introduced. The optimal reserve requirement is implicitly determined because we add a penalty load shedding item to the objective function and include a LOLE constraint.
- *Scenario bundle constraints:* Scenario bundle constraints indicate that if two scenarios s and s' are indistinguishable from the beginning to time (P, τ) on the basis of information available at time (P, τ) , then the generator commitment decisions rendered for the two scenarios must be identical from the beginning to time τ . $B(s, P, \tau)$ represents a part of scenario s from the beginning to time (P, τ) . In the scenario bundle constraints (10), the generator commitment decision I rather than the line status J is included. The line status J is used as a state variable to relate the transmission maintenance decision and SCUC in (12). Based on (12), if a line is on maintenance, the line status J for all scenarios would be zero; otherwise, J would be one. The status of J is determined by the optimization of LTSCUC because the line would be utilized in minimizing the operation cost. That is, it would not be necessary to include the line status in the scenario bundle constraints (10):

$$I_{itp}^s = I_{itp}^{s'}, \text{ for } (p, t) \in \{(P, \tau) | B(s, P, \tau) = B(s', P, \tau)\}. \quad (10)$$

The detailed formulation of LTSCUC constraints can be found in our previous works [20], [22].

4) *Coupling Constraints for LTEM and LTSCUC in Fig. 1:* Coupling constraints of generator maintenance X and unit commitment status I (11):

$$I_{itp}^s \leq X_{itp} \quad \forall s, \forall i, \forall t, \forall p. \quad (11)$$

Coupling constraints of transmission line maintenance Y and transmission line status J (12):

$$J_{ltp}^s \leq Y_{ltp} \quad \forall s, \forall l, \forall t, \forall p. \quad (12)$$

The proposed stochastic model differs from the deterministic one in several respects. First, the objective of the proposed stochastic model is to minimize the expected production cost of all scenarios, whereas the deterministic model would only minimize the production cost of a certain deterministic case. Second, the impact of the variance of uncertain variable on the maintenance schedule is considered. We also incorporate the coupling constraints of generator maintenance and unit commitment status (11) and the coupling constraints of transmission line maintenance and transmission lines status (12). Furthermore, there are scenario bundle constraints in the stochastic LTSCUC subproblem. Hence, the solution of stochastic model which includes a set of weighted scenarios is not simply the same as solving a deterministic model separately for each scenario.

IV. SOLUTION OF SUBPROBLEMS

A. Coupling Constraints for LTEM and LTSCUC Subproblems

LR is employed to solve the coupling constraints (11), (12). Once constraints are relaxed and introduced into the LTEM and LTSCUC subproblems via the Lagrangian multipliers η and π , the modified LTEM and LTSCUC subproblems at iteration n are presented in (13) and (14), respectively:

$$\begin{aligned} & V_{LTEM}(\eta^n, \pi^n) \\ &= \text{Min} \sum_{p=1}^{NP} \sum_{t=1}^{NT} \sum_{i=1}^{NG} \left[D_{itp} \cdot (1 - X_{itp}) - \left(\sum_s \eta_{itp}^{s,n} \right) \cdot X_{itp} \right] \\ &+ \sum_{p=1}^{NP} \sum_{t=1}^{NT} \sum_{l=1}^{NL} \left[E_{ltp} \cdot (1 - Y_{ltp}) - \left(\sum_s \pi_{ltp}^{s,n} \right) \cdot Y_{ltp} \right] \end{aligned} \quad (13)$$

S.t. constraints (2)–(9)

$$\begin{aligned} & \text{Min} \sum_{s=1}^S \sum_{p=1}^{NP} \sum_{t=1}^{NT} \left\{ P^s \cdot \left\{ \sum_{i=1}^{NG} [F_{c,itp} (P_{itp}^s \cdot I_{itp}^s) \right. \right. \\ & \quad \left. \left. + SU_{itp}^s + SD_{itp}^s] \right. \right. \\ & \quad \left. \left. + \sum_{b=1}^{NB} p_{b,tp}^s \cdot LS_{b,tp}^s \right\} \right. \\ & \quad \left. + \sum_{i=1}^{NG} \eta_{itp}^{s,n} \cdot I_{itp}^s + \sum_{l=1}^{NL} \pi_{ltp}^{s,n} \cdot J_{ltp}^s \right\} \end{aligned} \quad (14)$$

S.t. stochastic LTSCUC constraints described in Section III.

After obtaining a solution for generator maintenance $\mathbf{X}$, transmission line maintenance $\mathbf{Y}$, as well as unit commitment $\mathbf{I}$ and transmission line status $\mathbf{J}$, we check the constraints and update the corresponding multipliers η and π by applying the subgradient method [19]. The Lagrangian iteration continues until a converged solution which would meet the stopping criterion is obtained:

$$\begin{aligned} & \text{If } \hat{I}_{itp}^{s,n} \geq \hat{X}_{itp}^n, \\ & \quad \eta_{itp}^{s,n+1} = \eta_{itp}^{s,n} + S_G^{up,n} \cdot \left(\hat{I}_{itp}^{s,n} - \hat{X}_{itp}^n \right) / \left\| \hat{I}_{itp}^{s,n} - \hat{X}_{itp}^n \right\| \\ & \text{Otherwise} \\ & \quad \eta_{itp}^{s,n+1} = \eta_{itp}^{s,n} + S_G^{down,n} \cdot \left(\hat{I}_{itp}^{s,n} - \hat{X}_{itp}^n \right) / \left\| \hat{I}_{itp}^{s,n} - \hat{X}_{itp}^n \right\| \\ & \text{If } \hat{J}_{ltp}^{s,n} \geq \hat{Y}_{ltp}^n, \\ & \quad \pi_{ltp}^{s,n+1} = \pi_{ltp}^{s,n} + S_L^{up,n} \cdot \left(\hat{J}_{ltp}^{s,n} - \hat{Y}_{ltp}^n \right) / \left\| \hat{J}_{ltp}^{s,n} - \hat{Y}_{ltp}^n \right\| \\ & \text{Otherwise} \\ & \quad \pi_{ltp}^{s,n+1} = \pi_{ltp}^{s,n} + S_L^{down,n} \cdot \left(\hat{J}_{ltp}^{s,n} - \hat{Y}_{ltp}^n \right) / \left\| \hat{J}_{ltp}^{s,n} - \hat{Y}_{ltp}^n \right\| \end{aligned}$$

where $\|\cdot\|$ stands for a Euclidean norm, $S_G^{up,n}$, $S_G^{down,n}$, $S_L^{up,n}$ and $S_L^{down,n}$ are step sizes at iteration n for updating multipliers of constraints (11), (12). Usually a constant step size or the one that decreases with iterations such as $(1+C)/(n+C)$ or $1/(C1+C2 \cdot \sqrt{n})$ would be used, where C , $C1$, and $C2$ are pre-defined positive constants. In [23] the bundle method was also proposed to update Lagrangian multipliers in order to improve the updating process.

Concerning the coupling constraints (11), (12) for the LTEM and LTSCUC subproblems, the original problem is non-convex with integer variables. So additional heuristics strategies are applied to derive a feasible solution when a predefined number of Lagrangian iterations or the maximum execution time is reached. In this case, the LTSCUC solution would offer a feasible solution when generation and transmission maintenance schedules are assumed fixed according to their values in the current Lagrangian solution.

B. Stochastic Simulation

We model forced outages of generation units and transmission lines as independent Markov processes, load forecast errors as uniform random variables, and fuel price fluctuations as Ornstein-Uhlenbeck processes. For an ISO model, we could replace the fuel price with bidding prices offered by market participants since the ISO does not deal with fuel prices. The solution process will still be the same as that discussed in this section. We introduce a set of scenarios in the Monte Carlo method for modeling the stochastic conditions. For stochastic programming, we assign a weight P^s to each scenario that reflects the possibility of its occurrence.

A two-state continuous-time Markov chain model is used to represent available and unavailable states of generators and transmission lines. The parameters used for the Monte Carlo simulation are failure and repair rates of each power system component. Using failure and repair rates, forced outages are simulated for a specified time period with the assumption that the power system is at the base case at the beginning of the

period. Power system components are assumed independent in our scenario-based simulation and the simultaneous effects of outages are presented in scenario trees. For the simulation of load forecast errors, we divide the entire scheduling horizon into several time intervals. For each time interval we create additional scenarios based on historical data. The probabilities are assigned to hourly load quantities according to the likelihood of their occurrence. The proposed scenarios in each time interval reflect the representative days/hours chosen for each week/season.

The proposed approach makes it easy for a maintenance scheduler to include the relevant data of a certain week/season after assigning a suitable weight to each load scenario. It is desirable that one could shift the maintenance schedule to periods with higher fuel prices for mitigating higher operation cost associated with maintenance outages. We employ the Ornstein-Uhlenbeck process to simulate random fluctuations in fuel price [20], [21]. According to Fig. 4, we generate a set of scenarios, each representing possible fluctuations in fuel price, load forecast errors, as well as the availability of generation units and transmission lines.

In the proposed model, we use a low-discrepancy Monte Carlo method, Latin hypercube, to generate a set of scenarios. Weights for all scenarios in the initial scenario catalog generated by the Monte Carlo method are the same. Scenario reduction is adapted for a tradeoff between solution accuracy and computation speed, because computation requirements for solving scenario-based optimization models would depend on the number of scenarios [13], [14]. Here we use the following criterion for the stochastic LTSCUC subproblem while taking into account the solution accuracy:

$$\sigma_{LOLE} = \sqrt{\frac{\sum_{s=1}^S P^s \cdot (LOLE^s - \overline{LOLE})^2}{S \cdot (S-1)}} \quad (15)$$

$$\sigma_{LOLE} < \sigma_{fix} \quad \overline{LOLE} = \sum_{s=1}^S P^s \cdot LOLE^s.$$

The results are assumed to be reasonably accurate when the estimated standard deviation of LOLE, σ_{LOLE} , is less than the predefined boundary σ_{fix} .

C. Scenario Bundle Constraints

The sample scenarios for representing the uncertainty are solved and a good combination of solution outcomes is selected to represent the stochastic solution. The solution outcome would satisfy the constraint that if two scenarios are indistinguishable from the beginning to time τ on the basis of information available at time τ , then the decision rendered for two scenarios must be identical from the beginning to time τ .

The LR method is adopted to relax the scenario bundle constraints. Thus the stochastic problem is divided into several tractable subproblems for each scenario. Once the scenario

Fig. 4. Representation of uncertainty in a scenario tree.

bundle constraints are relaxed, the LTSCUC subproblem for each scenario is represented as

$$VL^s(\theta^k) = \min \sum_{p=1}^{NP} \sum_{t=1}^{NT} \left\{ P^s \cdot \left\{ \sum_{i=1}^{NG} [F_{c,itp} (P_{itp}^s \cdot I_{itp}^s) + SU_{itp}^s + SD_{itp}^s] + \sum_{b=1}^{NB} p v_{b,tp}^s \cdot LS_{b,tp}^s \right\} + \sum_{i=1}^{NG} \eta_{itp}^{s,n} \cdot I_{itp}^s + \sum_{l=1}^{NL} \pi_{itp}^{s,n} \cdot J_{itp}^s \right\} + \sum_{p=1}^{NP} \sum_{t=1}^{NT} \sum_{s \in B(s,P,\tau) = \Omega_{P\tau}} \theta_{itp}^{s,k} \cdot I_{itp}^s \quad (16)$$

S.t. stochastic LTSCUC constraints described in Section III except scenario bundle constraints.

The target c_{itp} , which is the weighted average of decision, is the same for all scenarios. Let $\theta_{itp}^{s,k}$ be the k th iteration of Lagrangian multiplier corresponding to $I_{itp}^s = c_{itp}$, $i = 1 \dots NG$, $(p, t) \in \{P, \tau\}$. We obtain a new decision by calculating the expected value of I_{itp}^s as c_{itp}^k , updating $\theta_{itp}^{s,k+1}$, and continuing the iteration. The iteration is terminated when the total weighted violation of bundle constraints, $\sum_{p=1}^{NP} \sum_{t=1}^{NT} \sum_{s \in B(s,P,\tau) = \Omega_{P\tau}} P^s \cdot |I_{itp}^s - c_{itp}|$, is below a certain threshold. Here, $|\cdot|$ denotes the absolute value. In order to accelerate the convergence, the surrogate gradient algorithm is adopted. The process starts by finding a scenario s which has the largest weighted violation $\sum_{p=1}^{NP} \sum_{t=1}^{NT} P^s \cdot |I_{itp}^s - c_{itp}|$, updating multipliers, and calculating the scenario s only. The detailed steps are given in Appendix A. The optimality conditions for the proposed dual solution via the surrogate sub-gradient method was provided in [15], [16]. Here, multipliers move iteratively closer to their global optimal.

In each scenario, the LR algorithm is adopted for the solution of deterministic long-term SCUC problem which deals

with fuel and emission constraints. The LR will divide the original problem into several tractable subproblems, i.e., short-term SCUC subproblems based on MIP. The Lagrangian multipliers are penalty price signals which optimize the allocation of fuel consumption and emission allowance based on a hybrid subgradient and Dantzig-Wolfe method [8], [17], [18].

The iteration will be terminated when the total weighted violation of bundle constraints is below a certain threshold. Accordingly, a heuristic process will be used to introduce a feasible solution with respect to the scenario bundle constraints. Here, we find the largest weighted violation $P^s \cdot |I_{itp}^s - c_{itp}|$ and adjust the multiplier θ_{itp}^s corresponding to hour t at period p of scenario s . The subproblem for the period p of scenario s is solved again and new c_{itp} are computed. The process will be repeated for finding the next maximum violation and terminated within a finite number of iterations.

There are two main LR loops. $VL_{EM}(\eta^n, \pi^n)$ in (13) and $VL^s(\theta^k)$ in (16) are the optimal LR function values for the LTEM and LTSCUC subproblems in scenario s at the current iteration. The optimal LR function of the stochastic LTSCUC subproblem with the relaxed bundle constraints VLL at the current iteration is calculated by (17). The sum of optimal LR function values for the maintenance and the stochastic LTSCUC subproblems with relaxed bundle constraints VLR at the current iteration is calculated by (18). The Lagrangian iterations will continue until the relative difference (duality gap) between VP (upper bound) and VLR (lower bound) of the optimal solution is within a pre-defined tolerance as stated in (19):

$$VLL = \sum_s VL^s(\theta^k) \quad (17)$$

$$VLR = VL_{EM}(\eta^n, \pi^n) + \sum_s VL^s(\theta^k) \quad (18)$$

$$|(VP - VLR)/VLR| \leq \varepsilon_1. \quad (19)$$

Appendix B provides a proof for the validation of stopping criterion. The maximum number of iterations would have to be set since the duality gap could be intrinsic to the non-convex problem and would not be further reduced.

V. CASE STUDIES

A modified IEEE 118-bus system is considered in this section to demonstrate the proposed approach. The intention is to schedule the hourly maintenance, unit commitment, and generation economical dispatch over a 672-h (i.e., four weeks) horizon. The 118-bus system is composed of 54 thermal units, 186 branches, and 91 loads. The test data for the 118-bus system are given in <http://motor.ece.iit.edu/data/coop>. The annual peak load of the system is 6000 MW and the load trend over the study horizon is shown in Fig. 5.

For this system, three generators are considered for maintenance, each can be on maintenance at any hour. Only one transmission line L51 is considered for maintenance and a partial maintenance is acceptable. The maximum allowable number of partial maintenances for this line is two. The partial maintenance needs to last at least eight hours with a minimum of eight hours between two consecutive partial maintenances. The concern of

Fig. 5. Load profile in a 672-h horizon for the 118-bus system.

TABLE I
GENERATOR MAINTENANCE LIMITS FOR CASES 1–3

Unit	At Bus	Windows	Duration (hours)	Cost (\$/hour)
U10	25	1 – 624	24	1200
U20	49	1 – 624	24	1000
U34	76	1 – 624	24	400

TABLE II
TRANSMISSION LINE MAINTENANCE LIMITS FOR CASES 1–3

Line	From Bus	To Bus	Windows	Duration (hours)	Cost (\$/hour)
L51	38	37	1 – 336	18	5000
Maximum number of partial maintenances		Minimum duration of partial maintenance (hours)		Minimum interval between partial maintenances (hours)	
2		8		8	

this paper is to study the impact of uncertainties, on the coordinated maintenance scheduling of generation units and transmission lines with SCUC. Thus in the case study, emission limits and fuel consumption constraints are relaxed by introducing very large emission and fuel upper limits. The application of LR for relaxing emission and fuel consumption constraints, procedures for obtaining feasible solutions, and the performance of the system was discussed in [9] and [20].

We study four maintenance cases for a 672-h (four-week) period:

- Case 1) Uncoordinated maintenance and unit commitment schedules.
- Case 2) Coordinated generation unit and transmission line maintenance schedule without the consideration of uncertainty. We refer to this case as the expected value problem since expected values are used for load forecast and fuel price.
- Case 3) Impact of uncertainty on the coordinated schedule.
- Case 4) Same as Case 3 with a three-day maintenance duration.

For the first three cases, the equipment maintenance data listed in Tables I and II are used. In Case 4, the same data as those of Cases 1–3 are used except the maintenance duration is increased to 72 h. These cases are discussed as follows.

Case 1: LTEM and LTSCUC subproblems are not coordinated, so the optimal maintenance schedules are obtained individually for generators and transmission line maintenance subproblems as described in part one and two of Section III. The optimal maintenance schedule is shown in Fig. 6.

Fig. 6. Equipment maintenance in Case 1.

TABLE III
CLASSIFICATION OF UNITS

Class	Units
Base	4 5 10 11 20 21 24 25 27 28 29 36 39 40 43 44 45
Intermediate	1 2 3 6 12 13 31 32 38 42 50 54
Peaking	7 8 9 14 15 16 17 18 19 22 23 26 34 35 37 47 48 51 52 53
Off	30 33 41 46 49

The maintenance of units U10, U20, and U34 are scheduled at hours of 289–312, 145–168, and 337–360, respectively. The maintenance of line L51 is scheduled at hours 144–152 and 312–320. Based on the above maintenance schedule, we optimize the hourly unit commitment schedule for 672 h without the consideration of system uncertainty. The total cost is \$42 133 556, which includes the generator maintenance cost of \$62 400, line maintenance cost of \$90 000, and operation cost of \$41 981 156. In the uncoordinated case, the unit commitment schedule is not considered in the maintenance problem. If the proposed maintenance schedule is used as input to the unit commitment problem, the commitment may be more expensive or could result in load shedding. For example in Fig. 6, L51 and U20 are both maintained during hours 145–152. An inefficient utilization of generators and lines at this period could increase the total cost and/or result in load shedding.

Case 2: This case coordinates the equipment maintenance outage and the unit commitment schedule without considering any uncertainty. Table III shows, based on the percentage of time, the units that are committed as base (committed more than 85% of the time in four weeks), intermediate (between 85% and 10% of time), peaking (less than 10% of time), and off units. The optimal maintenance schedule is shown in Fig. 7, in which much of the maintenance is scheduled near the minimum loading hours for maintaining the power systems reliability and economics. The maintenance of base units U10 and U20 is scheduled at the minimum loading hours of 481–504 and 457–480, respectively. Furthermore, the maintenance of line L51 is at hours 140–157, which shifts the maintenance of peaking unit U34 to the next available minimum loading hours of 289–312. The optimal cost is \$40 176 827 which includes the generator maintenance cost of \$62 400, line maintenance cost of \$90 000, and operation cost of \$40 024 427. Compared with the optimal cost of Case 1, a saving of \$1 956 729 is achieved due to the simultaneous consideration of LTEM and LTSCUC subproblems.

Case 3: In this case, the power system uncertainty is considered for the coordination of LTEM and LTSCUC problems.

Fig. 7. Equipment maintenance in Case 2.

TABLE IV
PROBABILITIES OF EACH SCENARIO AFTER SCENARIO REDUCTION

Scenario	1	2	3	4	5	6
Probability	0.01	0.01	0.28	0.01	0.01	0.39
Scenario	7	8	9	10	11	12
Probability	0.01	0.01	0.01	0.01	0.01	0.24

TABLE V
OPERATION COST FOR EACH SCENARIO (\$)

Scenario	Operation Cost	Scenario	Operation Cost
1	40,767,940	7	39,288,403
2	40,202,328	8	41,929,654
3	40,984,806	9	41,345,839
4	39,963,756	10	41,724,055
5	40,717,038	11	41,637,338
6	40,581,050	12	41,283,492
EXP		40,886,157±64,223	
Relative Error (%)		0.157	

At each hour, there are 461 decision variables and 2094 continuous variables. Thus the entire coordinated problem over a 672-h horizon contains 309 792 binary variables and 1 407 168 continuous variables. One hundred scenarios are created using the low-discrepancy Monte Carlo simulation method with each scenario representing forced outages of generation units and transmission lines, load forecast errors, and fuel price fluctuations. The scenario reduction method reduces the total number of scenarios from 100 to 12 as a tradeoff between the calculation speed and the solution accuracy. Table IV shows the scenario weights after reduction. Table V provides the operation cost of each scenario, the expected operation cost, and its variance. In Table V and thereafter, “EXP” is the expected value of all scenarios based on the 95% confidence interval, and the “Relative Error” is calculated as the ratio of 95% confidence interval to the expected value. The results presented in Tables V show that after 90% reduction, relative errors in operation costs are less than 1%.

Table VI compares maintenance cost, operation cost, and total cost for the above three cases. The coordination of LTEM and LTSCUC subproblems has reduced the total cost by \$1 956 729 in Case 2 as compared with Case 1. This reduction is due to the coordination of LTEM and LTSCUC subproblems which avoids any unnecessary load shedding or the commitment of peaking units. It also shows that the uncertainty has increased the total operation cost by \$861 730 in Case 3 as compared with Case 2. The inclusion of uncertainty would provide a more comprehensive coordination of maintenance outages and hourly unit commitment to satisfy the system security constraints.

TABLE VI
COST COMPARISON IN THREE CASES

Case	Maintenance Cost (\$)	Operation Cost (\$)	Total Cost (\$)
Case 1	152,400	41,981,156	42,133,556
Case 2	152,400	40,024,427	40,176,827
Case 3	152,400	40,886,157	41,038,557

Fig. 8. Equipment maintenance in Case 3.

The optimal maintenance schedule is presented in Fig. 8. The load forecast in Fig. 8 is the same as that in Fig. 5. Among the simulated scenarios, the base unit U10 is on forced outage at hours 143–148 in scenario 6, and at hours 153–156 in scenario 10. Thus the optimal maintenance schedule of unit U10 is shifted to hours 145–168, and the maintenance of units U20 and U34 is shifted to hours 481–504 and 289–312, respectively.

Furthermore, the forced outage of transmission line L51 is simulated to be between hours 100–103 in scenario 3. Thus its maintenance outage is scheduled at periods of 97–105 and 126–134. The optimal cost is \$41 038 557 which includes the generator maintenance cost of \$62 400, the transmission line maintenance cost of \$90 000, and the operation cost of \$40 886 157.

To further evaluate the advantage of the stochastic model, a new set of scenarios is generated as shown in Table VII. We apply the stochastic problem solution (i.e., solution of Case 3) and the expected value problem solution (i.e., solution of Case 2) to each scenario. Tables VIII and IX show the operation costs for each scenario which are calculated by adopting the stochastic and the deterministic problem solutions of the maintenance and the unit commitment decision variables in each scenario. By comparison, the difference in the expected cost between stochastic and deterministic solutions is \$543 397 (i.e., \$41 491 977–\$40 948 580), which shows the potential operation cost saving for utilizing the stochastic model. By comparison, the upper limit of the expected operation cost for the proposed stochastic solution (i.e., \$40 948 580 + \$78 305 = \$41 026 885) is smaller than the lower limit of the expected operation cost of the deterministic decision (i.e., \$41 491 977 – \$105 887 = \$41 386 090), which exhibits a potential saving when applying the stochastic model. The scenario costs in Table VIII are not necessarily smaller than those in Table IX for the deterministic solution. The costs for scenarios 6, 9, and 11 in Table VIII are higher than those in Table IX.

Fig. 9 shows the relationship between maintenance and MCPs calculated by the LTSCUC subproblem in a four-week horizon. The maintenance is likely to be scheduled when MCPs are low.

TABLE VII
PROBABILITIES OF EACH SCENARIO AFTER SCENARIO REDUCTION

Scenario	1	2	3	4	5	6
Probability	0.18	0.03	0.25	0.03	0.12	0.09
Scenario	7	8	9	10	11	12
Probability	0.01	0.03	0.04	0.04	0.02	0.16

TABLE VIII
OPERATION COSTS USING STOCHASTIC VALUE SOLUTION (\$)

Scenario	Operation Cost	Scenario	Operation Cost
1	40,713,112	7	39,684,448
2	40,085,069	8	41,868,003
3	40,774,148	9	41,856,600
4	40,003,360	10	41,450,497
5	40,660,151	11	42,002,161
6	41,311,224	12	41,259,936
EXP		40,948,580 ± 78,305	
Relative Error (%)		0.191	

TABLE IX
OPERATION COSTS USING EXPECTED VALUE SOLUTION (\$)

Scenario	Operation Cost	Scenario	Operation Cost
1	41,514,139	7	40,080,098
2	40,477,383	8	42,674,071
3	41,162,509	9	40,873,073
4	40,396,517	10	42,247,362
5	41,463,449	11	41,487,957
6	40,985,739	12	42,516,608
EXP		41,491,977 ± 105,887	
Relative Error (%)		0.255

Fig. 9. Equipment maintenance in the stochastic case combined with MCP.

When units are on maintenance, expensive units have to be committed to meet system loads, which will increase certain hourly MCPs. The maintenance carried out at the low MCP periods could mitigate price risks in spot markets.

Figs. 10 and 11 show the iterative LR function values and the number of infeasible relaxed constraints (11) and (12), respectively. Fig. 11 shows that after 58 iterations of LTEM and LTSCUC, there are three violated coupling constraints corresponding to (11) and (12). We fix the maintenance schedule at iteration 58 and execute the LTSCUC to obtain a feasible and near-optimal solution of \$41 038 557. Fig. 10 shows that at iteration 58, the relative difference between VLR (\$40 865 834) and VP (\$41 038 557) is 0.423% which satisfies the precision requirement. For the stochastic LTSCUC, we show the convergence of the last stochastic LTSCUC subproblem.

Figs. 12 and 13 show the iterative LR function values of (17) and the weighted violation of bundle constraints, respectively. Fig. 13 shows that after 27 iterations, the total

Fig. 10. Iterative LR function values in Case 3.

Fig. 11. Number of infeasible constraints (11), (12) in Case 3.

Fig. 12. Iterative LR values of (16) for one stochastic LTSCUC in Case 3.

Fig. 13. Iterative weighted violation for one stochastic LTSCUC in Case 3.

weighted violation of bundle constraints is satisfied with a *VLL* of \$40 731 316. Then, we apply the heuristic process to find a feasible solution with respect to the scenario bundle constraints. This process would require another 15 iterations and the relative difference between *VLL* (\$40 731 316) and *VLP* (\$40 886 157) is 0.380% as shown in Fig. 12.

Case 4: In this case, a three-day maintenance duration is studied. Other assumptions are the same as those of Cases 1–3. Also, the power system uncertainty is modeled in this case. First, we consider the uncoordinated solution for LTEM and LTSCUC. The optimal maintenance schedule is shown in Fig. 14. The total cost is \$42 951 648 which includes the

Fig. 14. Maintenance with uncoordinated LTEM and LTSCUC.

Fig. 15. Maintenance with coordinated LTEM and LTSCUC in Case 4.

generator maintenance cost of \$187 200, the line maintenance cost of \$360 000, and the operation cost of \$42 404 448. Note that the uncoordinated LTEM and LTSCUC solutions will result in the scheduling of maintenance at periods with higher loads and more expensive operation costs. Next we consider the coordination of LTEM and LTSCUC solutions. The optimal maintenance schedule is shown in Fig. 15. Thus the optimal maintenance of unit U10 is scheduled at hours 145–216, which do not coincide with the low-load period at hours 121–144, and maintenance of units U20 and U34 is scheduled at hours 457–528 and 288–360, respectively. The total cost is \$41 798 521 which includes the generator maintenance cost of \$187 200, the line maintenance cost of \$360 000, and the operation cost of \$41 251 321.

As we compare the coordinated and the uncoordinated results, a saving of \$1 153 127 (i.e., 42 951 648 – 41 798 521) occurs due to the coordination of LTEM and LTSCUC. Furthermore, the inclusion of uncertainty provides a more accurate coordination of maintenance outage and hourly generation unit commitment, satisfies the system security constraints, and makes a more efficient usage of fuel contracts.

The cases are tested on a 2.39-GHz server and the execution time is estimated based on parallel calculations with 12 CPUs. The CPU time of LTSCUC for one scenario is about 4 min, and the number of iterations for scenario bundle constraints is within 27 for the given accuracy. The heuristic process for obtaining a feasible LTSCUC solution requires another 15 iterations and 15 * 0.2 minutes of computation. Thus the total CPU time for one iteration of LTEM and LTSCUC is about 1.9 h (4 * 27 + 15 * 0.2 min), with the parallel processing of LTEM and stochastic LTSCUC subproblems. Notice that only the objective functions are changed in the following iterations, and the solutions obtained at previous iterations are still feasible which can be used as initial solutions in the current iteration. Furthermore, previous Benders cuts can also be used at the current LTSCUC calculation. Such strategies would reduce

the computation time. However, these strategies would not be suitable for the last iteration, which is a heuristic process for obtaining the feasibility solution by fixing the LTEM solutions and executing the LTSCUC. In Case 3, the total number of iterations between LTEM and LTSCUC is 58, and the total CPU time is about 57 h. However, if parallel computation is further adopted in each short-term SCUC calculation process, the total CPU time would be reduced to about 4.6 hours. In general, the computation time may not be a major concern since the proposed model is applied to the long-term evaluation. For a complex stochastic mixed-integer linear problem presented in the paper, the proposed decomposition methodology would provide a reliable solution with an acceptable duality gap within a reasonable CPU time.

VI. CONCLUSIONS

Due to random events in power systems, a stochastic problem is proposed in this paper which coordinates LTEM and LTSCUC solutions with fuel and emission constraints. The approach considers the uncertainty in the availability of generation units and transmission lines, load forecast errors, as well as fuel price fluctuations, which are simulated as scenario trees by the Monte Carlo Method. LR is applied to decompose the original problem into maintenance and unit commitment subproblems, multipliers η and π corresponding to generator and line status coupling constraints are updated and fed back to the maintenance and unit commitment subproblems. The uncertainty is represented in the unit commitment scenarios, and LR is applied to solve the stochastic unit commitment problem with fuel allocation and emission allowance constraints. The solution results for the hourly maintenance and unit commitment subproblems represent the coordination of security, optimal unit commitment, resource allocation, and equipment maintenance in uncertain power systems. Compared with the expected value problem solution, the solution of the proposed stochastic model would provide potential savings in operation costs. The proposed approach can be applied to a vertically integrated utility as well as the ISO's operation in a restructured power system.

APPENDIX A

The process starts by finding a scenario s which has the largest weighted violation $\sum_{p=1}^{NP} \sum_{t=1}^{NT} P^s \cdot |I_{itp}^s - c_{itp}|$, updating multipliers, and calculating the scenario s only. The steps are as follows:

Step 0: Calculate I_{itp}^s for each scenario with $s = 1, \dots, S$. Compute $c_{itp} = \sum_{s \in B(s, P, \tau) = \Omega_{P\tau}} P^s \cdot I_{itp}^s / \sum_{s \in B(s, P, \tau) = \Omega_{P\tau}} P^s$.

Step 1: Update multipliers. The multipliers are updated as $\theta_{itp}^{s, k+1} = \theta_{itp}^{s, k} + r^k \cdot d_{itp}^{s, k}$, where r^k is the step size which satisfies $0 \leq r^k \leq (L^* - L^k) / \|d^k\|^2$ and $d_{itp}^{s, k}$ is the modified surrogate subgradient, which is given by

$$\begin{aligned} d_{itp}^{s, 0} &= I_{itp}^{s, 0} - c_{itp}^0 \\ d_{itp}^{s, k} &= \left[I_{itp}^{s, k} - c_{itp}^k \right] + \gamma_{itp}^{s, k} \cdot \left[I_{itp}^{s, k-1} - c_{itp}^{k-1} \right] \end{aligned}$$

where $\gamma_{itp}^{s, k} = \max\{0, -\varsigma \cdot (I_{itp}^{s, k} - c_{itp}^k) / d_{itp}^{s, k-1}\} \varsigma \in [1, 2]$.

Step 2: Use new multipliers to recalculate the problem, get new solutions for I_{itp}^s .

Step 3: Check the stopping criteria. If the criterion given by $\sum_{s \in B(s, P, \tau) = \Omega_{P\tau}} P^s \sum_{p=1}^{NP} \sum_{t=1}^{NT} |I_{itp}^s - c_{itp}| \leq \varepsilon_2$ is met, then stop; otherwise, go to Step 1.

APPENDIX B

Proof for Stopping Criterion: The original optimization problem is defined as

$$\begin{aligned} VP^* &= \text{Min} \left\{ f(x) + \sum_s g(y^s) \right\} \\ \text{s.t. } & x \in X \quad y^s \in Y^s \\ & y^s \leq x \quad \forall s \\ & y^s = y^{s'} \quad \text{for } s \in B(s, P, \tau) = \Omega_{P\tau}. \end{aligned} \quad (\text{B1})$$

The Lagrangian dual of the primal problem (B1) is written as

$$VL^* = \text{Max}_{\eta^s \geq 0} \left\{ \text{Min}_{\substack{x \in X, y^s \in Y^s, y^s = y^{s'} \\ \text{for } s \in B(s, P, \tau) = \Omega_{P\tau}}} \left[f(x) + \sum_s g(y^s) + \sum_s \eta^s \cdot (y^s - x) \right] \right\}. \quad (\text{B2})$$

We minimize the following Lagrangian function (B3) at the current iteration n which is a lower bound of (B2)

$$VL = \text{Min}_{\substack{x \in X, y^s \in Y^s, y^s = y^{s'} \\ \text{for } s \in B(s, P, \tau) = \Omega_{P\tau}}} \left[f(x) + \sum_s g(y^s) + \sum_s \eta^{s, n} \cdot (y^s - x) \right]. \quad (\text{B3})$$

Let VP be the objective value of a feasible solution of the original problem (B1), which is the upper bound of VP^* . Based on the above discussions

$$VL \leq VL^* \leq VP^* \leq VP. \quad (\text{B4})$$

(B3) is further decomposed into two subproblems as (B5) and (B6) corresponding to x and y , respectively:

$$VL_x = \text{Min}_{x \in X} \left[f(x) - \sum_s (\eta^{s, n} \cdot x) \right] \quad (\text{B5})$$

$$\begin{aligned} VL_y &= \text{Min} \left[\sum_s g(y^s) + \sum_s (\eta^{s, n} \cdot y^s) \right] \\ \text{s.t. } & y^s \in Y^s \\ & y^s = y^{s'} \quad \text{for } s \in B(s, P, \tau) = \Omega_{P\tau}. \end{aligned} \quad (\text{B6})$$

Based on the discussion in Section IV-C, the Lagrangian dual of (B6) is

$$\begin{aligned} VLL_y^* &= \text{Max}_{\theta^s} \left\{ \text{Min}_{y^s \in Y^s} \left[\sum_s g(y^s) + \sum_s (\eta^{s, n} \cdot y^s) + \sum_{s \in B(s, P, \tau) = \Omega_{P\tau}} (\theta^s \cdot y^s) \right] \right\}. \end{aligned} \quad (\text{B7})$$

In this paper, we minimize the following Lagrangian function at the current iteration k which is the lower bound of (B7):

$$VLL_y = \min_{y^s \in Y^s} \left[\sum_s g(y^s) + \sum_s \eta^{s,n} \cdot y^s + \sum_{s \in B(s,P,\tau)=\Omega_{P\tau}} (\theta^{s,k} \cdot y^s) \right]. \quad (\text{B8})$$

Accordingly

$$VLL_y \leq VLL_y^* \leq VL_y. \quad (\text{B9})$$

Combining (B4)–(B6) and (B9), we get

$$VLL_y + VL_x \leq VLL_y^* + VL_x \leq VL_y + VL_x \\ = VL \leq VL^* \leq VP^* \leq VP. \quad (\text{B10})$$

Thus the stopping criterion (B11) is used to terminate the iterative process since the unknown optimal solution VP^* is between $(VLL_y + VL_x)$ and VP :

$$\frac{|VP - (VLL_y + VL_x)|}{(VLL_y + VL_x)} \leq \varepsilon_1. \quad (\text{B11})$$

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Transmission Switching in Expansion Planning

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Abstract— Transmission switching (TS) is introduced to add flexibility to the transmission and generation capacity expansion planning problem. TS could improve the performance of the capacity expansion planning model and reduce the total planning cost. The capacity expansion planning problem is decomposed into a master problem and two subproblems. The master problem utilizes the candidate set for additional generating unit and transmission capacity investments to find the optimal plan throughout the planning horizon. The subproblems use the optimal plan, apply transmission switching to relieve any transmission flow violations, and calculate the optimal dispatch of generating units. The transmission network contingencies are also considered in the subproblems. The case studies exhibit the effectiveness of the proposed expansion planning approach.

Index Terms—Transmission and generation capacity expansion planning, transmission switching, mixed integer linear programming, Benders decomposition.

NOMENCLATURE

Indices:

b	Index for a load block
C	Index for a candidate generating unit or transmission line
E	Index for an existing generating unit or transmission line
h	Index for a bus
i	Index for a generating unit
j	Index for a transmission line
t	Index for a year
$\wedge$	Index for the known variables

Sets:

J_h	Set of transmission lines connected to bus h
I_h	Set of generating units connected to bus h

Parameters:

CI	Investment cost for candidate generating unit or transmission line
d	Discount rate
DT_{bt}	Duration of the load block b in year t
GCI_t	Capital generating unit investment in year t
GCT_i	Required time for the construction of unit i
GUC_t	Maximum added generating capacity in year t
GUN_t	Maximum number of generating units added in year t
LCT_t	Capital transmission line investment in year t

LCT_j	Required construction time for the transmission line j
LUC_t	Maximum transmission line capacity to be added in year t
LUN_t	Maximum added number of transmission lines in year t
NB	Number of load blocks
NCG	Number of candidate generating units
NCL	Number of candidate transmission lines
NEG	Number of existing generating units
NEL	Number of existing transmission lines
NH	Number of buses
NT	Number of years
OC_{ibt}	Operating cost of the generating unit i at load block b in year t
PD_{hbt}	Load demand at bus h at load block b in year t
UX_{ibt}	Contingency state of the generating unit i at load block b in year t
UY_{jbt}	Contingency state of the transmission line j at load block b in year t
γ_j	Susceptance of the transmission line j
ε	Small positive and predefined threshold

Variables:

PG_{ibt}	Dispatched capacity of the generating unit i at load block b in year t
PL_{jbt}	Power flow on the transmission line j at load block b in year t
$SL_{hbt,1}, SL_{hbt,2}$	Non-negative Slack variables for power mismatch at bus h at load block b in year t
X_{it}	Investment state of the generating unit i in year t
Y_{jt}	Investment state of transmission line j in year t
Z_{jbt}	Switching state of the transmission line j at load block b in year t
δ_{mbt}	Voltage angle of bus m at load block b in year t
λ, μ, π	Dual variables.

I. INTRODUCTION

SWITCHING of power system elements can help ISOs maintain the system security and reduce operation costs. In comparison with existing control methods such as generating unit rescheduling or load shedding [1,2], transmission switching (TS) can provide additional economical advantages. Several TS approaches were presented in the literature to encompass various operational modes of

power systems. In [3], TS was used as a corrective action to mitigate transmission flow violations. In [4]-[7], TS was used to model the power system security in contingency cases. TS was used in [8] as a congestion management tool. However, TS can provide economic benefits which was first introduced in [9] in a market context. The application of TS in reducing the production cost was investigated in [10], and was further developed in [11] to examine the effects of network topology changes on nodal prices, load payments, generation revenues, congestion costs, and flowgate prices. In [12] a model was proposed to add contingencies to the model in [10]. These studies indicated that the switching could provide additional control actions for voltage stability, congestion management, transmission loss reduction, production cost minimization, and the enhancement of system security. However, the TS applicability to the power system planning was not addressed.

Power system planning is the science of determining the optimal place, size, and time for adding new resources to power systems. Previous studies investigated generation and transmission expansion planning methodologies in competitive market environments. The most common planning methods are based on mathematical optimization such as branch and bound, linear programming, and Benders decomposition [13]-[21]. Also heuristic approaches, such as genetic algorithms, fuzzy-sets, simulated annealing, expert systems, and game-theoretic methods [22]-[30] were used to solve the expansion planning problem. The market-based planning in power systems considers economics, security, and reliability constraints and analyzes the risk of planning strategies based on uncertainties [31]-[35]. Using Lagrangian relaxation and Benders decomposition, the impact of transmission security on generation resource planning was discussed [36]. The coordination of transmission expansion planning with the competitive generation capacity planning was presented in [37]. In [38], a very constructive proposal was offered on the interaction of generation and transmission investments in transmission planning. In [39], the long-term transmission expansion planning problem in a competitive pool-based electricity market was modeled. In this model, a number of scenarios based on the future system demand were defined and the optimal expansion planning was simulated by the maximization of the aggregated social welfare. A bilevel model for transmission expansion planning within a market environment was proposed in [40]. The minimization of the network investment was considered in the upper level, while the lower level included pool trading constraints.

The objective of a generation company (GENCO) or a transmission company (TRANSCO) is to maximize its profit over the planning horizon. However, when the ISO performs the planning, the objective will be replaced by the minimization of investment and operating costs. In this paper, it is assumed that the GENCOs and TRANSCOs have already submitted their candidate expansion proposals to the ISO. The ISO will solve the expansion planning problem to satisfy the system constraints based on the candidate set of components submitted by the participating companies.

This paper presents a TS coordinated expansion planning model. The planning is a long-term problem that is solved over

an extended period of time. TS is a short-term operation problem. The two problems are solved separately, considering the associated time periods. The important point is to link these two problems in a way that the impact of TS on planning can be observed. This task is accomplished by using the security check and the optimal operation subproblems in Fig. 1. The TS application could reduce the total planning cost and possibly defer the planning of the candidate units and transmission lines. In this situation the transmission congestion in the system can vary. A corrective/preventive scheme is used to handle transmission line and generating unit contingencies. The security check subproblem performs corrective actions, while the preventive actions are considered in the master problem. Our proposed approach uses a deterministic criterion to consider contingencies. A future stochastic market-based expansion planning study will explore the effect of random outages of generating units and transmission lines in addition to the long-term load forecast errors, where the Monte Carlo simulation will be used to identify scenarios and the proposed deterministic model will be solved in each scenario.

The rest of the paper is organized as follows. Section II presents the model outline of the proposed approach, while Section III formulates different parts of it. Section IV conducts the numerical simulations and in detail discusses a six-bus, the IEEE 118-bus and an 1168-bus systems. Finally, concluding remarks are presented in Section V.

II. PROPOSED MODEL OUTLINE

Fig. 1 depicts the proposed coordinated generation and transmission expansion planning model. The objective of this problem is to minimize the investment cost, for new generating units and transmission lines, in addition to operating costs. This objective is subject to different security-based planning and operation constraints.

Fig. 1 Proposed expansion planning using TS

In this paper, Benders decomposition is used to decompose the expansion planning problem. Benders decomposition is mathematically sound and can easily be applied to large-scale systems. The optimality of Benders decomposition as well as its applicability to power system problems in practical cases are discussed in [41]-[44]. Also in [2], the practical

applications of Benders decomposition are discussed in detail, where it is explained that the most suitable approach to solve the multi-period expansion planning problem is to use the Benders decomposition. The Benders decomposition provides the iterative solution of the mixed integer linear programming problem in a distributed manner. The decomposed planning model includes the optimal investment plan as the master problem, and the security and the optimal operation of the system as the two subproblems. The master problem utilizes the candidate set of generating units and transmission lines to find the optimal investment plan. The security check subproblem examines this plan for satisfying the base case and the security constraints. The optimal operation subproblem inspects the operating cost of the plan. TS is used in the security check and the optimal operation subproblems to enhance the feasibility and the optimality of the proposed problem, respectively. Integer linear programming (ILP) is used to model the master problem, while the subproblems are LP models. A typical set of planning constraints includes

- Capital investment funds
- Projected resource and line capacity
- Maximum number of generating units and transmission lines to be added
- Construction time of the candidate investments

A typical set of operation constraints includes

- Power balance
- Transmission line flow limits
- Generation limits

The approach is presented as follows.

A. Master problem

The master problem calculates the investment plan for generating units and transmission lines based on the initial set of candidates when considering generation and transmission expansion constraints. The lower bound for the original MIP planning problem is determined by the value of the master problem objective at each iteration. The variables in the master problem are binary and constraints are linear. So the master problem is in the ILP format.

B. Subproblems

The investment plan calculated in the master problem is submitted to the subproblems. The security check subproblem checks whether the proposed plan satisfies the operation constraints. This subproblem would satisfy the power balance at every bus while preserving base case and contingency constraints. If any of the constraints are violated, a feasibility cut is formed and added to the master problem for the solution of the next iteration of the expansion planning problem. This iterative process will continue until a secure plan is achieved.

The optimal operation subproblem is used to check the minimum cost of solution. This subproblem checks the optimality by calculating the upper bound of the original MIP planning problem's objective function and comparing it with its lower bound, which is already calculated in the master problem. If the proposed plan is not optimal, Benders cuts will be formed and added to the master problem for solving the next iteration.

C. TS

TS is used in both subproblems to minimize the operating costs as well as the transmission security violations. The TS binary variables are determined in the master problem and treated as constants in the subproblems. The utilization of TS states in the proposed cuts will help utilize candidate generating units and transmission lines in the planning options. The switchable line states appear as variables in the master problem, but they are governed by dual values in the subproblems.

D. Cuts

In the proposed approach two types of cuts are used. The first one is a feasibility cut which is generated in the security check subproblem. The feasibility cut indicates that the security violations can be mitigated by readjusting the investment plan in each planning year as well as the state of switchable lines in the operation periods. This cut represents the coupling of the proposed investment plan and adjustments in the state of switchable lines. The dual variables in the feasibility cut are the incremental reduction in the load balance violations. The second one is an optimality cut that is generated in the optimal operation subproblem. The optimality cut would limit the range of master problem objective to make it closer to the objective function of the expansion planning problem calculated prior to the decomposition. The optimality cut indicates that the objective value of the expansion planning problem can be decreased by modifying the investment plan in addition to the state of switchable lines. Similar to the feasibility cut, this cut represents the coupling of adjustments in the proposed investment plan and the state of switchable lines. The dual variables in the optimality cut are the incremental reduction in the objective function of the optimal operation subproblem.

E. Solution Procedure

The binary switching variables in the master problem are governed by Benders cuts generated in the subproblems. On the other hand, the switching variables affect the investment plans. So the solution of the larger time scale is guided by the smaller time scale problem, and the solution of the smaller time scale problem is guided by the cuts produced at each iteration. The planning solution procedure is given as follows.

- 1) Solve the planning master problem by considering candidate generating units and transmission lines. There will be no Benders cut in the first iteration of the master problem.
- 2) Given the proposed plan in the master problem, check the feasibility of system constraints. If the subproblem is feasible, proceed to Step 3. Otherwise, form the Benders cut and return to the master problem.
- 3) Minimize the operating cost by considering the system constraints. Compare the solution value, i.e., an upper bound, with the objective of master problem, i.e. a lower bound. If the difference is larger than a predefined threshold, form the Benders cuts and return to the master problem for the next iteration. Otherwise, consider the proposed plan as optimal.

III. PROBLEM FORMULATION

The objective of the expansion planning problem is to minimize the total cost of the system while satisfying the system security and reliability constraints. The total cost includes the investment cost of new generating units and transmission lines plus the system operating cost. This objective is formulated as (1), and is subject to planning and operation constraints.

$$\begin{aligned} \text{Min } PP = & \sum_{t=1}^{NT} \sum_{i=1}^{CG} \frac{CI_{it} (X_{it} - X_{i(t-1)})}{(1+d)^{(t-1)}} \\ & + \sum_{t=1}^{NT} \sum_{j=1}^{CL} \frac{CI_{jt} (Y_{jt} - Y_{j(t-1)})}{(1+d)^{(t-1)}} \\ & + \sum_{t=1}^{NT} \sum_{b=1}^{NB} \sum_{i=1}^{NG} \frac{DT_{bt} OC_{ibt} PG_{ibt}}{(1+d)^{(t-1)}} \end{aligned} \quad (1)$$

The solution of this problem would determine the size, the location, and the time for adding new generating units and transmission lines in an economical way that ensures the system capability to meet the anticipated load growth in the future. Using the Benders decomposition, the problem is decomposed into a master problem and two subproblems. The master problem provides the optimal plan and the subproblems provide solutions for the security check and the optimal operation.

A. Optimal Plan

The objective of the optimal investment planning problem is to minimize the investment cost of new generating units and transmission lines.

$$\begin{aligned} \text{Min } MP \\ MP \geq & \sum_{t=1}^{NT} \sum_{i=1}^{CG} \frac{CI_{it} (X_{it} - X_{i(t-1)})}{(1+d)^{(t-1)}} + \sum_{t=1}^{NT} \sum_{j=1}^{CL} \frac{CI_{jt} (Y_{jt} - Y_{j(t-1)})}{(1+d)^{(t-1)}} \end{aligned} \quad (2)$$

This objective is subject to the planning constraints (3)-(12). The generating unit constraints include capital investment funds in a planning year (4), anticipated resource capacity in a planning year (5), maximum number of generating units to be added at a planning year (6), and the construction time of the candidate investment (7). Similarly, the transmission line constraints are capital investment funds in a planning year (9), anticipated transmission line capacity in a planning year (10), maximum number of transmission lines to be added at a planning year (11), and the construction time of the candidate investment (12). Constraint (3) specifies that once a generating unit is in place, its investment state will be 1 in the following years. The same constraint exists for transmission lines, which is presented by (8).

$$X_{i(t-1)} \leq X_{it} \quad (i = 1, \dots, NCG) \quad (t = 2, \dots, NT) \quad (3)$$

$$\sum_{i=1}^{CG} CI_{it} (X_{it} - X_{i(t-1)}) \leq GCI_t \quad (t = 1, \dots, NT) \quad (4)$$

$$\sum_{i=1}^{CG} Cap_i (X_{it} - X_{i(t-1)}) \leq GUC_t \quad (t = 1, \dots, NT) \quad (5)$$

$$\sum_{i=1}^{CG} (X_{it} - X_{i(t-1)}) \leq GUN_t \quad (t = 1, \dots, NT) \quad (6)$$

$$X_{it} = 0 \text{ if } t < GCT_i \quad (i = 1, \dots, NCG) \quad (t = 1, \dots, NT) \quad (7)$$

$$Y_{j(t-1)} \leq Y_{jt} \quad (j = 1, \dots, NCL) \quad (t = 2, \dots, NT) \quad (8)$$

$$\sum_{j=1}^{CL} CI_{jt} (Y_{jt} - Y_{j(t-1)}) \leq LCI_t \quad (t = 1, \dots, NT) \quad (9)$$

$$\sum_{j=1}^{CL} Cap_j (Y_{jt} - Y_{j(t-1)}) \leq LUC_t \quad (t = 1, \dots, NT) \quad (10)$$

$$\sum_{j=1}^{CL} (Y_{jt} - Y_{j(t-1)}) \leq LUN_t \quad (t = 1, \dots, NT) \quad (11)$$

$$Y_{jt} = 0 \text{ if } t < LCT_j \quad (j = 1, \dots, NCL) \quad (t = 1, \dots, NT) \quad (12)$$

The master problem will determine the optimal investment plan and the lower bound for the original MIP planning problem. The optimality cuts will help minimize investment and operation costs in the master problem. The states of switchable transmission lines are also examined in this problem. Here, the Benders cuts provide the state of switchable lines to the master problem.

B. Security Check

Given the proposed plan in the master problem, as well as the state of switchable lines, the security check subproblem minimizes the potential system violations. This task is accomplished by introducing slack variables in the power balance equation at each bus. The objective is to minimize the sum of non-negative slack variables.

$$\text{Min } v_t = \sum_{b=1}^{NB} \sum_{h=1}^{NH} (SL_{hbt,1} + SL_{hbt,2}) \quad (13)$$

$$\begin{aligned} \sum_{i \in I_h} PG_{ibt}^E + \sum_{i \in I_h} PG_{ibt}^C - PD_{hbt} - \sum_{j \in J_h} PL_{jbt}^E - \sum_{j \in J_h} PL_{jbt}^C \\ + SL_{hbt,1} - SL_{hbt,2} = 0 \end{aligned} \quad (14)$$

(h = 1, \dots, NH) (b = 1, \dots, NB) (t = 1, \dots, NT)

Equation (14) shows the power mismatch at bus h . In this equation, existing and candidate lines are shown with superscripts E and C , respectively. Set J_h includes the lines connected to bus h which are labeled as either the 'to bus' or the 'from bus' in the set.

This problem is subject to existing and candidate generating unit and transmission line constraints. These constraints represent the capacity of existing and candidate generating units (18)-(19), existing transmission line flows (20)-(23), candidate transmission line flows (24)-(27), and phase angle of reference bus (28).

$$X_{it} = \hat{X}_{it} \quad (i = 1, \dots, NCG) \quad (t = 1, \dots, NT) \quad (15)$$

$$Y_{jt} = \hat{Y}_{jt} \quad (j = 1, \dots, NCL) \quad (t = 1, \dots, NT) \quad (16)$$

$$Z_{jbt} = \hat{Z}_{jbt} \quad (j = 1, \dots, NEL) \quad (b = 1, \dots, NB) \quad (t = 1, \dots, NT) \quad (17)$$

$$0 \leq PG_{ibt}^E \leq PG_i^{\max, E} UX_{ibt}^E \quad (i = 1, \dots, NEG) \quad (b = 1, \dots, NB) \quad (t = 1, \dots, NT) \quad (18)$$

$$0 \leq PG_{ibt}^C \leq PG_i^{\max, C} X_{it} UX_{ibt}^C \quad (i = 1, \dots, NCG) \quad (b = 1, \dots, NB) \quad (t = 1, \dots, NT) \quad (19)$$

$$PL_{jbt}^E - \gamma_j (\delta_{mbt}^E - \delta_{nbt}^E) - M_j^E (1 - Z_{jbt}) - M_j^E (1 - UY_{jbt}^E) \leq 0 \quad (20)$$

(j = 1, ..., NEL) (b = 1, ..., NB) (t = 1, ..., NT)

$$PL_{jbt}^E - \gamma_j (\delta_{mbt}^E - \delta_{nbt}^E) + M_j^E (1 - Z_{jbt}) + M_j^E (1 - UY_{jbt}^E) \geq 0 \quad (21)$$

(j = 1, ..., NEL) (b = 1, ..., NB) (t = 1, ..., NT)

$$PL_{jbt}^E \leq PL_j^{\max, E} Z_{jbt} UY_{jbt}^E \quad (22)$$

(j = 1, ..., NEL) (b = 1, ..., NB) (t = 1, ..., NT)

$$-PL_{jbt}^E \leq PL_j^{\max, E} Z_{jbt} UY_{jbt}^E \quad (23)$$

(j = 1, ..., NEL) (b = 1, ..., NB) (t = 1, ..., NT)

$$PL_{jbt}^C - \gamma_j (\delta_{mbt}^C - \delta_{nbt}^C) - M_j^C (1 - Y_{jt}) - M_j^C (1 - UY_{jbt}^C) \leq 0 \quad (24)$$

(j = 1, ..., NCL) (b = 1, ..., NB) (t = 1, ..., NT)

$$PL_{jbt}^C - \gamma_j (\delta_{mbt}^C - \delta_{nbt}^C) + M_j^C (1 - Y_{jt}) + M_j^C (1 - UY_{jbt}^C) \geq 0 \quad (25)$$

(j = 1, ..., NCL) (b = 1, ..., NB) (t = 1, ..., NT)

$$PL_{jbt}^C \leq PL_j^{\max, C} Y_{jt} UY_{jbt}^C \quad (26)$$

(j = 1, ..., NCL) (b = 1, ..., NB) (t = 1, ..., NT)

$$-PL_{jbt}^C \leq PL_j^{\max, C} Y_{jt} UY_{jbt}^C \quad (27)$$

(j = 1, ..., NCL) (b = 1, ..., NB) (t = 1, ..., NT)

$$\delta_{ref} = 0 \quad (28)$$

In the above formulation, the constraints on candidate generating units and transmission lines include the associated binary variable, which is already determined in the master problem. The state of switchable transmission lines is included in the existing transmission flow constraints (20)-(23). So, whenever a transmission line is switched off its associated switchable state is zero and the transmission line will be completely removed from the network. A subset of existing transmission lines is usually considered as switchable. Therefore, for the remaining and non-switchable lines the switching state (binary variable) will be equal to 1 in the expansion planning problem. The transmission line j is between buses m and n with a transmission flow from bus m to bus n . In constraints (20), (21), (24) and (25), a large constant value, i.e. M , is used to satisfy the relaxation of associated constraints when they would be eliminated. This disjunctive parameter would be larger than a minimum value and should not be very large. The solution of the planning problem is sensitive to the value of this parameter, where in [45] it is shown that large values of disjunctive parameter could limit the validity of the Benders decomposition results. In [21], an effective approach is presented to calculate this parameter, where the disjunctive parameter is increased along the Benders iterations. However in this paper, it is assumed that the disjunctive parameter of each line has a constant value, which is equal to its minimum allowable value. In Appendix, the minimum allowable values of disjunctive parameters are calculated for transmission lines.

The security check subproblem is solved for the base case and contingencies. During the contingencies, transmission lines can operate at their emergency ratings. So, $PL_j^{\max}$ will be adjusted accordingly. The contingency state of the element that is on outage will be zero. In the base case, this parameter will

be one. The security check subproblem performs corrective actions to mitigate the violations. Those contingencies that cannot be mitigated with corrective actions are dealt with by preventive actions in the next iteration of the master problem.

If the proposed objective is zero, the problem will proceed to the optimal operation subproblem. Otherwise, the Benders cut (29) will be formed and added to the master problem for the next iteration.

$$v_t + \left\{ \begin{array}{l} \sum_{i=1}^{CG} \lambda_{it} (X_{it} - \hat{X}_{it}) + \sum_{j=1}^{CL} \mu_{jt} (Y_{jt} - \hat{Y}_{jt}) \\ + \sum_{j=1}^{NS} \sum_{b=1}^{NB} \pi_{jbt} (Z_{jbt} - \hat{Z}_{jbt}) \end{array} \right\} \leq 0 \quad (29)$$

where λ , μ , and π are dual values of constraints (15), (16) and (17), respectively. This cut points out that the stated violations could be mitigated by changing the investment plan in addition to the state of switchable lines. In fact, this cut calculates the capacity signals for the investment of new generating units and transmission lines in case the existing ones cannot satisfy the system feasibility. The Benders cut will be formed for each violated case and added to the master problem. The iterative procedure continues until a secure plan that satisfies the system feasibility is achieved in the base case and contingencies.

C. Optimal Operation

After satisfying the feasibility of the plan due to system constraints, the optimal operation will check the optimality of the solution cost. The objective of the optimal operation problem is to minimize the operating cost for every year and load block as

$$\text{Min } w_{bt} = \sum_{i=1}^{NG} \frac{DT_{bt} OC_{ibt} PG_{ibt}}{(1+d)^{(t-1)}} \quad (30)$$

This objective is subject to (15)-(28). The problem is solved for the base case in which contingency parameters are equal to 1. The solution provides the upper bound of the objective function of expansion planning. This upper bound is used to check the optimality of the solution. So the stopping criterion is defined based on this solution. If the proposed plan is not optimal, a Benders cut will be formed and added to the master problem for the next iteration. The proposed Benders cut (31) would restrict the lower bound of objective function in the master problem. Here, λ , μ , and π are dual values of (15), (16), and (17), respectively.

The iterative process between the master problem and subproblems will continue until an optimal solution of the expansion planning problem is calculated. The problem feasibility is ensured via the security check subproblem, while the optimality is guaranteed by comparing the solutions of the master problem and the optimal operation subproblem at each iteration. The solution of the master problem is the lower bound of the optimal solution. The upper bound of the optimal solution is found by using the results of optimal operation subproblem. The optimal solution is obtained when lower and upper bounds are close enough. These bounds are utilized to form an effective convergence criterion in (32).

$$\begin{aligned}
MP \geq & \sum_{t=1}^{NT} \sum_{b=1}^{NB} \hat{w}_{bt} + \sum_{t=1}^{NT} \sum_{i=1}^{CG} \frac{CI_{it} (X_{it} - X_{i(t-1)})}{(1+d)^{(t-1)}} \\
& + \sum_{t=1}^{NT} \sum_{j=1}^{CL} \frac{CI_{jt} (Y_{jt} - Y_{j(t-1)})}{(1+d)^{(t-1)}} \\
& + \sum_{t=1}^{NT} \sum_{i=1}^{CG} \lambda_{it} (X_{it} - \hat{X}_{it}) \\
& + \sum_{t=1}^{NT} \sum_{j=1}^{CL} \mu_{jt} (Y_{jt} - \hat{Y}_{jt}) \\
& + \sum_{t=1}^{NT} \sum_{j=1}^{NS} \sum_{b=1}^{NB} \pi_{jbt} (Z_{jbt} - \hat{Z}_{jbt})
\end{aligned} \quad (31)$$

$$\frac{PP - MP}{PP + MP} < \varepsilon \quad (32)$$

The planning stage is performed yearly while the operation stage is carried out for load blocks. The contingencies would last for the entire load block in a year. However, there are no limitations on the length of load blocks which can be chosen as any period of time from hours to months. The choice will be a tradeoff between the accuracy and the simplicity in the execution of the proposed model. However, the choice of load blocks would play an important role in the proposed model. This issue will be addressed in our future study.

IV. NUMERICAL SIMULATIONS

Three case studies consisting of a six-bus system, the IEEE 118-bus system and an 1168-bus system are analyzed. The proposed method was implemented on a 2.4-GHz personal computer using CPLEX.

A. Six-Bus System

The six-bus system is shown in Fig. 2. A 10-year planning horizon is considered. The system data for generating units and transmission lines are given in Tables I and II, respectively. In Table III the forecasted yearly peak load is listed. This load is distributed at the rate of 40%, 30% and 30% among buses 3, 4 and 5, respectively. To simplify the calculations, four load blocks are considered annually. The duration and quantity of load blocks in the first year are given in Table IV. The load blocks in subsequent years will change in proportion to those in Year 1. A set of 4 candidate generating units and 4 candidate transmission lines are considered as planning options in Tables I and II. The construction time for generating units is considered to be 3 years, while it is less than one year for the transmission lines. It is assumed that there are no annual limitations on capital investments or the number of generating units and transmission lines. The discount rate is assumed to be 0. Three transmission lines 1-4, 2-4, and 4-5 are considered as switchable in the following four planning cases:

Case 1: Base case planning

Case 2: Transmission line 5-6 outage in load block 3 of year 4

Case 3: Generating unit 3 outage in load block 1 of year 6

Case 4: Simultaneous outages considered in Cases 2 and 3

The cases are discussed next.

Fig. 2 Six-bus system

TABLE I
GENERATING UNIT DATA OF SIX-BUS SYSTEM

Unit No.	Bus No.	Generating Capacity (MW)	Investment Cost (\$/kW)	Operation Cost (\$/MWh)
1	1	100	Existing	15
2	2	100	Existing	18
3	6	50	Existing	23
4	1	100	200	15
5	2	80	270	21
6	2	60	250	24
7	3	20	250	24

TABLE II
TRANSMISSION LINE DATA OF SIX-BUS SYSTEM

Line No.	From Bus	To Bus	X (p.u.)	Capacity (MW)	Investment Cost (\$/kW)
1	1	2	0.17	80	Existing
2	2	3	0.037	70	Existing
3	1	4	0.258	140	Existing
4	2	4	0.197	100	Existing
5	4	5	0.037	50	Existing
6	5	6	0.14	140	Existing
7	3	6	0.018	130	Existing
8	1	2	0.17	80	20
9	2	3	0.037	70	24
10	1	4	0.258	140	30
11	5	6	0.14	140	14

TABLE III
YEARLY PEAK LOAD FORECAST OF SIX-BUS SYSTEM

Year	1	2	3	4	5
Peak (MW)	209	225	231	243	269
Year	6	7	8	9	10
Peak (MW)	297	307	315	324	330

TABLE IV
LOAD BLOCKS IN THE FIRST YEAR

Block	1	2	3	4
Duration (h)	87	2541	4380	1752
Load (MW)	209	192	167	150

Case 1: The 10-year expansion planning is considered without considering the TS. According to this plan, line 2-3 is installed in the first year. Also, generating units 6 and 7 are added in years 5 and 8, respectively. At the first year, existing units 1,2,3 try to satisfy the system load while maintaining the feasibility of transmission flows. Here, cheaper units 1 and 2

are dispatched at their maximum capacity and the remaining load is supplied by unit 3. However, due to the congestion of line 2-3, unit 2 cannot increase its generation to its capacity. So the more expensive unit 3 would increase its generation, which increases the operating cost. Accordingly, the candidate line 2-3 is installed at the first year. This installation leads to an increase in the transmission capacity between buses 2 and 3, which allows unit 2 to increase its generation to its capacity in subsequent years.

The new system topology satisfies the system load while the system load is less than the total installed capacity in the system, i.e., years 1-4. In year 5 the system would need to install a new generation capacity to help satisfy the additional load. So, unit 6 is placed at bus 2 which can transfer more power in conjunction with the installation of line 2-3. Two options (i.e. either candidate unit 5 or 6) are available for the installation of a unit in bus 2. Unit 5 is more economical while unit 6 requires a less investment cost. Considering the remaining 5 years, the algorithm chooses unit 6. Similarly in year 8, another unit is installed. The cheapest generating candidate from the operation viewpoint is unit 4, and the one from the planning viewpoint is unit 7. However, considering the remaining two years in the planning horizon, unit 7 is selected as being more economical. In this case, unit 5 is not a good option since the larger generation in bus 2 may lead to the congestion on line 2-3. The total cost in this case is \$366.3M.

TABLE V
CANDIDATE UNIT INSTALLATION YEAR OF SIX-BUS SYSTEM

Candidate Unit	Case 1	Case 2	Case 3	Case 4
4	-	5	6	6
5	-	-	-	-
6	5	-	-	-
7	8	-	5	5

TABLE VI
CANDIDATE UNIT INSTALLATION YEAR OF SIX-BUS SYSTEM USING TS

Candidate Unit	Case 1	Case 2	Case 3	Case 4
4	5	5	6	6
5	-	-	-	-
6	-	-	-	-
7	-	-	5	5

TABLE VII
CANDIDATE LINE INSTALLATION YEAR OF SIX-BUS SYSTEM

Candidate Line	Case 1	Case 2	Case 3	Case 4
1-2	-	-	6	-
2-3	1	1	1	1
1-4	-	7	6	6
5-6	-	4	-	4

TABLE VIII
CANDIDATE LINE INSTALLATION YEAR OF SIX-BUS SYSTEM USING TS

Candidate Line	Case 1	Case 2	Case 3	Case 4
1-2	-	-	-	-
2-3	1	1	1	1
1-4	9	7	6	6
5-6	-	4	-	4

The TS application in Case 1 will result in a different expansion plan, where unit 4 is installed at year 5 and lines 2-3 and 1-4 are installed at years 1 and 9, respectively. The installation of line 2-3 at year 1 will again relieve the congestion on line 2-3 and increase the dispatchability of units at buses 1 and 2. At year 5, unit 4 is chosen when the system needs to install additional generation capacity. This unit is the most economical candidate unit from operation viewpoint. With the installation of unit 4 at bus 1, most of the system load will be supplied. The additional dispatch at bus 1 would lead to an increase in line flows with a possible congestion. TS is used to mitigate the congestion. For example when the load in year 5 is higher than 215 MW, the feasibility constraints cannot be satisfied. The constraints are satisfied with the switching of line 2-4. Here, the total cost is dropped by 5.56% to \$345.9M.

Case 2: In this case, the outage of line 5-6 in year 4 is considered. Similar to Case 1, line 2-3 is installed at year 1. With the possible outage of line 5-6, the installation of candidate line 5-6 will be necessary. Furthermore, the candidate line 1-4 is installed in year 7 with the largest investment cost among candidate lines. However, the line will enhance the dispatch of energy generated by cheap units at bus 1. The total cost in this Case is \$347.9M which is higher than that in Case 1.

Using TS, a similar expansion plan is proposed, i.e., the installation of unit 4 at year 5 and lines 2-3, 1-4, and 5-6 in years 1, 7, and 4, respectively. The line switching does not change the proposed plan in this case. However, the total cost is reduced to \$346.4M. The lower total cost is mainly due to the switching of line 2-4. When the line is switched off, the flows on lines 1-2 and 1-4 will be less dependent on one another. So both lines can transfer more power, which would result in the additional dispatch of units at bus 1. Since the cheapest units are at bus 1, the additional dispatch of these units will reduce the total cost.

Case 3: The outage of unit 3 at year 6 would change the proposed plan in Case 1. Like previous cases, new generation capacity is added at year 5. The proposed plan requires the installation of unit 7 at year 5 and subsequently unit 4 at year 6. The installation of unit 4 would increase the installed capacity. Also, unit 7 is added to satisfy the loads in buses 3 and 5. The installation of unit 7 is a preventive action to handle the outage of unit 3. The installed lines are 1-2, 2-3 and 1-4 in years 6, 1 and 6, respectively. Line 2-3 is installed to increase the dispatchability of units at buses 2 and 3, while lines 1-2 and 1-4 are installed to enhance the dispatchability of units at bus 1. The TS application would eliminate the previous installation of line 1-2 at year 6. The previous line flow violations that required the installation of line 1-2 are alleviated by the switching of lines 2-4 and 4-5. The total cost is \$350.6M, which is 0.4% cheaper when using TS. This improvement is due to the elimination of candidate line 1-2 in the planning horizon as well as a decrease in the operating cost. This study demonstrates that the application of TS could result in a similar but cheaper expansion planning.

Case 4: The expansion plan will not be influenced by TS when

considering simultaneous outages of line 5-6 in year 4 and unit 3 in year 6. The expansion plan includes the installation of unit 4 at year 6, unit 7 at year 5, and lines 2-3, 1-4 and 5-6 at years 1, 6, and 4, respectively. The installation of unit 7 is a preventive action for the possible outage of unit 3, while the installation of line 11 is a preventive action for the possible outage of line 5-6. The TS application will not alter the proposed expansion plan, but will reduce the total cost by 0.5%.

B. IEEE 118-Bus System

A modified IEEE 118-bus system is used to study the expansion planning problem with TS. The system has 118 buses, 54 units and 186 branches. The data is given in motor.ece.iit.edu/data/Planning_118.xls. The candidate units and lines data are presented in Tables IX and X, respectively. The load growth rate is at 7%. The following three cases are analyzed:

Case 1: Base case planning

Case 2: Effect of discount rate on the planning solution

Case 3: Effect of the number of switchable lines on the planning solution

In Cases 1 and 3, the discount rate is assumed to be 10%, while in Case 2 the discount rate is changed to investigate its effect on the planning solution. In Cases 1 and 2 the effect of TS on planning is analyzed, where ten lines are considered as switchable. The list of these switchable lines is presented in Table XI. In Case 3 the planning problem is solved for a variable number of switchable lines.

TABLE IX
CANDIDATE UNIT DATA OF IEEE 118-BUS SYSTEM

Unit No.	Bus No.	Generating Capacity (MW)	Investment Cost (\$/kW)	Operation Cost (\$/MWh)
1	10	200	15	250
2	12	200	15	250
3	25	200	15	250
4	26	200	15	250
5	80	200	15	250
6	89	200	15	250
7	18	100	18	120
8	32	100	18	120
9	55	100	18	120
10	56	100	18	120
11	62	100	18	120
12	74	20	38	50
13	74	20	38	50
14	90	20	38	50
15	103	20	38	50
16	103	20	38	50

TABLE X
CANDIDATE TRANSMISSION LINE DATA OF IEEE 118-BUS SYSTEM

Line No.	From Bus	To Bus	X (p.u.)	Capacity (MW)	Investment Cost (\$/kW)
1	30	38	0.054	100	30
2	77	82	0.0853	100	30
3	110	111	0.0755	100	30
4	20	21	0.0849	100	30
5	17	113	0.0301	100	30

TABLE XI
SWITCHABLE LINE DATA OF IEEE 118-BUS SYSTEM

Switchable Line No.	Line No.	From Bus	To Bus	X (p.u.)	Capacity (MW)
1	30	23	24	0.0492	100
2	54	30	38	0.0540	100
3	65	47	49	0.0625	100
4	115	70	75	0.1410	100
5	151	80	97	0.0934	100
6	159	99	100	0.0813	100
7	164	100	104	0.2040	100
8	78	54	56	0.0096	100
9	90	60	61	0.0135	500
10	184	12	117	0.1400	100

Case 1: The base case planning for the IEEE-118 bus system is solved as a coordinated generation and transmission expansion planning problem. At first we disregard the TS option. The proposed plan is shown in Tables XII and XIII for unit and line installations, respectively. In the first four years of planning, loads are satisfied and there is no need to install any new units or lines. The installed generation capacity of the system is 5,850 MW. In these four years, the congestion occurs in lines 8 and 96. However at year 5, due to the congestion in line 38 the system cannot satisfy its load, though the system has enough installed capacity. To alleviate this congestion and transfer the required power to the loads, the candidate units 2 and 4 are installed. The installations will mitigate the congestion of lines 8, 96 and 38 and the system will be able to meet the load. At the subsequent years 6 and 7, candidate units 5 and 3 are installed, respectively.

TABLE XII
CANDIDATE UNIT INSTALLATION YEAR FOR IEEE 118-BUS SYSTEM IN CASE 1

Candidate Unit	Ignoring TS	Considering TS
1	-	7
2	5	5
3	7	6
4	5	-
5	6	5
6	-	-
7	-	-
8	10	-
9	9	10
10	10	10
11	-	10
12	10	10
13	10	10
14	10	10
15	-	-
16	-	-

TABLE XIII
CANDIDATE LINE INSTALLATION YEAR FOR IEEE 118-BUS SYSTEM IN CASE 1

Candidate Line	Ignoring TS	Considering TS
1	7	-
2	-	-
3	-	-
4	-	-
5	10	-

The installation of unit 5 at year 6 offers physical and economical advantages. On the other side, the installation of unit 3 at year 7 will mitigate the congestion in lines 31, 38 and 51. The candidate units 2, 4 and 5 represent expensive investments, but are necessary to provide sufficient generation capacity and transmission flow feasibility. Also the candidate line 1 is installed at year 7 to mitigate the congestion. Accordingly, there will be no need to install new components at year 8. However, at year 9 the candidate unit 9 is installed and subsequently the units 8, 10, 12, 13 and 14 are installed at the last planning year. Also, the candidate line 5 is installed to increase the transfer capacity of the system. Considering the results, we conclude that the system is well-designed and the transmission lines offer a sufficient capacity to transfer the generated power most often.

TS provides quite different results. The candidate units 5 and 3 are installed one year earlier. The candidate units 4 and 8 are not installed and instead units 1 and 11 are installed at years 7 and 10, respectively. Also, the installation of unit 9 is delayed by one year, while the installation of other candidate units is remained the same, i.e. unit 2 is installed at year 5 and units 10, 12, 13 and 14 are installed at year 10. Accordingly, the generation investment cost is decreased by 0.35%. The use of TS eliminates the line investment in this case, as shown in Table XIII. Also, TS enhances the power transfer capability by allowing existing transmission lines to transfer additional power. Here, the lines 7, 8, 9 and 36 are congested at years 7 to 10. Also line 96 is congested at years 1 to 5. The TS applications at certain load blocks will mitigate the congestions and enhances the system feasibility. Accordingly, the operating cost of the system is slightly increased. However, the proposed TS plan will reduce the total cost by 0.04%. As noted in the Introduction, TS may defer generation and transmission investments. Considering the obtained results, the installation of candidate unit 9 is deferred, while the candidate units 3 and 5 are installed earlier than the base case solution.

Case 2: The sensitivity of the proposed plan to the discount rate is investigated. Generally, the discount rate is used in the calculation of the net present value and capacity payment for new generating unit and transmission line investments. It is clear when the discount rate is higher the investment candidates with higher capital costs become inferior. In the real world, investors may use different discount rates in their planning studies which would depend on their financial situation and business strategies. However, in this case the discount rate is assumed to be the same for all candidate units and lines. The discount rates of 10%, 5% and 0% are considered. The candidate units and lines are the same as those of Case 1.

The plan with a 10% discount rate was obtained in Case 1. By decreasing the discount rate to 5%, it is expected that the candidate units with higher capital costs, i.e. units 1 to 6, become inferior. So, units 1 and 3 are not installed and installation of unit 5 is delayed by one year. However, Table XIV shows that cheaper units are installed in this case, in which the units 7 and 8 are installed at year 10 and units 9 and 10 are planned at year 9. In addition, similar to the 10% discount solution, there would be no need to install new

transmission lines when TS is applied and the discount rate is 5%. Accordingly, the investment cost and total planning cost are increased by 14.4% and 0.63%, respectively.

If we further decrease the discount rate and set it to zero, a quite different investment plan, as shown in last column of Table XIV, will be obtained. The discount rate of 0% means that there is no difference on the installation year of the candidate unit or line, since the investment cost will not change with time.

From the optimization viewpoint, all units are installed at the first year that they are required. Again using TS, there is no requirement for new transmission line investments, since TS satisfies the system feasibility. In comparison with the 10% discount rate, the investment cost and the total planning cost are increased by 47.8% and 1.36%, respectively when the discount rate is assumed to be zero.

TABLE XIV
CANDIDATE UNIT INSTALLATION YEAR FOR IEEE 118-BUS SYSTEM IN CASE 2

Candidate Unit	Discount Rate (%)		
	10	5	0
1	7	-	-
2	5	4	4
3	6	-	-
4	-	5	4
5	5	6	4
6	-	-	-
7	-	10	4
8	-	10	4
9	10	9	4
10	10	9	4
11	10	10	4
12	10	10	4
13	10	10	4
14	10	10	4
15	-	-	-
16	-	-	-

Case 3: In order to examine the impact of TS on the planning results more comprehensively, the expansion planning problem in Case 1 is solved for a variety of switchable lines. The number of switchable lines is varied here from 0 to 40, which 0 means that no line in the system has the switching capability, and 40 means that more than one fifth of transmission system is considered as switchable. Discount rate of 10% is considered for all cases.

The installation year of candidate units as a function of the number of switchable lines is shown in Table XV. The investment plan is a function of the number of switchable lines. However, no transmission line is installed when TS is applied. The investment cost is shown in Fig. 3. This figure shows that the investment cost is a function of the number of switchable lines. In the case of the no line switching capability, the investment cost includes the installation costs of units and lines; however, with the TS capability, the investment cost is only that of unit installations.

The operating cost of the system is shown in Fig. 4. By increasing the number of switchable lines from 0 to 30, the operating cost is decreased. However, the operating cost of the 40 switchable lines is higher than that of 30.

TABLE XV
CANDIDATE UNIT INSTALLATION YEAR FOR IEEE 118-BUS SYSTEM IN CASE 3

Candidate Unit	Number of Switchable Lines				
	0	10	20	30	40
1	-	7	5	5	7
2	5	5	7	7	5
3	7	6	6	6	-
4	5	-	-	-	6
5	6	5	5	5	5
6	-	-	-	-	-
7	-	-	-	-	-
8	10	-	-	-	-
9	9	10	10	10	10
10	10	10	10	10	10
11	-	10	10	10	10
12	10	10	-	10	-
13	10	10	10	10	-
14	10	10	10	10	10
15	-	-	-	-	-
16	-	-	-	-	-

Fig. 3 Investment cost in Case 3

Fig. 4 Operating cost in Case 3

Fig. 5 Total planning cost in Case 3

So, by increasing the number of switchable lines the operating cost of the system does not decrease monotonically.

The objective of the investment planning problem is to minimize the total planning cost, which is the sum of the investment and the operating costs. The total cost is depicted in Fig. 5. As expected, by increasing the number of switchable lines, the total cost is decreased uniformly. The reduction in the total planning cost for 10, 20, 30 and 40 switchable lines, as compared to the case with no switching, is 0.043%, 0.054%, 0.072% and 0.086%, respectively. These increments would amount to large savings in the case of large-scale power systems.

C. 1168-Bus System

As a large-scale power system, the 1168-bus system is used to compare the effectiveness of the proposed decomposition approach with that of the integrated model. This system has 149 units, 1474 branches, and 568 demand sides. 20 units are considered as candidate investments. The discount rate for candidate units is assumed to be 10%. The transmission flow limit is increased to alleviate the need for any transmission expansions. To obtain the solution in a reasonable time a planning horizon of three years is considered. 100 transmission lines are assumed to be switchable. The total planning costs as a function of execution time is depicted in Fig. 6. The solution of the integrated model is achieved using the CPLEX, where the total planning cost is the best current integer solution of the problem. In the decomposed model the total planning cost is the upper bound of the MIP planning problem, i.e. current solution of the decomposed problem.

As shown in Fig. 6, the integrated model finds a better solution initially, and is better than that of decomposed model for the next 14 hours. Also, it reaches a near optimal solution in just 3.5 hours. However, this near optimal solution cannot be improved further. On the other hand, the decomposed model would require an additional computation time but is able to reach a cheaper solution. After 15 hours, the solution of the decomposed model is 0.17% better than that of the integrated model. We continued with the execution of the two models for another 12 hours and learned that the solution of the integrated model did not change. However, the duality gap of the CPLEX solution continued to drop which is because of the increment in the best current node of the solution.

Fig. 6 Comparison of integrated and decomposed planning models

V. CONCLUSIONS

The TS application was investigated in the expansion planning of power systems. The expansion planning problem was decomposed into a master problem and two subproblems. The master problem found the optimal expansion plan by considering candidate units and lines. The subproblems utilized the proposed plan to satisfy the feasibility and check the possibility of optimal operation. The TS application for enhancing the system security and economics was considered in the subproblems while the role of TS for enhancing the expansion plan was taken into account in the master problem. The proposed approach was analyzed further through numerical examples introduced in the paper. The proposed TS approach can be utilized as an ISO model for coordinating the transmission expansion planning with the competitive generation capacity planning by representing an iterative process for representing the interactions among generation companies, transmission companies and the ISO, while considering the switching capability of lines.

APPENDIX

Suppose that we have the following conditional statement,

$$\text{If } v = 1 \text{ then } \sum_i a_i x_i = b, \quad (\text{A1})$$

where v is a binary variable, x_i is a continuous variable, and a_i and b are constant parameters. To model this statement in MIP format (A2) and (A3) are used.

$$\sum_i a_i x_i - b \leq M(1 - v) \quad (\text{A2})$$

$$\sum_i a_i x_i - b \geq m(1 - v) \quad (\text{A3})$$

Similarly, if we have the following conditional statement

$$\text{If } v = 0 \text{ then } \sum_i a_i x_i = b, \quad (\text{A4})$$

We can represent (A5) and (A6) in the MIP format,

$$\sum_i a_i x_i - b \leq Mv \quad (\text{A5})$$

$$\sum_i a_i x_i - b \geq mv \quad (\text{A6})$$

The constant values M and m are disjunctive parameters of the associated inequality constraint. Usually, M would not be less a specific value which is given as

$$M = \max \left\{ \sum_i a_i x_i - b \right\} \quad (\text{A7})$$

Similarly, m should not be larger than a specific value

$$m = \min \left\{ \sum_i a_i x_i - b \right\} \quad (\text{A8})$$

So, M and m are upper and lower bounds of the expression $\sum_i a_i x_i - b$, respectively.

These MIP representations of conditions can simply be extended to cases with more than one binary variable. The proposed formulations for line flows, considering the installation state and switching state as binary variables, are obtained similarly. So, disjunctive parameters of line flow constraints are

$$M_j^E = 2 PL_j^{\max, E} \quad (\text{A9})$$

$$m_j^E = -2 PL_j^{\max, E} \quad (\text{A10})$$

$$M_j^C = 2 PL_j^{\max, C} \quad (\text{A11})$$

$$m_j^C = -2 PL_j^{\max, C} \quad (\text{A12})$$

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Promoting the Investment on IPPs for Optimal Grid Planning

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Abstract—This paper presents a transmission expansion planning (TEP) model which coordinates investment decisions in monopolistic transmission and decentralized generator sectors. The proposed planning approach gauges transmission congestion and security constraints with respect to transmission investments while promoting investments on independent power producers (IPPs) through incentive payments. The paper includes discussions on incentive mechanisms and prioritization among qualified IPPs for several planning scenarios. Such incentives might be necessary to trigger investments on IPPs earlier than those projected by the decentralized generation system, when the power system security is threatened. The proposed planning approach would optimize the sum of transmission investments, incentive payments to IPPs, and congestion costs along the planning horizon. The case studies illustrate how the proposed planning algorithm could be utilized in order to determine incentive payments to candidate generators when necessary, and prioritize such incentives among multiple IPP candidates.

Index Terms - Transmission expansion planning, IPP investments, incentive payments, transmission security, transmission congestion.

NOMENCLATURE

b	Index for subperiod
d	Discount rate
i	Index for generator (existing and candidate)
k	Index for line (from bus m to bus n)
q	Single contingency index
t	Year index
CL	Number of candidate transmission lines
NCG	Number of candidate generators
NS	Number of subperiods
NT	Number of planning year
CI_{kt}	Capital investment cost of transmission line k in year t (\$/yr)
$R_{C,ibt}$	Forecasted energy sales price of candidate IPP i at subperiod b in year t (\$/MWh)
α_i	Profit coefficient of IPP i (%)
CI_{it}	Capital investment cost of IPP i in year t (\$/yr)
$P_{GC,ibt}$	Dispatched capacity of candidate generator i at subperiod b in year t (MW)
IP_{it}	Incentive payment required by IPP i in year t (\$/yr)

$OC_{GC,ibt}$	Operating costs of candidate IPP i at subperiod b in year t (\$/MWh)
AOC_{bt}	Additional operation cost due to congestion at subperiod b in year t (\$/yr)
X_{it}	Installation status of candidate generator of IPP i in year t , 1 if installed, otherwise 0
X_{kt}	Investment status of candidate line k in year t

I. INTRODUCTION

The liberalization and restructuring processes worldwide have introduced new complexities to the transmission expansion problem (TEP) [1]-[5]. This movement has introduced competition at the two extreme points of the industry infrastructure (i.e., generation and retailing) while keeping transmission and distribution sectors as natural monopolies. TEP is presented as a process which is decoupled from generation and distribution planning despite their natural and indispensable dependencies. This means that, in some ways, the transmission network will have to solicit users' involvement both at the generation and the demand sides which would introduce a new level of the TEP uncertainty.

This paper presents a new model for the coordination of TEP and decentralized generation investment planning. The model gauges the level of transmission congestion and security with respect to transmission investments while promoting generation investments through incentive payments to mitigate the operation risks when necessary. For the purpose of maintaining the system security such incentives which would trigger generation investments could be paid earlier than the IPPs' projected investment date.

The generation capacity market and the institution of capacity signals have been a controversial issue in the electricity industry restructuring. Many experts argue that the capacity mechanism is essential for encouraging the investment in the new capacity [6]. In theory, energy and ancillary services markets should provide incentives for such investments. However, most peaking units may not recover their fixed costs of investment without market price spikes. Thus, significant price volatilities may be necessary to make such investments feasible in the absence of capacity payments [7]. Given the political realities of electricity markets, prices may fluctuate insufficiently to induce investments when the available capacity is tightened; then an explicit capacity mechanism would be needed to signal capacity shortages and induce investments on generation [8].

The coordination between transmission and generation resource planning was addressed previously. Roh *et al* proposed a model that brings transmission and electricity

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market into the sphere of long-term generation resource planning [9]. Security payments to generation companies (GENCOs) by the ISO are proposed for supplying the load and satisfying the network security. The study shows that a proper expansion of transmission capacity could lower the ISO's security payment to GENCOs. Our planning approach considers this fact inherently by coordinating transmission and generation planning decisions. Botterud *et al* presented a stochastic dynamic generator investment model which offers a comprehensive treatment of long-term uncertainties and their influence on optimal generator investment decisions [10]. The proposed model assesses optimal investment strategies when the increase in demand, and thereby future prices, are uncertain. However, it considers only the generator investment decision and ignores its close linkage with transmission expansion. The interaction between transmission and generation in TEP was also investigated recently in [11]. The objective of TEP is to maximize the social welfare based on a valuation methodology outlined as proactive transmission network planning. It is assumed that network planner anticipates the way that generation investment and operations would react.

This study proposes an enhancement to the planning model given in [12] by considering incentive payments to IPPs to trigger generation investments when necessitated by the system security. The proposed coordinated planning model in [12] provides the best combination of transmission and generation investment planning, although there is no guarantee that profit-making IPPs will follow the proposed options which would maximize the social-welfare. Our approach is unique as it proposes an incentive mechanism to IPPs that considers this situation within a coordinated transmission planning problem.

Fig. 1 depicts the flowchart of the proposed method. The main distinction in this study is the integration of the IPP investment planning decisions with TEP when considering the system security in long-term planning studies. Thus generator investments which contribute to the optimal system planning (considering the network security) but might be delayed by IPPs for various reasons are considered in the proposed planning algorithm by including incentive mechanisms. For example, those IPPs which are essential for maintaining the system security during on-peak periods might require additional incentives due to the insufficient dispatch of their units during off-peak periods. We propose such an incentive mechanism within the context of coordinated planning performed by a central entity, which is assumed to be a state-owned transmission company. Accordingly, the planning concern as to whether profit-making IPPs will follow the coordinated planning option is taken into account in this paper.

The rest of the paper is organized as follows. The proposed planning model and the solution methodology are described in Section II which also presents the IPPs' investment problem and the interaction between the transmission company and IPPs during the planning process. Section III presents the case study of a two-bus system which enables easy understanding of the contribution of this paper, and application of the approach to modified IEEE 30 bus system. Prioritization among multiple

IPPs that qualified for incentive payment and determination of the incentive mechanism are also discussed in Section III. The conclusion drawn from the study is provided in Section IV.

Fig. 1. Integration of IPPs' investment planning decisions with TEP

II. PLANNING MODEL AND INCENTIVE MECHANISM

A. Centralized Transmission Expansion Planning Problem

The objective of the proposed planning problem is to optimize the transmission investment cost, the incentive payments to IPPs which contribute to the optimal solution, and the total additional operation cost due to congestion (AOCC), in the planning horizon while satisfying the system security based on the single contingency (i.e., N-1) criterion. The objective function is formulated as

$$\begin{aligned}
 Min \quad & \left\{ \sum_{t=1}^{NT} \sum_{k=1}^{CL} \left[\frac{CI_{kt} * X_{kt}}{(1+d)^{(t-1)}} \right] + \sum_{t=1}^{NT} \sum_{i=1}^{NCG} \frac{IP_{it} * X_{it}}{(1+d)^{(t-1)}} \right. \\
 & \left. + \sum_{t=1}^{NT} \sum_{b=1}^{NS} \frac{AOCC_{bt}}{(1+d)^{(t-1)}} \right\} \quad (1)
 \end{aligned}$$

where AOCC is the difference between generation dispatch costs when ignoring and considering transmission constraints along the planning horizon. The objective function is decomposed into security and operation problems and the DC power flow model [13] is utilized in the formulation of Benders cuts as illustrated in Fig. 1. Security cuts ensure the load curtailment criteria while meeting the N-1 contingency along the planning horizon. On the other hand, operation cuts force the planning algorithm to search for a better solution that would result in more economic dispatch solutions (i.e., minimize the AOCC). Thereby, transmission investment cost, congestion cost and incentive payments to the qualified IPPs are optimized iteratively. Here, the generator investment costs in the planning algorithm proposed in [12] are replaced by incentive payments to IPPs.

B. Decentralized Generator Investment Planning Problem

The main objective of a generation planning problem executed by IPPs (i.e., non-utility generators) is to maximize the profit based on investments. A generation investment project is profitable if the discounted project return is positive. The internal rate of return (IRR) is a popular concept for measuring the discounted project returns [14].

It is assumed here that there are no coupling constraints among IPPs for investment decisions. Accordingly, the investment planning problem of IPP for each generation candidate is to maximize the profit based on the corresponding investment along the planning horizon:

$$Max \left\{ \sum_{t=1}^{NT} \sum_{b=1}^{NS} \frac{DT_{bt}}{(1+d)^{(t-1)}} * \begin{pmatrix} R_{C,ibt} * P_{GC,ibt} \\ -OC_{GC,it} * P_{GC,ibt} \end{pmatrix} - \sum_{t=1}^{NT} \frac{CI_{it} * X_{it}}{(1+d)^{(t-1)}} \right\} \quad (2)$$

where $R_{C,ibt} = \alpha_i * OC_{GC,ibt}$ (3)

C. Incentive Requirement of IPPs

An investment decision for a specific IPP depends on its forecasted profit, which is a function of expected energy production (2). For a fixed energy sale price, R_C , the expected profit depends solely on the energy production. If an IPP could forecast the level of energy sales (i.e., dispatch level) for a predefined level of energy sale price, then its investment decision would be as simple as calculating the IRR based on procurements. Therefore, the expected dispatch level is a critical component of a candidate's investment decision which gives an important signal to the IPPs on their forecasted energy price. The IPP would presumably make no investments unless its deficiency is compensated. Essentially, the correct time for making any investment is when the discounted project return is positive. Accordingly, the minimum incentive payment required by candidate i in year t is assumed to be the difference between the annual investment and the expected profit from energy sales stated as

$$IP_{it} = \frac{CI_{it} * X_{it}}{(1+d)^{(t-1)}} - \sum_{b=1}^{NS} \frac{DT_{bt}}{(1+d)^{(t-1)}} * \begin{pmatrix} R_{C,ibt} * P_{GC,ibt} \\ -OC_{GC,it} * P_{GC,ibt} \end{pmatrix} \quad (4)$$

When (4) is negative, the investments are profitable, the required incentive is assumed to be zero, and the IPP's investment could manipulate the mechanism.

The proposed incentive mechanism may encourage IPPs to game the market by manipulating the incentives and requiring additional payments. However, the additional incentives will be rejected by the proposed algorithm if an alternative option is available. Such alternatives may include either transmission enforcements or the selection of another IPP with more reasonable incentive requirements. The selection of more economical alternatives among candidates is made possible by Benders cuts. On the other hand, when alternative candidates are not available (due to locational importance), an IPP whose commitment is critical to the system security may essentially abuse the situation. That is, security cuts generated during the iterative planning process may force such investments regardless of their costs (i.e., incentive requirements). The

proposed planning model can be utilized by the authorities to identify such opportunities by applying sensitivity analyses and investigating the impact of energy prices on planning alternatives.

D. Interaction between Transmission Company and IPPs

In the proposed approach, each IPP provides the energy sale price of the corresponding generation investment to the ISO. The ISO calculates the expected economic dispatch along the planning horizon. Accordingly, each IPP determines its annual incentive requirements for investments. These incentive requirements are utilized as payments in determining the operation cuts which are iteratively included as constraints of the objective problem (1). The interaction between the transmission company and IPPs which is managed by the ISO is illustrated in Fig. 2. Fig. 1 shows a more detailed information exchange which continues until an optimal planning solution is found.

Fig. 2. Information exchange between the transmission company and IPPs

III. CASE STUDIES

The case studies include a two-bus system and the IEEE 30-bus system as discussed below.

A. Two-bus system

The two-bus system depicted in Fig. 3 shows two generators that can supply the loads at two different buses. It is assumed that G1, which is located at a distance from the large load at Bus 2, is cheaper than G2 (i.e., closer unit). The solid lines correspond to existing transmission lines and the dashed lines correspond to the transmission reinforcement. The dashed generator at Bus 2 corresponds to a candidate investment by an IPP. The annual load growth rate is 5% at Bus 1 and 8% at Bus 2. The transmission investment cost is 800 \$/MW-mile. A 5% annual interest rate based on a 10-year loan is utilized to calculate the annual capital investment for transmission line and generator.

Fig. 3. Two-bus system

The generation investment data are given in Table 1.

Provided that the candidate generator is operated at full capacity (i.e., $8,760 \times 200 = 1,752$ GWh per year), the discounted annual profit based on its investment is approximately 2 \$M/year. The profit will decrease along the planning horizon if the unit is operated at less than the full capacity.

TABLE 1
TWO-BUS SYSTEM CANDIDATE GENERATOR DATA (G_i)

Capacity (MW)	Capital investment cost (\$M/MW)	Forecasted energy sale price (\$/MWh)	Profit in energy sales (%)
200	0.75	20	60

The following cases are studied for the two-bus system:

Case 1 – Without Promoting IPP Investment

The TEP problem is solved without considering the candidate generator. According to the given demand forecasts, the total demand to be supplied in two buses will be approximately 1,025 MW in year 10. The existing generators could not supply this demand unless the transmission line enforcement would take place. The planning problem in this case will only determine the optimal timing for transmission investment. The TEP results are given in Table 2. The transmission enforcement will take place in year 7 despite the congestion in year 6. It is obvious as the \$6.09M AOCC in year 6 is smaller than the annual transmission investment (i.e., \$6.11M). On the other hand, given the high annual peak demand increase, the AOCC would be \$14.9M unless the transmission investment would take place in year 7. The 25 MW of total demand is supplied by the expensive generator G2 in year 10 since G1 is already fully loaded. According to the definition, the total AOCC is zero in year 10.

Case 2 - Promoting the IPP Investment

The candidate generator investment at Bus 2 is considered. Table 3 shows that the transmission line enforcement is deferred by 4 years provided that the candidate generation investment is procured in year 7. Although the candidate generator is fully loaded in year 10, the transmission investment mitigates the possible congestion by enabling the dispatch of cheaper generator G1. The \$6.09M AOCC is again due to the congestion in year 6 as in Case 1. The annual incentives to trigger generation investments are given in Table 4. Since no generation dispatch is required in years 1-6, the incentive requirement is the same as the annual capital cost of the generator. The incentives provided in years 7 and 8 would compensate the IPP's deficit which is due to low dispatch. Note that even though the energy sale prices of the existing generator G1 and candidate generator G_i are the same, the dispatch priority is given to G1. It is assumed that the existing generator G1 already has long-term contracts and therefore deserves the priority, which is a reasonable assumption.

TABLE 2
TWO-BUS SYSTEM - CASE 1 RESULTS

Transmission investment	TTIC* (\$M)	AOCC (\$M)	TC** (\$M)
Year 7	24.44	6.09	30.53

* TTIC: Total transmission investment cost

** TC: Total cost along the planning horizon

TABLE 3
TWO-BUS SYSTEM CASE 2 RESULTS

Transmission investment year	Generator investment year	TTIC (\$M)	TIP* (\$M)	AOCC (\$M)	TC (\$M)
10	7	6.11	14.44	6.09	26.64

* TIP: Total incentive payment to the IPP

TABLE 4
TWO-BUS SYSTEM CASE 2 INCENTIVE PAYMENTS

Year	1-6	7	8	9	10
Dispatch (MW)	0	85.53	140.37	199.6	200
Incentive payment (\$M)	19.1	10.1	4.34	0	0
Investment status of G _i *	0	1	1	1	1

* If installed: 1, otherwise: 0

This example shows the effectiveness of promoting the generation investments in the optimal TEP. The incentive payments are required to trigger generation investments earlier than envisaged by IPPs. When there are multiple candidate generators, those which contribute significantly to the system security and optimal operation are given the priority. The security and operational cuts in the proposed planning approach satisfy this criterion when considering the marginal effects of generation investments on the system security and optimal operation.

Table 5 compares the results of Cases 1 and 2 from the consumers' viewpoint in which Case 2 provides a more economic solution. The difference in the total cost between the two cases is \$3.89M from the transmission company's viewpoint (see Tables 2 and 3) and \$8.52M from the consumers' viewpoint (see Table 5).

TABLE 5
TWO-BUS SYSTEM - CONSUMER POINT OF VIEW

Case	TIRC* (\$M)	TEC** (\$M)	TC (\$M)
1	24.44	1426.14	1450.58
2	20.55	1421.51	1442.06

* TIRC: Total investment related cost (TTIC + TIP)

** TEC: Total energy cost

In Case 1, the dispatch of expensive generator G2 is inevitable in the last year as G1 is fully dispatched and there is no other supplier available. Although the AOCC by definition is zero in year 10, the operation of G2 increases the cost to consumers by \$8.52M - \$3.89M = \$4.63M. Consequently, the utilization of AOCC approach provides the optimal planning solution while assessing the annual investment/profit against congestion cost.

One of the transmission planner's main concerns in promoting multiple market players is the inability to institute a fair incentive mechanism in the market. In the example, G2 at Bus 2 might consider that the incentives will provide unfair advantages to G_i when contributing to the transmission system security. Indeed, both G2 and G_i have the same marginal effects on security, although G_i contributes to the economic dispatch additionally. On the other hand, if G2 benefits from the promotion as well, then the cost of planning may not be optimal.

The G_i in Case 2 deserves an incentive due to its contribution to the system security and optimal operation. Before proposing an incentive plan, it is better to analyze the two-bus example further. Table 4 shows that the additional cost of energy due to the incentive payment in year 7 is 13.48 \$/MWh (i.e., \$10.1M/85.53MW/8760h). Accordingly, the

breakpoint energy sale price for the IPP's investment on Gi in year 7 is 33.48 \$/MWh (i.e., 20 + 13.48). In order to be fair, a tender could be opened in the initial year to buy 85.53 MW x 8760h $\approx$ 750GWh energy at 33.48 \$/MWh in year 7 and 140.37MW x 8760 h $\approx$ 1230GWh at 23.53 \$/MWh in year 8. If the existing generator G2 signs a contract to sell energy at those predefined prices, then there would be no need to promote the investment. It should be noted that this amount of advance energy purchase agreement with G2 will delay the transmission enforcement by 2 years unless the investment of G2 takes place in year 9. On the other hand, the IPP is expected to make the investment. Otherwise G2 will hold its market power unless the transmission enforcement would take place.

Given the feasibility of investing on Gi in year 7 with additional incentives, the existing generator G2 is clearly competitive as its energy sale price (40 \$/MWh) is higher than that of Gi even after paying the incentive (i.e., 33.48 \$/MWh). So our approach not only ensures the system security but also enables the appraisal at expected energy sale prices. Thereby, the regulatory authority would have additional ideas on the competition level and market power.

This simple example illustrates how the candidate investments, which contribute to the planning problem (1) at most, are successfully selected by the proposed planning methodology. In a specific case when several IPPs are willing to invest in a same bus, the operation cut considers the incentive payments to all candidate generators as well as investment cost of transmission lines and AOCC. This is essential as the candidate generators willing to connect to the same bus will have the same incremental contribution to the security (i.e., load curtailment). Note that, the candidate generator Gi in the simple 2-Bus example deserves an incentive payment despite that G2 is connected to the same bus. The reason is that the contribution of Gi to reducing the AOCC is higher than its incentive requirement along the planning horizon. The next example illustrates the performance of the proposed approach when there is more than one candidate generator considered for investment.

B. IEEE 30-Bus system

The proposed planning approach is applied to the modified IEEE 30-bus system, depicted in Fig. 4, to analyze the performance of the proposed approach when there are several candidate generators. The existing transmission grid satisfies the single contingency security criterion at the initial year. The possible transmission enforcements are shown in Fig. 4. The initial set of candidate transmission lines are determined based on preliminary load flow analyses. The lines which are loaded more than 50% in the initial year are selected as candidates for investment. The initial grid consists of 50 transmission lines, 15 candidate transmission lines, 21 demand buses, 7 existing power plants and 8 candidate generators. The length of each transmission line (in miles) is indicated in Fig. 4. Buses with relatively higher load densities are indicated by bold arrows. The modified IEEE 30-bus system data which include transmission lines, generators, and forecasted load are given in http://motor.ece.iit.edu/Data/IEEE_30bus_modified.xls. It is

assumed for simplicity that the construction time for each transmission lines or generator is one year.

Fig. 4 . Modified IEEE 30-bus System

TABLE 6
IEEE-30 BUS SYSTEM CANDIDATE GENERATOR TYPES

Type ⁽¹⁾	Capacity (MW)	Capital investment cost (\$/MW)	Loan schedule	ESP ⁽²⁾ (\$/MWh)	Profit ⁽³⁾ (%)
H	300 or 100	1	20 years	18	70
T	(see the	0.6		20	40
C	Case studies)	0.5	7%	22	30

⁽¹⁾ H: Hydro plant; T: Coal fired thermal plant; C: Natural gas combined cycle plant. ⁽²⁾ ESP: Energy sale price. ⁽³⁾ Profit based on energy sale price

The candidate investment pool includes 3 types of generators as illustrated in Table 6. For simplicity, generator capacities are all assumed to be same. In this table, the capital investment on hydro generators is the highest. The hydro energy sale price is the lowest which provides the highest profit among the candidate generators for the given energy sale price. It is assumed that all candidate generators provide the same annual profit when operating in full capacity.

Buses with higher load distribution factors (bold arrows in Fig. 4) are connected in metropolitan regions so that capital investments for enforcing transmission lines in those regions would be higher than the others. Such regions are indicated by "M" (representing Metropolitan) in Fig. 4.

A planning year is divided into 4 subperiods representing seasonal load patterns. We consider the following four cases to analyze the performance of the proposed planning model. The planning horizon is assumed to be 10 years in all scenarios. The results are summarized in Table 7.

Case 1 – Without Promoting IPP Investment

The annual peak demand increase is 2% in all seasons along the planning horizon. In this case the existing generators are

sufficient to supply the forecasted demand. Given the low demand increase ratio, the planning model does not provide any incentives to IPPs. Transmission investments shown in Table 7 are already sufficient to satisfy the security criterion while minimizing the investment cost and the transmission congestion level along the planning horizon. In other words, incentive payments required by IPPs are considerably high as compared to transmission investments.

TABLE 7
30-BUS SYSTEM RESULTS SUMMARY

Case	API *	Investment **	TTIC (\$M)	TIP (\$M)	AOCC (\$M)	TC (\$M)
1	2%	L ₉₋₁₀ ; Y ₁ L ₅₋₇ ; Y ₂ L ₉₋₁₁ ; Y ₃	31.19	-	24.64	55.83
2	2%	L ₉₋₁₀ ; Y ₄ L ₅₋₇ ; Y ₅ L ₉₋₁₁ ; Y ₆ G _{H,16} ; Y ₁	20.45	≈ 5	21.40	46.85
3	5%	L ₅₋₆ ; Y ₁ L ₅₋₇ ; Y ₁ L ₉₋₁₀ ; Y ₆ L ₉₋₁₁ ; Y ₉ L ₁₂₋₁₆ ; Y ₁₀ L ₁₅₋₂₃ ; Y ₁₀ G _{H,16} ; Y ₂ G _{H,20} ; Y ₇	53.65	40.56	≈ 0	94.21
4	7%	L ₅₋₆ ; Y ₁ L ₅₋₇ ; Y ₁ L ₉₋₁₀ ; Y ₈ L ₉₋₁₁ ; Y ₇ G _{T,26} ; Y ₇ G _{T,23} ; Y ₁₀ G _{H,16} ; Y ₅ G _{H,20} ; Y ₂	51.52	100.85	≈ 0	152.37

* API: Annual peak demand increase (%)

** L_{i,j}: Investment on Transmission line from bus *i* to bus *j*; Y_i: Year *i*; G_{X,i}: Candidate generator at bus *i* (X: generator type index)

Case 2 - Promoting IPP Investment (Providing a more Economical Solution)

In Table 6, the capacity of candidate generators is reduced from 300 MW to 100 MW so that the annual incentives are comparable with transmission investments. The other financial figures are fixed in Table 6. The planning result in Table 7 shows that the investment on hydro generator at Bus 16 (i.e., G_{H,16}) in year 1 defers the transmission investment proposed in Case 1 while satisfying the security criterion with a reduced AOCC along the horizon.

The proposed dispatch for G_{H,16} along the horizon and corresponding annual incentives are given in Table 8. The generator is fully dispatched during peak demand seasons (i.e., S₂ and S₄) in each year which is not the case during the off-peak seasons. For the same energy sale price, the dispatch priority is given to existing generators considering their possible long-term contracts. Consequently, the incentive in initial years is due to the partial operation of G_{H,16} during the off-peak seasons. An energy purchase agreement could be made in advance with the corresponding IPP to trigger the investment on G_{H,16} in year 1. Table 8 shows the financial attributes of such agreements when considering the proposed method.

TABLE 8

30-BUS SYSTEM CASE 2 : DISPATCH AND INCENTIVE PAYMENTS FOR G_{H,16}

Years		Y ₁ [*]	Y ₂	Y ₃	Y ₄	Y ₅	Y ₆	Y ₇	Y ₈	Y ₉₋₁₀
Dispatch (MW)	S ₁ ^{**}	0	0	0	67	89	79	89	99	100
	S ₂	100	100	100	100	100	100	100	100	100
	S ₃	30	100	100	100	100	100	100	100	100
	S ₄	100	100	100	100	100	100	100	100	100
Incentive (\$M)		2.95	1.03	1.03	0	0	0	0	0	0
Advance contracts	\$/MWh	24	19	19	0	0	0	0	0	0
	GWh	500	650	650	0	0	0	0	0	0

* Y_i: Year along the planning horizon

** S_i: Season in a year

Case 3 & 4 - Promoting the IPP Investment (Supply / Demand Adequacy)

The annual peak demand increase is assumed to be 5% in Case 3 so the total capacity of existing generators would not be sufficient to supply the forecasted demand along the planning horizon. Contrary to the previous cases, the generation investment is inevitable for satisfying the system security criterion. Assuming that the capacity of all candidate generators is again 300 MW, our planning model proposes a combination of transmission and generation investments shown in Table 7, which optimizes the TEP problem. Given their lowest energy sale prices, the hydro generators are given the priority not only for security concerns but also minimizing the congestion along the planning horizon. Indeed, the expected AOCC is zero under the proposed investments, as shown in Table 7.

The higher energy sale prices would promote investments on other types of candidate generators only if such investments contribute to the system security. In Case 4, the 7% annual peak demand increase would promote investments on thermal generators at buses 23 and 26 in addition to hydro generators to compensate for supply deficiency. Table 7 shows the optimal investments and corresponding total costs along the planning horizon.

Further Discussions on the IEEE 30-Bus System

The IEEE modified 30-Bus system example shows how incentives are prioritized among candidate generators to satisfy the system security and optimize TEP. The optimal investment which satisfies the system security criterion could also mitigate the transmission congestion along the planning horizon (Cases 3 and 4). On the other hand, when the installed capacity is sufficient, the investment on candidate generators would be promoted only if the incentives are comparable with transmission investments (Cases 1 and 2).

In the case of a single generator investment, bilateral energy purchase contracts are the obvious incentive mechanism as proposed in Case 2. Incentive payments are essentially based on the proposed energy sale prices of the corresponding IPPs. On the other hand, a tender could be opened in the case of multiple generators. The existing peaking generators in a region would contribute to the security and should be considered equally.

As shown in Cases 3 and 4, the incentive mechanism is more challenging when the candidate generators are at different regions and/or deserve incentive in different years. In

Case 3 (with a 5% annual demand increase), both $G_{H,16}$ and $G_{H,20}$ contribute to the supply deficiency problem, although $G_{H,16}$ is promoted just two years after the initial year. In Case 4 (with a 7% annual demand increase), $G_{H,20}$ is promoted from the second year on. In Case 4, two more generators ($G_{T,23}$ and $G_{T,26}$) are proposed during the second half of the planning horizon. A tender may be opened based on the following considerations:

- The difference in the annual demand increase is just 2% between Cases 3 and 4. Therefore, the incentive mechanism should consider the Case 4 which is the worse Case in the sense of security concern.
- $G_{H,16}$ and $G_{H,20}$ should be considered equally given that they are in the same region (i.e., equal marginal contribution to security) and their energy sale price - and accordingly incentive requirements - are equal under the same dispatch.
- The incentive payment to $G_{T,23}$ and $G_{T,26}$ could be postponed since it is proposed after the seventh year (see Table 7, Case 4). That is, the incentive payment to the designated IPPs could be decided later. The load growth uncertainty along the planning horizon also supports this idea.

Consequently, the tender could be opened to sign contracts with IPPs of $G_{H,16}$ and $G_{H,20}$ for an investment in year 2. Table 9 shows the financial aspects of such a tender. Note that the average energy purchase price is 20.5 \$/MWh which is higher than the 18 \$/MWh energy sale price envisaged by the IPPs to compensate the early investment. Furthermore,

- The 20.5 \$/MWh average energy price in Table 9 ensures the required IPPs incentive for the 280 MW operation in 7 years. The IPP could also participate in the ancillary service market and/or fulfill its reserve requirement by the remaining 20 MW capacity in Cases 3 and 4.
- Averaging the incentive mechanism to 7 years is due to the fact that no additional investment is made by the market forces. Meanwhile, it will be necessary to open a second tender to ensure the security of the system under the worse annual load growth scenario.
- If both IPPs intend to make the contract shown in Table 9, an auction could be considered and the IPP which accepts the lower energy purchase price would take the higher risk.

TABLE 9
FINANCIAL ASPECTS OF THE PROPOSED TENDER BETWEEN $G_{H,16}$ AND $G_{H,20}$

Incentive duration (years)		7
Total incentive along the planning horizon (\$M)		43.5
Advance contract	MW	280
	TWh/year	2.25
	\$/MWh	20.5

IV. CONCLUSIONS AND REMARKS

In this paper, a multi-year TEP model is proposed which possible incentive payments to IPPs to trigger candidate generation investments. The purpose is to get an optimal planning solution when considering the system security and congestion along the planning horizon after the restructuring of power systems. The proposed approach would successfully to optimize the sum of investment cost of transmission lines,

incentive payments to IPPs, and forecasted operation costs due to congestion along the planning horizon. The results of numerical examples (two-bus and the IEEE 30-bus systems) show the effectiveness of the proposed model.

The necessity of incentives to trigger IPP investments was evaluated within the TEP problem concerning the security and the congestion of grid along the planning horizon. The main idea is to trigger investments on IPPs earlier than those projected by the decentralized generation system, when the power system security is threatened. The case studies illustrate how the proposed planning algorithm could be utilized in order to determine incentive payments to candidate generators when necessary, and prioritize such incentives among multiple IPP candidates. The proposed planning model is applicable to restructured power systems, particularly during the market development phase when inherent uncertainties in existing policies and electricity prices due to the considerable share of state-owned generation companies could signal delays in investment decisions by IPPs.

The incentive offers to IPPs for advancing their generator investment plan is conceivable particularly when such investments are subject to low dispatch levels during initial years. For instance, peaking generators could contribute to the grid reliability, particularly during on-peak periods. Although they are expensive, system operators would appreciate the availability and the commitment of such units in emergency conditions. A considerable share of consumers would also prefer to pay extra instead of facing any interruptions. Accordingly, the following incentive mechanism could be proposed: either make a direct energy purchase contract with IPPs or open a tender among IPPs when fairness is a concern. Both incentive mechanisms should take into account the fact that incentive payments proposed by our planning algorithm depend on the energy sale prices provided by IPPs, as illustrated in Table 8.

The proposed planning algorithm would be utilized by an independent authority that is responsible for the long-term security of the power system. Such an institution is assumed to be a state-owned transmission company in this paper, which is indeed common in most EU countries. The IPP decisions would be reviewed and regulated by the authority as an independent entity. Accordingly, the authority is responsible for both determining and offering the incentives or making direct energy purchase contracts with the qualified IPPs. The planning uncertainties including energy sale prices and the role of monopolistic state-owned transmission company are among IPPs' risk factors that could result in delays on generation investment decisions.

Given their contribution to both power system security and transmission investment cost reduction (not only by postponing the transmission investment but also by ensuring the optimum transmission/generation expansion planning), such incentive payments to IPPs should be recovered from consumer payments. Accordingly, the incentive payments could be considered as a parameter in calculating the transmission usage charge by consumers. They could also be considered as capacity payments by consumers, like the ancillary services payments which are also related to the system security. The distribution of incentive payments among

the consumers is beyond the scope of this paper, and will be discussed in detail in a future study.

Although the proposed incentive mechanism may encourage IPPs to game the market by manipulating the incentive requirements, those payments will be rejected in the proposed algorithm by means of Benders cuts if better alternatives (transmission lines or IPPs) could be identified. On the other hand, the proposed planning model could be utilized to reveal market manipulations and measure the level of market competition, as illustrated in Section 2 (Two-Bus system, Case 2). Such issues should indeed be among the regulatory authority's main concerns when considering the system security. When the manipulation of incentives is a concern, the authority could make additional sensitivity analyses to evaluate the impact of energy price on the planning solution.

The numerical examples also illustrated how the risk of generator investments - due to low dispatch levels during initial years of the investment - could signal delays in IPP investments. The risk is demonstrated by providing IPPs the expected dispatch levels of the investments based on their envisaged energy sale prices. This indicator would essentially provide IPPs with important signals on their forecasted energy price and cover investment uncertainties considerably.

A future study could consider the impact of electricity price forecast uncertainties in electricity markets. The planning algorithm could be improved by considering the demand side management and load curtailment costs. In addition, generator planning criteria could be improved further by considering more sophisticated financial models. The net present value (NPV) approach considered in this paper would ensure a profit; however, it does not consider investment opportunities. The NPV could be positive while there is no optimal time for investment as there might be a chance to get larger NPVs by delaying the proposed investments.

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BIOGRAPHIES

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A Hybrid Model for Day-Ahead Price Forecasting

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Abstract—This paper presents a hybrid time-series and adaptive wavelet neural network (AWNN) model for the day-ahead electricity market clearing price forecast. Instead of using price series, one-period continuously compounded return series is used to achieve more attractive statistical properties. The autoregressive moving average with exogenous variables (ARMAX) model is used to catch the linear relationship between price return series and explanatory variable load series, the generalized autoregressive conditional heteroscedastic (GARCH) model is used to unveil the heteroscedastic character of residuals, and AWNN is used to present the nonlinear, nonstationary impact of load series on electricity prices. The Monte Carlo method is adopted to generate more evenly distributed random numbers used for time series and AWNN models to accelerate the convergence. Several criteria such as average mean absolute percentage error (AMAPE) and the variance of forecast errors are used to assess the model and measure the forecasting accuracy. Illustrative price forecasting examples of the PJM market are presented to show the efficiency of the proposed method.

Index Terms—AMAPE, ARMAX, AWNN, day-ahead price forecast, GARCH, Monte Carlo, time series method, variance of forecast errors.

NOMENCLATURE

Variables:

a_t	Noise process.
a_{ij}, b_{ij}	Translation and dilation parameters of wavelets.
c	Constant item in the GARCH model.
d	Differential order.
e	Bias of the output node in AWNN.
h_t	Conditional variance of residual series at time t .
i, j	Index.
k	AWNN training iteration index.
m	Number of input layer of AWNN.
MSE_T^k	Mean squared error (MSE) on testing set at iteration k for AWNN.
MSE_V^k	MSE on validation set at iteration k for AWNN.

$\overline{MSE}_V^k$	Average MSE on validation set until iteration k for AWNN.
n	Number of hidden nodes of AWNN.
O_t	Forecast electricity price at time t .
p, b, q	Orders of time series models.
W_i, W_j, W_{ij}	Weights of AWNN.
$\overline{R(d)}$	Average value of $R_t(d)$ series.
t, τ	Index of time series.
α_i, β_i	GARCH coefficients.
$\phi(B)$	Coefficient function for price series.
$\varphi(B)$	Coefficient function for load series.
$\theta(B)$	Coefficient function for noise process.
ρ_k	Sample autocorrelation value of lag k .
ε_t	Residual at time t .
γ^k	Generalization factor of iteration k for AWNN.
$\overline{\gamma}^k$	Average generalization factor until iteration k for AWNN.
σ_E^2	Variance of forecast errors.
σ_V^k	Standard deviation (STD) of MSE on validation set until iteration k for AWNN.
σ_γ^k	STD of generalization factor until iteration k for AWNN.

Constants:

B	Backshift operator, means $B^p \cdot P_t = P(t-p)$.
$F^{-1}(\cdot)$	Inverse probability distribution function.
L_t	Load at time t .
P_t	Electricity price at time t .
R_t	One-period log return at time t .
$R_t(\tau)$	Log return of τ -period at time t .
T	Study period.

I. INTRODUCTION

WITH the introduction of restructuring to the electric power industry, the price of electricity is becoming the focus of all activities in electricity markets. Price forecasting

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techniques are used for bidding purposes and hedging against volatilities. With a good next-day market clearing price forecast, a market participant would be able to delineate better financial decisions. That is, a power producer can develop appropriate strategies to maximize its payoff and a consumer can minimize its utilization cost [1].

Electricity has distinct characteristics as compared to other commodities; it cannot be stored economically and transmission congestion may prevent a free exchange of power among control areas. Thus, electricity price series can exhibit a major volatility and the application of forecasting methods prevailed in other commodities can pose large errors in electricity price forecasting. For different applications, price forecasting can be categorized into very short-term (several minutes to few hours), short-term (few days), midterm (few months) and long-term (few years). In this paper, we focus on the day-ahead market clearing price forecasting in electricity markets. A reasonable forecasting algorithm could capture important properties of electricity prices such as spikes, mean reversion, seasonality, and fat tails.

There are several possible methods for the day-ahead electricity price forecasting. The first approach is based on fundamental models, which is to simulate the exact physical model of power system components and apply algorithms which consider physical characteristics of power networks. Such an approach would express electricity prices based on marginal generation costs with the consideration of transmission congestion, losses, and other ancillary service requests in power markets [1], [2]. Fundamental models account for the impact of physical capacity of power plants and transmission lines, and demand characteristics and fluctuations. The most difficult issue here is that a fundamental model may require significant amounts of real-time data on power systems which can result in a complex computation process.

The second approach is based on mathematical finance models which were originally developed and widely used for stock and interest rate markets. Skantze *et al.* [3] developed a dynamic model to describe price series based on interactions of supply bids and load demands, which are simulated as mean reverting processes and exponential functions, respectively. The market clearing price was calculated as the cross section of aggregated supply and demand bid curves. A diffusion model for electricity prices, based on stochastic models for supply and demand curves, was proposed by Barlow [4] to exhibit price spikes. By fitting to historical data with the maximum likelihood estimation, Barlow concluded that the proposed diffusion model could provide a better fit than models with jumps. The finance models reflect the electricity price volatility caused by supply and demand, thus are suitable for option valuation and risk assessment purposes. The drawback is that it is very difficult to incorporate physical characteristics of power systems, such as transmission congestions, network losses, and contingencies, into mathematical finance models which may cause a discrepancy between the finance model solution and the real-time status of power systems.

The third approach is based on game theory models, which are particularly focused on the impact of bidders' strategic behavior on electricity prices. Bolle [5] used supply and de-

mand functions as instruments to determine market equilibria. It showed that under a certain condition, an equilibrium exists for every finite spread of autonomous demand, including small, nonstrategically acting consumers. Lower bounds of market prices were also computed. Ruibal *et al.* [32] used three oligopoly models, Bertrand, Cournot, and supply function equilibrium, to obtain closed form expressions for expected values and variances of hourly electricity prices as well as average prices, with the consideration of hourly demand volatility and random outages of generating units. It concluded that the introduction of competition may decrease expected prices but variances may actually increase. Li *et al.* [6] used the incomplete information game theory to analyze competitions among transmission-constrained GENCOs. Based on the solution of incomplete information game, the Bayesian Nash equilibrium which represents locational marginal prices (LMPs) was calculated using the ISO's security-constrained economic dispatch (i.e., a market clearing model). The problem was an iterative bilevel process, with the upper process representing individual GENCOs' bidding strategies to maximize payoffs and the lower process solving the ISO's market clearing problem for calculating LMPs. One presumption in the game theory is that all players are rational, which is not always the case in electricity markets. Other drawbacks are represented by time-consuming processes for calculating Nash equilibria.

The fourth method is based on regression models, which include time-series, and artificial intelligence models such as artificial neural network (ANN) and fuzzy logic. Regression models relate electricity price fluctuations to historical prices and other explanatory factors such as temperature, time of day, load demand, etc. The autoregressive integrated moving average (ARIMA) time series was applied to load forecasting [7], [8]. Contreras *et al.* [9] proposed an ARIMA model for the day-ahead electricity price forecasting, with examples from the Spanish electricity market and the PJM electricity market. Backshift factors were introduced into the ARIMA model for reflecting the seasonality of prices. In addition, it reported that the inclusion of explanatory variables, such as demand and available daily production of hydro units, may improve price forecasts with large spikes. Conejo *et al.* [10] proposed a hybrid wavelet transform and ARIMA model to forecast day-ahead electricity prices. Wavelet transform was used to decompose historically ill-behaved price series into a set of well-behaved constitutive series. Then, ARIMA was adopted for each constitutive series and the inverse wavelet transform was used to reconstruct a better forecast result. Gao *et al.* [11] used a three-layer back propagation network to forecast day-ahead market clearing prices (MCPs) and market clearing quantities (MCQs). Historical MCPs and MCQs, system loads, fuel prices, power exchanges, weather, and season indices that influenced market prices were used for network training, validating, and forecasting. Holiday data were pretreated as weighted average of following normal days. Price spikes were truncated for a better accuracy of normal prices. Mandal *et al.* [31] explored an ANN model based on similar days method to forecast day-ahead electricity prices in the PJM market. The impact factors were historical loads and price series of the days similar to those of the forecast day. Pindoriya *et al.* [33]

proposed an adaptive wavelet-ANN by using the Mexican hat wavelet as the activation function for hidden-layer neurons of feed-forward ANN. The forecast results showed good accuracy compared to ARIMA, multi-layer perceptrons, radial basis functions, and fuzzy neural networks. Swanson *et al.* [29] compared various adaptive and nonadaptive, linear and potentially nonlinear models, and concluded that the hybrid models, by grouping the multivariate adaptive linear and nonlinear models, dominate other models and provide least confused forecasts. The regression method is simple and computationally efficient. It requires detailed and correct historical data and proper model (orders of time series model, details of layer structure of artificial intelligence model) for adaptation and forecasting.

Price spikes were addressed regularly in electricity price forecasting. Previously proposed models preprocess, ignore, or truncate price spikes in order to get better forecasts for hourly electricity prices. Zhao *et al.* [30] developed a data mining based approach to forecast price spikes. Feature selection techniques were described to identify attributes relevant to the occurrence of spikes, including system demand, system supply, seasonality, scheduled interchanges, and dispatchable loads. Two algorithms, i.e., support vector machine and probability classifier, were applied as spike occurrence predictors. Guan *et al.* [12] proposed that price spikes might be the result of power suppliers' strategic gaming behavior. A prisoner's dilemma matrix game was formulated, and the notion of opportunistic tacit collusion was introduced to explain strategic bidding behaviors in which suppliers withhold a generation capacity from the market to drive prices up.

This paper focuses on day-ahead electricity market clearing price forecasts with large volatilities. Return series is used instead of original price series to capture statistical properties. The ARMAX model is used to seize the linear relationship between price return series and load series, the GARCH model is used to present heteroscedastic characteristics of residuals, and AWNN is used to show nonlinear and nonstationary impacts of system loads on electricity prices. Our proposed hybrid model provides a 24-h MCP forecast of the next day based on historical data and forecast explanatory factors. To illustrate our model, price forecasts in the PJM electricity market [13] are calculated and discussed.

The rest of the paper is organized as follows. Section II describes the proposed model and its solution methodology. Section III presents illustrative examples to show the proposed model applied to the PJM electricity market. Conclusions are provided in Section IV.

II. FORECASTING METHODOLOGIES

In competitive power markets, electricity prices appear to be highly volatile with nonstationary means and variances. The prices correspond to seasonality, weekdays, weekends, and holidays. Furthermore, power system loads as an explanatory factor would impact electricity prices. Here, we propose a hybrid model that uses ARMAX time series to forecast linear relationships between electricity price return series and system load series, followed by GARCH to simulate nonconstant variances of residuals, and applies AWNN to forecast nonlinear

Fig. 1. Flowchart of the proposed forecasting procedure.

and nonstationary impacts of system loads on electricity prices as shown in Fig. 1. In Fig. 1, the ARMAX model is first applied for forecast using historical prices and other explanatory data. Then, forecast results from the ARMAX model are used as input to the GARCH model. The GARCH model output includes nonconstant residuals. The ARMAX and GARCH results are combined and used as input to AWNN. The AWNN output is the final price forecast.

A. Price Data Preprocess

A key feature that distinguishes the electricity price series from other time series lies on the assumption that the electricity price is very volatile. Return series has more attractive statistical properties and thus is easier to handle than price series [14]. There are several common definitions of asset return [15]. In this paper, we use the continuously compounded return, also called log return. The one-period continuously compounded return series is defined as

$$R_t = \ln(P_t) - \ln(P_{t-1}) = \ln\left(\frac{P_t}{P_{t-1}}\right). \quad (1)$$

The continuously compounded return enjoys several advantages over the price series. First, the multiperiod return is simply the sum of one-period continuously compounded returns in (2):

$$\begin{aligned} R_t(\tau) &= \ln(P_t) - \ln(P_{t-\tau}) = \sum_{j=0}^{\tau-1} [\ln(P_{t-j}) - \ln(P_{t-j-1})] \\ &= R_t + R_{t-1} + \cdots + R_{t-(\tau-1)}. \end{aligned} \quad (2)$$

Second, statistical properties of the continuously compounded return are more tractable. Fig. 2 shows the hourly electricity prices from January 1, 2006 to May 31, 2006 of the PJM market [13]. Fig. 3 shows the return series during the same period. Comparing the two figures, we learn that the mean value of return series is close to zero and the variability of return series over time looks more homogeneous than that of price series. Thus, statistical characteristics of return series may be better comprehended than those of price series. Therefore, we study the return series of assets in the stationary ARMAX model instead of price series. In the following, we refer to return series as the one-period continuously compounded return as in (1).

Fig. 2. Price series of PJM market from January 1, 2006 to May 31, 2006.

Fig. 3. Return series of PJM market from January 1, 2006 to May 31, 2006.

B. ARMAX Time Series Model

ARMAX is a class of stationary stochastic model. The series in Fig. 2 shows nonequilibrium at a constant mean level, which means the original price series is nonstationary. Using suitable differences, a homogeneous nonstationary time series is transferred to stationary mixed autoregressive-moving average process shown in (3):

$$\phi(B) \cdot (1 - B)^d \cdot \ln(P_t) = \varphi(B) \cdot L_t + \theta(B) \cdot a_t \quad (3)$$

where a_t is a Gaussian $N(0, \sigma_a^2)$ white noise process, $\phi(B) = 1 - \phi_1 \cdot B - \dots - \phi_p \cdot B^p$, $\varphi(B) = 1 - \varphi_1 \cdot B - \dots - \varphi_b \cdot B^b$, and $\theta(B) = 1 - \theta_1 \cdot B - \dots - \theta_q \cdot B^q$.

A homogeneous nonstationary time series is transferred to a stationary time series by taking a proper degree of differencing. From (3), $\ln(P_t)$ is a homogeneous nonstationary time series. By applying a suitable difference of order d , i.e., $R_t(d) = (1 - B)^d \cdot \ln(P_t)$, the new return series $R_t(d)$ is transferred to a stationary stochastic process and fitted in a standard ARMAX (p, q, b) model as

$$\phi(B) \cdot R_t(d) = \varphi(B) \cdot L_t + \theta(B) \cdot a_t. \quad (4)$$

The general ARMAX scheme is described as follows:

1) *Model Identification*: Use the autocorrelation function (ACF) and partial autocorrelation function (PACF) to identify the order of ARMAX (p, q, b) and the suitable difference order d . The autocorrelation of lag k is given as

$$\rho_k = \frac{\sum_{t=1}^{T-k} [R_t(d) - \overline{R(d)}] \cdot [R_{t+k}(d) - \overline{R(d)}]}{\sum_{t=1}^T [R_t(d) - \overline{R(d)}]^2}. \quad (5)$$

The stationary property implies that zeros of $\phi(B)$ lie outside the unit circle, which means that the ACF will die out quickly

Fig. 4. ACF of price series of PJM market from January 1, 2006 to May 31, 2006.

Fig. 5. ACF of return series of PJM market from January 1, 2006 to May 31, 2006.

and rather linearly. Figs. 4 and 5 show the ACF of price series and return series from January 1, 2006 to May 31, 2006 in the PJM market, respectively. Dashed lines indicate the approximate upper and lower confidence bounds. That is, if the ACF at a certain lag is smaller than the 95% confidence bound, we assume there is no significant autocorrelation at that lag. After the first order difference (which is carried out in return series), the ACF dies out quickly after lag 2 with a damping sine-cosine wave; so the price series may follow the process with $d = 1$, which is the one-period return series as defined in (1). Thus inputs and outputs of ARMAX model are all price return series. Furthermore, (p, q, b) orders are determined by lags where ACF and PACF die out.

There are two alternatives to the ARMAX model to forecast a day-ahead electricity price return series. One is to build a single ARMAX model based on the entire series, and then consider a 24-step forecast for the next day. The other is to consider different hourly models. That is, dividing the entire series into 24 sets corresponding to different hours of a day, building ARMAX models based on different hourly series, and forecasting a one step ahead for each ARMAX model. The forecast results of the 24 ARMAX models constitute the day ahead forecast. Figs. 6–8 show the ACF of return series for the first hour and two peak hours, i.e., hours 10 and 20, of each day in the PJM market from January 1, 2006 to May 31, 2006. Comparing Figs. 6–8 with 5, we learn that, although hourly ACFs are not exactly the same, the return series ACF of the same-hour dies out more quickly than the return series of the entire day. Hence by considering the hourly-based series, the ARMAX model can better fit a series with proper AR and MA orders. Here we consider different hourly ARMAX models instead of a single ARMAX model for the entire series.

2) *Parameter Estimation*: After identifying a tentative model, the next step is to estimate the model parameters. The ordinary least squares (OLS) estimation is efficiently used to make inferences about parameters conditional on the adequacy

Fig. 6. ACF of return series for the daily hour 01:00 from January 1, 2006 to May 31, 2006.

Fig. 7. ACF of return series for the daily hour 10:00 from January 1, 2006 to May 31, 2006.

Fig. 8. ACF of return series for the daily hour 20:00 from January 1, 2006 to May 31, 2006.

of the model. Tray *et al.* proposed an iterative regression process to estimate parameters for stationary and nonstationary ARMA models [16].

3) *Diagnostic Checking*: Once parameters are estimated, we check the model adequacy for representing the series which is intended to reveal model inadequacies and consider improvements. One technique that can be used for diagnostic checking is overfitting, i.e., fitting a more elaborate model to show whether additions are needed. The other is the diagnostic check applied to residuals to show if there are any autocorrelations or partial autocorrelations among residuals. If the current model is inadequate, we return to step one and repeat the iterative procedure.

In conclusion, the time series model building is an iterative procedure. It starts with the model identification and the parameter estimation. After the parameter estimation which is used to analyze the adequacy of the model by diagnostic checking, iterative steps of the model building are repeated until a satisfactory model is obtained. One issue that needs to be considered here is that the fit of a regression model to the new data is nearly always worse than its fit to the original data. In this paper, the task is accomplished by separating the series into two parts, with the first portion of the data used for the model construction and the remaining portion for the evaluation of forecasting

Fig. 9. ACF of residuals after the ARMAX is fit to the PJM market from January 1, 2006 to May 31, 2006.

capability. Copas [17] proposed the preshrunk predictor which anticipates the overfitting and gives predictions with a uniformly lower mean squared error.

C. GARCH—Conditional Heteroscedastic Model

It is generally agreed that both price series and return series present nonconstant deviations over time as demonstrated in Figs. 2 and 3. Thus the OLS estimator of ARMAX model coefficients is no longer asymptotically unbiased and consistent, when error terms are autocorrelated. Thus, the residual analysis is an important step in the regression analysis. GARCH models are widespread tools to deal with series conditional standard deviations [18]. A GARCH (p, q) is modeled as (6) where ν_t is a Gaussian $N(0, 1)$ white noise process and $h_t = \text{Var}(\varepsilon_t | \varepsilon_{t-1})$ represents the conditional variance of time t based on time $(t-1)$:

$$h_t = c + \sum_{i=1}^p \alpha_i \cdot h_{t-i} + \sum_{i=1}^q \beta_i \cdot \varepsilon_{t-i}^2$$

$$\varepsilon_t^2 = \nu_t^2 \cdot h_t. \quad (6)$$

The proposed GARCH model described in (6) can forecast beyond one day out. The input series, ε_t , considers the residual of ARMAX model as the actual price minus the forecast from the ARMAX process when the actual price is known, or forecast residual values from the GARCH model when forecasting beyond one day out and the actual price is unknown. The prediction quality deteriorates as the number of predicted hours increases. After combining the results of ARMAX and GARCH models, forecast results incorporate the possibility of nonconstant error variance. The application of GARCH model is an iterative procedure which is similar to the ARMAX model. It includes iterative order determination, parameter estimation, and model diagnostic checking [19].

Fig. 9 shows the ACF of residual series after the ARMAX model is fit to the PJM market from January 1, 2006 to May 31, 2006. This ACF figure suggests that the residual series fails to have a significant serial correlation. Fig. 10 shows the ACF of squared residuals. The autocorrelations at several lags are larger than bounds, which suggest that the residual series may have a conditional heteroscedasticity.

D. Adaptive Wavelet Neural Network (AWNN)

Considering nonlinear and nonstationary impacts of system loads on price does help improve predictions based on time se-

Fig. 10. ACF of squared residuals after the ARMAX is fit to the PJM market from January 1, 2006 to May 31, 2006.

Fig. 11. AWNN model.

ries techniques, especially in the case of sky-high price spikes. AWNN represents a more modern estimation technique for a nonlinear relationship between electricity prices and system loads. AWNN introduces wavelets as activation functions of hidden neurons in traditional feed-forward neural networks with a linear output neuron. The unknown parameters of network include weights and dilation/translation factors which can be learned by gradient-type algorithms. The success of this configuration dwells on the fact that the wavelet network has universal and L^2 approximation properties and is a consistent function estimator [21], [22]. The AWNN structure is shown in Fig. 11.

The output of AWNN is computed as (7) where the multidimensional wavelet function $f(\cdot)$ is calculated by the tensor product of one-dimensional wavelets or some radial functions, and b_{ij} , a_{ij} are translation and dilation parameters:

$$y = \sum_{j=1}^n W_j \cdot f\left(\frac{(W_{1j} \cdot x_1 - b_{1j})}{a_{1j}}, \dots, \frac{(W_{mj} \cdot x_m - b_{mj})}{a_{mj}}\right) + \sum_{i=1}^m W_i \cdot x_i + e. \quad (7)$$

The morlet wavelet shown in (8) is used here as the mother wavelet, and other wavelet functions are dilations and translations derived from this prototype mother wavelet. We compared two most popular mother wavelets given in the literature with numerical tests: Morlet and Mexican Hat. We found that Morlet always gives a better forecast solution. Since dilation parameters $a_{1j}, \dots, a_{mj}$ in (7) are already included for each input, the

usage of 1.75 in (8) is an arbitrary coefficient which will not impact the forecasting accuracy. Multidimensional wavelet function is calculated by the tensor product in (9) and by the radial function in (10):

$$f(x) = \cos(1.75x) \cdot \exp(-x^2/2) \quad (8)$$

$$f((W_{1j} \cdot x_1 - b_{1j})/a_{1j}, \dots, (W_{mj} \cdot x_m - b_{mj})/a_{mj}) = \prod_{i=1}^m \cos[1.75 \cdot (W_{ij} \cdot x_i - b_{ij})/a_{ij}] \cdot \exp\left\{-\left[(W_{ij} \cdot x_i - b_{ij})/a_{ij}\right]^2/2\right\} \quad (9)$$

$$f((W_{1j} \cdot x_1 - b_{1j})/a_{1j}, \dots, (W_{mj} \cdot x_m - b_{mj})/a_{mj}) = \cos\left(1.75 \sqrt{\sum_{i=1}^m [(W_{ij} \cdot x_i - b_{ij})/a_{ij}]^2}\right) \cdot \exp\left(-\sum_{i=1}^m [(W_{ij} \cdot x_i - b_{ij})/a_{ij}]^2/2\right). \quad (10)$$

In the training process, the network learns by adjusting weights as well as translation and dilation parameters by using the product of gradient and learning rate. Two parameters, i.e., learning rate and momentum, are adjusted to accelerate the learning process [19]. The learning rate controls the size of each step for minimizing the objective function. The calculation of momentum term is to average the changes and determine the proportion of past changes that should be used for new values. Thereby, the term ensures that the search path on the average is in the downhill direction.

One of the critical issues in network training is overfitting which means that the network memorizes the training patterns and consequently loses the ability to generalize. That is, it fits the training set but cannot predict the fit for new data sets. Overfitting is especially a serious problem for price forecasting since there are many price spikes which are blended into historical prices.

In the training process, there is a point at which the training error continues to decrease while the generalization error starts to increase. The training process should stop at this point to avoid overfitting. Accordingly, in order to detect overfitting, the original data set is divided into three disjoint sets, i.e., training set, validation set, and generalization set. The training set is used to train the network model, and the validation set is used to estimate the generalization error while the generalization set is for forecasting. In this paper, two indicators are considered together to detect the point of overfitting. One is to check whether the MSE in each training iteration exceeds the average MSE plus its standard deviation, as expressed in (11):

$$MSE = \frac{1}{T} \sum_{t=1}^T (O_t - P_t)^2$$

$$MSE_V^k > \overline{MSE}_V^k + \sigma_V^k. \quad (11)$$

MSE implies an underlying quadratic loss function. It is the assumed loss function for which the conditional mean is the best, i.e., it is the minimum MSE forecast. The other is to measure the generalization factor, given in (12). Overfitting is detected at the training iteration k where $\gamma^k > \chi_\gamma^k$ with χ_γ^k given in (13).

This test always ensures that $\gamma^k \leq 1.0$ before overfitting occurs to make sure that the validation error is smaller than the testing error [22]:

$$\gamma^k = \frac{MSE_V^k}{MSE_T^k} \quad (12)$$

$$\chi_\gamma^k = \min \{ \chi_\gamma^{k-1}, \bar{\gamma}^k + \sigma_\gamma^k, 1.0 \}. \quad (13)$$

ARMAX considers different models for different hours. However, it is not the case for WANN. Two AWNN models are used for weekday and weekend forecasts. Both AWNNs for PJM price forecast studies contain 16 hidden nodes and one output. There are two AWNN input structures, one for predicting weekday prices and the other for weekend prices. For weekday forecasts, nine input data are used at hour t on day D , which are loads at hours $(t-1)$, t and $(t+1)$ on day D , historical prices at hour t on days $(D-1)$ and $(D-2)$, and forecast prices at $(t-3)$, $(t-2)$, $(t-1)$ and t based on the forecast results from ARMAX&GARCH models. For weekend forecasts, 14 input data are used at hour t on day D , which are loads at hours $(t-1)$, t and $(t+1)$ on day D , historical prices at hour t , $(t+1)$ and $(t+2)$ on day $(D-1)$, historical prices at hour $(t-3)$, $(t-2)$, $(t-1)$ and t on day $(D-2)$, and forecast prices at $(t-3)$, $(t-2)$, $(t-1)$ and t based on the forecast results from ARMAX and GARCH models. The selection of input features is based on correlation analysis, and the number of hidden nodes, 16, is based on the forecasting experience in the PJM market, which are all system specific.

The utilization and analysis of large data sets often represent a complex forecasting task. The process of feature selection is regarded as a reduction in dimensionality by choosing a subset of variables as features which are more relevant than others. It is likely that statistically less important components arise from noise which are not relevant to the intrinsic nature of the data. The dimensionality can be reduced by using statistical-based and artificial intelligence algorithms as principal component analysis, factor analysis, feature clustering, etc. [26], [27]. ARMAX considers hourly model structures on each day. However, the only two AWNN models are for weekdays and weekends, respectively.

E. Assessment of Forecasting

Several measurements are used to examine the accuracy of forecast results. The mean absolute percentage error (MAPE) index in (14) is considered here to evaluate the performance of forecast results. MAPE represents the absolute average prediction error between predictions and actual targets:

$$\text{MAPE} = \left(\frac{1}{T} \cdot \sum_{t=1}^T \frac{|O_t - P_t|}{P_t} \right) \cdot 100\%. \quad (14)$$

If the actual value is small, (14) will contribute large terms to MAPE even if the difference between actual and forecast values is small. In addition, if the forecast value is small and actual value is large, the absolute percentage error will be close to 100% [28]. In order to avoid the adverse effect of very small prices, the AMAPE defined in (15) is adopted and compared with those in the literature. For (14) and (15), period T could be hourly, daily, or weekly:

$$\text{AMAPE} = \left(\frac{1}{T} \cdot \sum_{t=1}^T \left[\frac{|O_t - P_t|}{\left(\frac{1}{T} \cdot \sum_{t=1}^T P_t \right)} \right] \right) \cdot 100\%. \quad (15)$$

Before using a single model or a combination of models to predict the future, we assume implicitly that there is a true model or a combination of models for a given series. However, the assumption is rarely accurate. Even if it is true, there is no guarantee that it will be selected as the best fit to the data. Thus the impact of model uncertainty on forecasts needs to be measured [23]. In this paper, we use the variance of forecast errors to measure this uncertainty. The smaller the variance, the less uncertain is the model or more accurate is the forecast results. The variance of error in a time span T is defined as

$$\sigma_E^2 = \frac{1}{T} \cdot \sum_{t=1}^T \left(\left[\frac{|O_t - P_t|}{\left(\frac{1}{T} \cdot \sum_{t=1}^T P_t \right)} \right] - \text{AMAPE} \right)^2. \quad (16)$$

F. Monte Carlo Random Number Generator

Series a_t in the ARMAX model, series v_t in the GARCH model, and noise e in AWNN are regarded as Gaussian processes. Also, gradient algorithms used for the training of AWNN may be sensitive to initial conditions (i.e., weights, translation, and dilation factors). Evenly distributed random numbers would improve the universal search and the convergence process for the training of ARMAX, GARCH, and AWNN models. In this subsection, we describe the application of Monte Carlo method for generating more evenly distributed random numbers. We adopt antithetic variates, a variance reduction technique, to accelerate the convergence of results. A low-discrepancy Monte Carlo simulation method (lattice) is adopted with the possibility of accelerating the convergence rate. Random numbers in the lattice method are more evenly distributed. An n -point lattice rule of rank- r in dimension d is defined as

$$\left\{ \sum_{i=1}^r \frac{k_i}{n_i} v_i \bmod 1, k_i = 0, 1, \dots, n_i - 1 \mid i = 1, \dots, r \right\} \quad (17)$$

where $v_1, \dots, v_r$ are linearly independent d -vector of integers. If we draw N independent samples according to the Monte Carlo simulation method, the iteration ends when the relative standard deviation is less than a predefined value (e.g., 95% relative standard deviation is given as $1.96 \cdot \sigma / \sqrt{N}$ where σ is the standard deviation and N is number of simulations). Usually N exceeds several thousands for a relatively small standard deviation. If the low-discrepancy method is used, the convergence will be accelerated from $O(1/\sqrt{N})$ to nearly $O(1/N)$ and we can use a relatively smaller number of samples to reach the same convergence [24], [25]. The method of antithetic variates is a commonly used control variance method. It attempts to reduce the variance by introducing the negative dependence between pairs of replications. It is based on the observation that $Y_i = F^{-1}(U_i)$ and $\hat{Y}_i = F^{-1}(1 - U_i)$ have a distribution F but are antithetic to each other. The basic idea is that the variance

after including the pair $(Y_i, \tilde{Y}_i)$ is smaller than just using the same size of random numbers generated by the ordinary Monte Carlo method [24], [25]. The emphasis on using the low-discrepancy method and the control variance method, lattice and antithetic variates, will generate more evenly distributed random numbers and accelerate the convergence.

III. CASE STUDIES

The proposed model is applied to predict electricity prices for the PJM market. It is trained and tested using the data set from January 1, 2005 to December 31, 2006. Price data and other supporting information are given in [13]. In all case studies, for the day D's price forecast, the training set includes actual price and load data up to the day before day D. Also, the demand up to one hour ahead the price forecast hour are assumed known. As reported in the literature [34], [35], short-term load forecasting has reached a comfortable state of performance with 1%–2% error. Thus load forecast errors will have very limited impacts on price forecast errors reported in the paper. The cases are listed as follows:

- Case 1) Five single days, selected for each month from January to May 2006 including weekdays and weekends, are forecast and compared with those in [31].
- Case 2) Two weeks, February 1–7, 2006 representing a low load demand week and February 22–28, 2006 representing a high load demand week, are studied and compared with results reported in [31]. Furthermore, in order to investigate the trend in the prediction quality degradation as we increase the number of predicted hours, the forecast is studied based on day-ahead and represented for the whole month of February 2006. The same hybrid model is used for the entire month.
- Case 3) Four one-week periods, the first seven days in each month of February, May, August, and November representing different seasons in 2006, are studied.

The cases are discussed as follows.

1) Case 1: Five single days

For a fair comparison, same five test days used in [31] are considered, which includes January 20, February 10, March 5, April 7, and May 13 in 2006. Five individual models are developed and forecast prices for those five days, respectively. The forecasts are presented in Table I and compared with those in [31]. The AMAPE given in (15) that is also used in [31] is considered for the results in Table I. In Table I and thereafter, the improvement is calculated as: (the difference between the forecast results reported in [31] and the forecast results reported in this paper) divided by (the forecast results reported in [31]). A lower forecast error indicates that results are more accurate. Table I shows the daily AMAPE for selected days. Comparing the daily AMAPE of the proposed forecasts with those in [31], we learn that the consideration of price series deviations and nonlinear characteristics would help improve the forecast accuracy. Table II shows the variance of forecast errors as a measure of the model uncertainty. The smaller the variance, the less uncertain is the model, thus the more accurate are the forecasts. Notable improvements in AMAPEs and error variances of the proposed method as compared to [31] are

TABLE I
COMPARISON OF DAILY AMAPEs FOR CASE 1

Day in 2006	Proposed Method	Results in [31]	Improvement
Jan. 20 th	3.71%	6.93%	46.46%
Feb. 10 th	2.85%	7.96%	64.20%
Mar. 5 th	5.48%	7.88%	30.46%
Apr. 7 th	4.17%	9.02%	53.77%
May 13 th	4.06%	6.91%	41.24%

TABLE II
COMPARISON OF DAILY ERROR VARIANCES FOR CASE 1

Day in 2006	Proposed Method	Results in [31]	Improvement
Jan. 20 th	0.0010	0.0034	70.59%
Feb. 10 th	0.0015	0.0050	70.00%
Mar. 5 th	0.0033	0.0061	45.90%
Apr. 7 th	0.0013	0.0038	65.79%
May 13 th	0.0015	0.0049	69.39%

TABLE III
COMPARISON FOR APRIL 7 FOR THE EFFECT OF GARCH (\$/MWh)

Hour	Actual Price	Proposed method	Without GARCH	Hour	Actual Price	Proposed method	Without GARCH
1	34.33	35.76	35.79	13	64.92	61.91	61.90
2	31.85	35.38	35.92	14	62.50	57.80	58.80
3	31.09	34.49	36.36	15	59.00	51.29	53.32
4	30.32	32.24	32.23	16	53.05	51.10	50.82
5	31.59	31.28	30.67	17	50.13	47.27	47.27
6	38.02	42.41	43.30	18	45.95	45.95	45.85
7	60.59	66.46	65.99	19	49.77	50.38	50.92
8	67.06	68.60	68.88	20	62.25	62.25	62.86
9	68.91	68.82	70.09	21	69.08	69.88	70.57
10	68.72	67.50	67.40	22	63.33	60.96	60.76
11	66.15	66.97	66.97	23	46.45	46.05	46.70
12	70.37	71.90	66.20	24	42.44	40.06	39.87

shown in the last column of Tables I and II. Table III compares the forecast results on April 7 using the proposed method and the method excluding GARCH (that is, only ARMAX and AWNN are used and GARCH is bypassed). Better results are obtained at most hours with GARCH, and the best one occurs at hour 12 with the actual price of 70.37\$/MWh, which is 71.90\$/MWh as compared to 66.20\$/MWh without GARCH. The forecast results with GARCH are slightly worse at hours 4, 7, 14, 15, 23, and the worst one occurs at hour 15, with the actual price of 59.00 \$/MWh, which is 51.29\$/MWh as compared to 53.32\$/MWh without GARCH. The final daily AMAPE of the proposed model is 4.17% as compared with the one without GARCH 4.72%, which indicates that by including GARCH, the final AMAPE for the whole day is improved by about 13.19% (i.e., $(4.72\% - 4.17\%) / 4.17\%$).

Figs. 12 and 13 show the day-ahead price forecasts for chosen days of April 7 and May 13, 2006. It is reported in [31] that the prediction is particularly inaccurate for the morning and evening peaks of April 7, 2006. Fig. 12 shows that the prediction is improved by applying the proposed method for the morning and evening peaks, and the daily AMAPE is improved from 9.02% to 4.17%, with a 53.77% improvement. In Fig. 13, the prediction is improved for the daily and evening peaks especially at hours 9:00 and 21:00. The forecast inaccuracy is improved here especially for very large peaks, which are essential to GENCOs' bidding strategies.

2) Case 2: Two weeks with low and high load demands

Fig. 12. Actual and forecast prices for April 7, 2006.

Fig. 13. Actual and forecast prices for May 13, 2006.

Fig. 14. Actual load profile for February 1–7 and February 22–28, 2006.

Two weeks, February 1–7, 2006 representing a low demand week and February 22–28, 2006 representing a high demand week, are studied. Load profiles for these two weeks are shown in Fig. 14.

Tables IV and V compare the performance of the proposed method with that of [31]. For these two weeks, both the AMAPE and error variance are notably improved. Especially in the week of February 22–28, 2006, the AMAPE is decreased from 8.88% to 5.01%, which is improved by 43.58%. With the proposed forecasting method, the maximal daily AMAPE of 8.25% is even smaller than the weekly AMAPE of 8.88% as reported in [31]. These forecasts are based on day-ahead and represented for one week. That is, the actual prices of the PJM market on February 1, 2006 are used as inputs to forecast the price on February 2, 2006 and so on; however, only one hybrid model is used for the entire week.

The weekly forecasts for February 1–7, 2006 are presented in Fig. 15 which shows price forecasts obtained from the proposed model follow the trend of actual market prices. When price spikes appear during peak hours in the last three days of this week, the proposed model outperforms that in [31] by capturing actual prices more closely as highlighted in Fig. 15. The weekly AMAPE proposed by the hybrid model is 5.27%

TABLE IV
COMPARISON OF WEEKLY AMAPEs FOR CASE 2

Week (2006)		Proposed Method	Results in [31]	Improvement
Feb. 1 st –7 th	Max. Daily AMAPE	8.21%	11.32%	27.47%
	Min. Daily AMAPE	2.98%	5.94%	49.83%
	Weekly AMAPE	5.27%	7.66%	31.20%
Feb. 22 nd –28 th	Max. Daily AMAPE	8.25%	12.37%	33.31%
	Min. Daily AMAPE	2.11%	5.66%	62.72%
	Weekly AMAPE	5.01%	8.88%	43.58%

TABLE V
COMPARISON OF WEEKLY ERROR VARIANCES FOR CASE 2

Week (2006)	Proposed Method	Results in [31]	Improvement
Feb. 1 st –7 th	0.0037	0.0066	43.94%
Feb. 22 nd –28 th	0.0025	0.0047	46.81%

Fig. 15. Actual and forecast prices for February 1–7, 2006.

as compared to 7.66% reported in [31], which shows a 31.20% improvement.

Similarly, weekly forecasts of February 22–28, 2006 are presented in Fig. 16. According to Fig. 14, load patterns for the first five days are similar in these two weeks. Large loads occur in later days of the week, which increase electric prices. In comparison with [31], the proposed weekly AMAPE is decreased from 8.88% to 5.01%, with a 43.58% improvement. Also, the proposed accuracy of forecasts is improved especially for the last day of the week as highlighted. The quality of prediction may deteriorate as the number of predicted hours increases since the same set of hybrid models will be used to for the entire week instead of developing a set of new models for each day.

Table VI gives the forecast error variance, corresponding to the same hours on different days of the week of February 1–7, 2006, to measure the model uncertainty. The smaller the variance, the less uncertain is the model and the more accurate are the forecasts. Variances for off-peak hours are much less than those of peak hours. The largest variances, which are less than 0.008, occur during hours 5–7. The second largest variances of 0.005 occur during hours 19–21 which are the evening. Variances less than 0.002 occur at off-peak hours.

The prediction quality deteriorates gradually as the number of predicted hours increases. In order to show the degradation of the forecast based on the increasing number of predicted hours, forecasts based on the single day-ahead model for the whole month of February 2006 are presented in Fig. 17 and Table VII. The results show that the forecast performance deteriorates slowly as the number of predicted hours increases. As

Fig. 16. Actual and forecast prices for February 22–28, 2006.

TABLE VI
VARIANCE OF HOURLY FORECAST ERRORS FOR FEBRUARY 1–7, 2006 IN CASE 2

Hour	Variance	Hour	Variance	Hour	Variance
1	0.00042	9	0.00202	17	0.00024
2	0.00133	10	0.00242	18	0.00023
3	0.00254	11	0.00374	19	0.00566
4	0.00199	12	0.00044	20	0.00175
5	0.00436	13	0.00031	21	0.00492
6	0.00559	14	0.00029	22	0.00084
7	0.00759	15	0.00052	23	0.00062
8	0.00145	16	0.00120	24	0.00067

Fig. 17. Actual and forecast prices for February 1–28, 2006.

TABLE VII
COMPARISON OF MAPEs FOR THE MONTH OF FEBRUARY 1–28, 2006

Test Week (2006)	Feb. 1 st –7 th	Feb. 8 th –14 th	Feb. 15 th –21 st	Feb. 22 nd –28 th
Weekly AMAPE	5.27%	6.09%	6.26%	6.70%

shown in Table IV, with a newly developed model for the week of February 22–28, 2006, the weekly AMAPE is 5.01%. In comparison, the same period results based on the monthly forecast would increase to 6.70% as shown in Table VII. This test shows that a single model can be applied to several weeks.

The hybrid model would be updated as required if the current forecasting model is not accurate enough. Accordingly, we train the new model offline using the historical data. The technology of incremental learning would be applied for reducing the frequency of developing the new model. The technology would update the existing model in an incremental fashion to accommodate the new data without compromising the performance [36].

3) Case 3: Four one-week periods for seasons in 2006

In this case, four weeks, the first seven days in each month of February, May, August, and November representing different

Fig. 18. Actual and forecast prices for May 1–7, 2006.

Fig. 19. Actual and forecast prices for August 1–7, 2006.

Fig. 20. Actual and forecast prices for November 1–7, 2006.

TABLE VIII
FORECAST RESULTS OF WEEKLY FORECAST PERFORMANCE OF CASE 3

Test Week (2006)	Feb.	May	Aug.	Nov.
Weekly AMAPE	5.27%	4.64%	11.28%	7.70%
Max. Daily AMAPE	8.21%	8.75%	16.04%	11.94%
Min. Daily AMAPE	2.98%	1.79%	5.59%	3.63%
Error Variance	0.0047	0.0026	0.0126	0.0050

seasons in year 2006, are studied. Table VIII shows the forecasts. The smallest weekly AMAPE occurs in the week of May, and the largest occurs in the week of August, which is mainly due to large spikes occurring during that week. Figs. 18–20 show price forecasts for weeks of May, August, and November. The different price curves show seasonal variant volatilities for the PJM electricity market. Daily prices in May and November appear to be more periodic than those in August, and the two weekly forecasts follow the actual prices more closely.

In the week of August 2006, spikes as large as over 350\$/MWh occur on August 3, 2006. Another two spikes occur on peak hours of August 1 and 2, 2006. Fig. 19 shows that the proposed price forecasts follow the trend of actual market price spikes when spikes are directly related to the load values,

Fig. 21. Actual price from January 1, 2006 to August 7, 2006.

TABLE IX
FORECAST FOR THREE LARGE SPIKES FOR THE WEEK OF AUGUST 1–7, 2006

Hour	Actual price (\$/MWh)	Forecast price (\$/MWh)	Error
17:00 on Aug. 1 st , 2006	267.99	223.02	16.78%
17:00 on Aug. 2 nd , 2006	328.04	289.83	11.65%
17:00 on Aug. 3 rd , 2006	333.91	316.61	5.18%

although the spike quantity is not predicted very accurately. Fig. 21 shows the actual price series from January 1, 2006 to August 7, 2006. The spikes, as large as 267.99\$/MWh, occurring on August 1, 2006 are the first large spikes in 2006. Thus, spike forecasts for August 1, 2006 would hardly capture actual spikes, which is mainly due to the lack of historical spike information when the model is built. Although forecast spike magnitudes are smaller than those of actual prices, the proposed algorithm does predict the spike vertex to some level of accuracy. Reference [31] did not report any results on such large spikes in the PJM market. In fact, the literature on price spike forecasts is very limited. Zhao *et al.* [30] forecasted price spikes of the Queensland Electricity market in June 2004 with forecast errors of 20%. Table IX gives the hourly forecasts at peak hours on the first three days. The largest hourly spike forecast error, which is 16.78%, occurs at 17:00 on August 1, 2006, and the smallest, as low as 5.18%, occurs at 17:00 hours on August 3, 2006.

Compared with [30], the accuracy of the proposed price spike forecasts is sufficiently good considering the extreme volatility of spike signals. Furthermore, forecasts capture actual prices very well when prices suddenly drop by about 50% on August 4, 2006 from over 350\$/MWh to as low as 157\$/MWh. Other explanatory factors that may affect electricity prices such as weather, available ancillary services, power exchanges, and the availability of generators and transmission lines are not included in the proposed day-ahead price forecasting model. Such factors are less important for price forecasting in most situations, and their inclusion may cause overfitting or even deteriorate the accuracy of the forecasting method. With modern SCADA/EMS systems, one can monitor/evaluate the power system status and perform very short-time price forecasts with the proposed model, which improves the forecasting of spikes.

IV. CONCLUSIONS

Several case studies are chosen for the PJM electricity market with various levels of price spikes to test and validate

the proposed model. The proposed hybrid time-series and AWNN model, composed of linear and nonlinear relationships of prices and explanatory variables, improves the performance of forecast results. The usage of one-period continuously compounded return series and AWNN has an advantage of modeling nonstationary electricity prices, especially price spikes. The use of AWNN as a consistent function estimator and two overfitting detection indications diminishes the overfitting issue when including history spikes in the training data set for price spikes forecasting. It is observed that the proposed hybrid model outperforms the literature, and considering the extreme volatility of the spike signal, the price spike forecast accuracy level of the proposed model is sufficiently good as compared with those reported in the literature.

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Accelerating the Benders decomposition for network-constrained unit commitment problems

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Abstract This paper presents an optimization method by generating multiple strong Benders cuts for accelerating the convergence of Benders Decomposition (BD) when solving the network-constrained generation unit commitment (NCUC) problem. In NCUC, dc transmission network evaluation subproblems are highly degenerate, which would lead to many dual optimal solutions. Furthermore, the classical BD cuts are often low-density which involve only a limited number of decision variables in the master problem. Therefore, the dual optimal solutions and the corresponding Benders cuts are of crucial importance for improving the efficiency of the BD algorithm. The proposed method would generate multiple strong Benders cuts, which are pareto optimal, among candidates from multiple dual optimal solutions. Such cuts would be high-density in comparison with low-density cuts produced by the classical BD. The proposed multiple strong Benders cuts are efficient in terms of reducing the total iteration number and the overall computing time. The high-density cuts may restrict the feasible region of the master unit commitment (UC) problem in each iteration as they incorporate more decision variables in each Benders cut. The multiple strong Benders cuts would accordingly reduce the iteration number and overall computing time. Numerical tests demonstrate the efficiency of the proposed multiple strong Benders cuts method in comparison with the classical BD algorithm and the linear sensitivity factors (LSF) method. The proposed method can be extended to other applications of BD for solving the large-scale optimization problems in power systems operation, maintenance, and planning.

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Nomenclature

Indices

a, b, m, n	Denote a bus
d, d'	Denote a BD iteration
i, j	Denote a unit
k	Denote a segment of a cost curve function
l, l'	Denote a transmission line
o, o'	Denote a subset
p	Denote a phase shifter
t, τ	Hourly index

Sets and vectors

$\mathbf{B}, \mathbf{B}_o, \mathbf{B}_{o'}$	Set/subsets of buses
$\mathbf{f}(b), \mathbf{t}(b)$	Set of transmission lines starting from bus b /ending at bus b
$\mathbf{PL}_t$	Vector of power flow variables at hour t
$\mathbf{PL}^{\max}$	Vector of power flow upper limit
$\mathbf{U}(b)$	Set of generators located at bus b
$\mathbf{Z}, \mathbf{Z}^c, \mathbf{SZ}_o, \mathbf{SZ}_{o'}$	Sets of buses
$\gamma(m)$	Denote a set of buses, for each bus n in the set, there is a phase shifter at line m to n , and m is the tap side and n is the non-tap side
γ_t	Vector for phase shifter at hour t
$\gamma^{\min}, \gamma^{\max}$	Vector of phase shifter lower/upper limits

Variables

DT_i, UT_i	Number of hours unit i must be initially offline/online due to its minimum off/on time limits
G	Objective value of the global optimal solution to the original problem
I_{it}, P_{it}	Unit commitment decision/generation dispatch of unit i at hour t
LB_d, UB_d	Lower/upper bound of the original problem objective value obtained at BD iteration d
LB_{best}, UB_{best}	Best obtained lower/upper bounds for the objective value to the original problem
$offset$	Offset term in the linear expression of the power loss
OR_{it}, SR_{it}	Non-spinning/spinning reserve provided by unit i at hour t
P_{ikt}	Generation dispatch of unit i at hour t at segment k
P_{Losst}	System loss at hour t
PL_{lt}	Power flow of transmission line l at hour t
q, q_1, q_2, Q	Dual variables for the dual problem
s	Slack variable
SD_{it}, SU_{it}	Shutdown/startup cost of unit i at hour t
θ_{at}, θ_{bt}	Phase angle of bus a and bus b at hour t
θ_{ref}	Phase angle of the reference bus

γ_{abt}	Phase shifter value on the line from bus a to bus b at hour t
λ, κ, π	Dual variables for the primal problem
$ \mathbf{Z} $	Number of buses that belong to set $\mathbf{Z}$
$\hat{\cdot}, \tilde{\cdot}$	Value for variables calculated at previous BD iterations
Constants	
c	A constant integer number determined during the algorithm
C_b	Loss distribution factor corresponding to bus b
c_{ik}, N_i	Incremental cost for segment k and no-load cost of unit i
D_{bt}	System load at bus b hour t
DP_i, UP_i	Shutdown/startup ramp limits of unit i
DR_i, UR_i	Ramping down/ramping up limits of unit i
LF_b	Loss factor related to bus b
LSF_{ab}^m	The sensitivity of the power flow on line l (from bus a to bus b) to power injection at bus m
M, ε	Very large/small positive number
MSR_i	Spinning reserve that can be provided by unit i in one minute
NB	Number of buses
NT	Number of hours under study
P_{Dt}, P_{Lt}	System load/loss at hour t
$P_i^{\min}, P_i^{\max}$	Minimum/maximum capacity of unit i
$P_{ik}^{\max}$	Maximum capacity of unit i of segment k
QSC_i	Quick start capacity of unit i
RO_t, RS_t	System non-spinning/spinning reserve requirements at hour t
T_i^{on}, T_i^{off}	Minimum on/off time limits of unit i
x_{ab}	Line reactance between bus a and bus b
$X_{i0}^{on}, X_{i0}^{off}$	On/off time counter of unit i at the initial status

1 Introduction

In restructured power systems, self-interested entities, including generation companies (GENCOs), transmission companies (TRANSCOs), and distribution companies (DISCOs), are to maximize their own profits and minimize potential risks when participating in power markets. The independent system operator (ISO) coordinates market participants and operates the competitive market efficiently for ensuring a secure and economic operation. Such decisions corresponding to the power system operation, maintenance, and planning are to be made via efficient optimization models and methodologies [1]. Efficient decomposition methods are utilized in large power system optimization problems since most of the optimization problems belong to non-deterministic polynomial-time hard (NP-hard) problems and the solution to the original problem in such cases would be an intractable task without decomposition.

The BD algorithm was first introduced by J.F. Benders [2] for solving large-scale, mixed-integer programming (MIP) problems. BD is a common technique for separating large scale power system problems into several easy-to-solve subproblems. The algorithm is widely adopted in various power system optimization problems including security-constrained unit commitment (SCUC) and security-constrained optimal

power flow (SCOPF) [3–9]. Reference [3] applied BD to SCUC problems for separating the unit commitment (UC) in the master problem from the hourly network security check in subproblems. The subproblems checked the ac network security constraints based on the UC solution to determine whether a converged and secure ac power flow solution would be feasible. If the feasibility conditions could not be satisfied, the feasibility Benders cuts were fed back to the master UC problem for seeking a feasible UC solution based on the added cuts. Reference [4] considered BD applications to generation and transmission planning problems by decoupling the master planning problems from the network evaluation and network security checking subproblems. Reference [5] used the feasibility theorem of BD to derive an analytical condition for determining whether feasible solutions of the original SCUC problems could be obtained from the current dual solution of Lagrangian Relaxation. Reference [6] proposed a BD-based algorithm for calculating a preventive dispatch solution based on a full ac power flow. It solved the optimal power flow in the master problem, and then minimized the real and reactive power by fictitious sources in subproblems. Reference [7] used the generalized BD to solve the large-scale multi-period optimal power flow problem. The problem considered the start-up and shut-down characteristics of thermal units, the transmission network model, and hydraulic equations for integrated hydroelectric plants in a river system. Optimality cuts generated at each iteration provided a lower estimate of total operation cost in the Benders subproblem. Reference [8] applied generalized feasibility Benders cuts for optimizing the post-contingency corrective action in SCUC, which accurately formulated the hourly UC of quick-start units in post-contingency corrective actions via a MIP subproblem instead of linear programming (LP). Reference [9] discussed a general structure of BD for power system decision making applications. Three categories of decision-making problems in power systems for economic, reliability, and risk evaluations were mapped onto Benders subproblems. The applications demonstrated the potential use of BD for solving special structured MIP problems in power systems.

The classical BD algorithm often converges slowly, i.e., the slow convergence would introduce major computational bottlenecks for a MIP problem which has to be solved repeatedly in practical cases. Several studies discussed possible improvements for accelerating the BD convergence. Reference [10] discussed several ways of improving the performance of BD including a judicious selection of optima from the Benders subproblems to generator strong cuts and properly formulate the subsequent BD problems. Reference [11] proposed to generate cuts from the solution of a LP-approximated master problem by relaxing the integrality request for the first several iterations. Similarly, [12] discussed that only a feasible, rather than an optimal, solution of master problem was necessary for subproblems to generate cuts. Therefore, heuristic methods were sought, in place of the optimal solution of master problem, to quickly locate feasible solutions for generating cuts. In this situation, the convergence was not guaranteed since the cuts were only associated with a set of feasible master solutions. On the other hand, [13] proposed to generate inexact cuts which were to derive a good enough dual solution, instead of the optimal dual solution, for subproblems. In such cases, subproblems were very large-scale LP problems which required a substantial computation time to get the solution. Reference [14] applied the subsystems of an infeasible LP to generate feasibility cuts, and computational results

showed that the method converged faster than that with feasibility cuts generated via extreme rays located by the simplex method. Recently, [15] proposed an algorithm to accelerate the BD by exploring the local branching in the neighborhood of the master problem solution. The lower and the upper bounds were simultaneously improved via local branching in which each located feasible solution was used to generator optimality/feasibility cuts.

This paper proposes multiple strong Benders cuts at each iteration to accelerate the convergence of the NCUC problem. The experiments have shown that the drawback of classical BD algorithm resides in the slow convergence for large-scale power system applications [4]. As will be proved in this paper, each strong Benders cut generated through the proposed algorithm is a pareto optimal cut, and the proposed method reduces the number of Benders iterations as well as the overall computing time. The proposed BD strategy can be easily extended to other large-scale optimization problems in power systems.

The rest of the paper is organized as follows. Section 2 presents the NCUC model and the classical BD algorithm. Section 3 proposes two methods for generating multiple strong cuts at each iteration for accelerating convergence, and in the appendix we prove that each generated cut is pareto optimal. Section 4 presents three cases to discuss the effectiveness of the proposed method. The conclusions are drawn in Sect. 5.

2 NCUC problem formulation and solution methodology

The NCUC problem is formulated as a MIP problem shown in (1)–(8). The objective function is to minimize the total operation cost, including incremental cost, no-load cost, and startup/shutdown cost, as shown in (1), subject to a set of system and generating unit constraints. System constraints include the system power balance in (2), and the system spinning and non-spinning reserve requirements in (3). Unit constraints include ramping up/down limits as well as startup/shutdown ramping for individual units in (4), minimum on and off time constraints in (5), real power generation limits in (6), and constraints on spinning and non-spinning reserves provided by individual generators in (7). Only thermal units are modeled in (4)–(7). The formulation of other types of generating units including combined-cycle, cascaded hydro, and pumped storage, is discussed in the authors' previous work [19]. Here, (8) represents the dc network evaluation constraints, which include power balance for each bus b , power flow equation for each transmission line l , and phase shifter and transmission power flow limits. For simplicity, P_{Loss} is given initially as an input which is estimated as a percentage of the system load P_{Dt} . A more accurate loss formulation is given in (9) if the loss factor LF_b is known, which represents the sensitivity of power loss to the bus power injection

$$G = \text{Min} \sum_t \sum_i \left[\sum_k c_{ik} \cdot P_{ikt} + N_i \cdot I_{it} + SU_{it} + SD_{it} \right] \quad (1)$$

$$\text{s.t.} \quad \sum_i P_{it} = P_{Dt} + P_{Loss} \quad (2)$$

$$\sum_i SR_{it} \geq R_{St} \quad (3)$$

$$\sum_i OR_{it} \geq R_{Ot}$$

$$P_{it} - P_{i(t-1)} \leq UR_i \cdot I_{i(t-1)} + UP_i \cdot (I_{it} - I_{i(t-1)}) + P_i^{\max} \cdot (1 - I_{it}) \quad (4)$$

$$P_{i(t-1)} - P_{it} \leq DR_i \cdot I_{it} + DP_i \cdot (I_{i(t-1)} - I_{it}) + P_i^{\max} \cdot (1 - I_{i(t-1)})$$

$$\sum_{t=1}^{UT_i} (1 - I_{it}) = 0, \quad \text{where } UT_i = \max\{0, \min[NT, (T_i^{on} - X_{i0}^{on}) \cdot I_{i0}]\}$$

$$\sum_{\tau=t}^{t+T_i^{on}-1} I_{i\tau} \geq T_i^{on} \cdot (I_{it} - I_{i(t-1)}), \quad \forall t = UT_i + 1, \dots, NT - T_i^{on} + 1$$

$$\sum_{\tau=t}^{NT} [I_{i\tau} - (I_{it} - I_{i(t-1)})] \geq 0, \quad \forall t = NT - T_i^{on} + 2, \dots, NT$$

$$\sum_{t=1}^{DT_i} I_{it} = 0, \quad \text{where } DT_i = \max\{0, \min[NT, (T_i^{off} - X_{i0}^{off}) \cdot (1 - I_{i0})]\} \quad (5)$$

$$\sum_{\tau=t}^{t+T_i^{off}-1} (1 - I_{i\tau}) \geq T_i^{off} \cdot (I_{i(t-1)} - I_{it}),$$

$$\forall t = DT_i + 1, \dots, NT - T_i^{off} + 1$$

$$\sum_{\tau=t}^{NT} [1 - I_{i\tau} - (I_{i(t-1)} - I_{it})] \geq 0, \quad \forall t = NT - T_i^{off} + 2, \dots, NT$$

$$P_{it} = P_i^{\min} \cdot I_{it} + \sum_k P_{ikt} \quad (6)$$

$$0 \leq P_{ikt} \leq P_{ik}^{\max} \cdot I_{it}$$

$$P_i^{\min} \cdot I_{it} \leq P_{it} \leq P_i^{\max} \cdot I_{it}$$

$$P_{it} + SR_{it} \leq P_i^{\max} \cdot I_{it} \quad (7)$$

$$SR_{it} \leq 10 \cdot MSR_i \cdot I_{it}$$

$$OR_{it} = SR_{it} + (1 - I_{it}) \cdot QSC_i$$

$$\sum_{l \in \mathbf{l}(b)} PL_{lt} - \sum_{l \in \mathbf{t}(b)} PL_{lt} = \sum_{i \in \mathbf{U}(b)} P_{it} - D_{bt} - C_b \cdot P_{Loss_t} \quad (8)$$

$$PL_{lt} - (\theta_{at} - \theta_{bt} - \gamma_{abt})/x_{ab} = 0 \quad \text{line } l \text{ is from bus } a \text{ to bus } b$$

$$\gamma^{\min} \leq \gamma_t \leq \gamma^{\max}$$

$$\begin{aligned}
 -\mathbf{PL}^{\max} &\leq \mathbf{PL}_t \leq \mathbf{PL}^{\max} \\
 \theta_{ref} &= 0 \\
 P_{Lt} - \sum_b LF_b \cdot \left(\sum_{i \in \mathbf{U}(b)} P_{it} - D_{bt} \right) - offset &= 0
 \end{aligned} \tag{9}$$

BD is employed to solve the large-scale NCUC problem with a large number of constraints including those in the hourly network evaluation subproblems (8). In applying BD, the original problem described as (1)–(8) is decomposed into a master UC problem (10) and several hourly network evaluation subproblems (11). The master is a MIP problem and subproblems are LP problems. The subproblems examine the master problem solution for satisfying the network constraints. If the subproblem at hour t is infeasible, the corresponding Benders cut in (12) is generated and added to the next iteration of the master UC problem. The iterative process will continue by successively adding Benders cuts until network violations are mitigated. In (11) a unique non-negative slack variable s_t is introduced for all buses. The physical interpretation of a single non-negative slack variable is to diminish the most violated bus power balance iteratively. Reference [16] reported that a single non-negative slack variable strategy would outperform multiple non-negative slack variables at different buses by reducing the overall number of iterations

$$\begin{aligned}
 LB = \text{Min} \quad & \sum_t \sum_i \left[\sum_k c_{ik} \cdot P_{ikt} + N_i \cdot I_{it} + SU_{it} + SD_{it} \right] \\
 \text{S.t.} \quad & \text{Equations (2)–(7)}
 \end{aligned} \tag{10}$$

Benders cuts from all previous iterations

Min s_t

$$\begin{aligned}
 \text{S.t.} \quad & \sum_{l \in \mathbf{f}(b)} PL_{lt} - \sum_{l \in \mathbf{t}(b)} PL_{lt} - s_t \leq \sum_{i \in \mathbf{U}(b)} P_{it} - D_{bt} - C_b \cdot P_{Losst} & \lambda_{1,bt} \\
 & - \sum_{l \in \mathbf{f}(b)} PL_{lt} + \sum_{l \in \mathbf{t}(b)} PL_{lt} - s_t \leq - \sum_{i \in \mathbf{U}(b)} P_{it} + D_{bt} + C_b \cdot P_{Losst} & \lambda_{2,bt} \\
 & PL_{lt} - (\theta_{at} - \theta_{bt} - \gamma_{abt})/x_{ab} = 0 & \kappa_{lt} \\
 & \gamma_{pt} \leq \gamma_p^{\max} & \pi_{1,pt} \\
 & -\gamma_{pt} \leq -\gamma_p^{\min} & \pi_{2,pt} \\
 & PL_{lt} \leq PL_l^{\max} & \pi_{3,lt} \\
 & -PL_{lt} \leq PL_l^{\max} & \pi_{4,lt} \\
 & \theta_{ref,t} = 0 & \pi_t \\
 & 0 \leq s_t
 \end{aligned} \tag{11}$$

If the optimal objective value $\hat{s}_t$ in (11) is larger than the predefined threshold ε , the feasibility Benders cut represented by (12) will be utilized by grouping generators that are located at the same bus

Fig. 1 NCUC procedure with the classical BD method

$$\sum_{b=1}^{NB} \sum_{i \in U(b)} (\hat{\lambda}_{1b,t} - \hat{\lambda}_{2b,t}) \cdot (P_{it} - \hat{P}_{it}) + \hat{s}_t \leq 0 \quad (12)$$

$U(b)$ represents the set of generators located at the same bus b that shares the same dual variables $\hat{\lambda}_{1b,t}$ and $\hat{\lambda}_{2b,t}$, and $\hat{s}_t$ is the current optimal objective value of (11). Figure 1 shows the flowchart of the NCUC problem with the classical BD method. The master UC problem (10) is solved and the dispatch solution $\hat{P}_{it}$ is passed on to the hourly network evaluation subproblems (11). If there is any network violations (i.e. $s_t > \varepsilon$), a feasibility cut in (12) corresponding to the violated hour is generated and fed back to the master UC problem for further iterations. The procedure stops when $s_t \leq \varepsilon$ is satisfied at all hours, no more feasibility Benders cuts are generated, and the final solution to the original NCUC problem is obtained. At each Benders iteration d , the objective value of (10) provides a lower bound LB_d to the original problem, and $UB_d = LB_d + M \cdot \sum_t s_{dt}$ provides an upper bound to the original problem where s_{dt} is the solution of (11) representing the violation at hour t at Benders iteration d . It is noted that by successively appending feasibility cuts to (10) the lower bound obtained at each iteration will be monotonically increasing, i.e. $LB_{d-1} \leq LB_d \leq G$ and $LB_{best} = LB_d$, but that will not be the case with the upper bound. The upper bound for the current iteration may be lower or higher than that in previous iterations, and the best upper bound is the minimum of all obtained values, i.e. $G \leq UB_{best} = \min_d \{UB_d\}$. Assuming the current Benders iteration is d , and the best upper bound is obtained at iteration d' , the stopping criterion $s_t \leq \varepsilon$ is $\frac{UB_{best} - LB_{best}}{LB_{best}} = \frac{(LB_{d'} + M \cdot \sum_t s_{d't}) - LB_d}{LB_d} \leq \frac{M}{LB_d} \cdot NT \cdot \varepsilon$ where $s_{d't}$ is the violation at hour

t obtained at the Benders iteration d' . That is, with a small enough ε , the stopping criterion will force LB_{best} and UB_{best} to be close, which will restrict the final solution to be close enough to the global optimal solution of the original problem. Here, s_t in (11) represents the maximum power imbalance among all buses at hour t ; thus a non-zero s_t means the final solution is not strictly feasible to the original NCUC problem in the sense that there will be at most ε MW violation at each bus. The ε values of 0.01–0.1 are used in our case studies. For power systems with peak loads of thousands to tens of thousands of MW, the violation of less than 0.01–0.1 MW is tolerable and practical. The NCUC is used to determine day-head UC schedules (i.e. 24 hours), and small violations less than 0.01–0.1 MW can be handled by the real-time power system operation with automatic generation control schemes [1].

The linear sensitivity factor (LSF) method could also be used to solve the NCUC problem [1], which replaces (8) with (13). LSF represents the sensitivity of line flows to the bus power injection. The power flow in each line can be calculated by (13), where LSF_{ab}^m represents the sensitivity of power flow of line l (from bus a to bus b) to power injection at bus m . The detailed calculation procedure of LSF_{ab}^m is discussed in [1]. Here, $(\sum_{i:i \in U(m)} P_{it} - D_{mt} - C_m \cdot P_{Losst} + \sum_{n:n \in \gamma(m)} \gamma_{mn}/x_{mn} - \sum_{n:n \in \gamma(n)} \gamma_{mn}/x_{mn})$ represents the total power injection to bus m , where items represent total generation, load demand, losses distributed at bus m , and equivalent power injection from phase shifters to bus m , respectively. Using the LSF method for the solution of NCUC problem, the UC problem described as (1)–(7) is solved first, then we check the power flow on each transmission line at each hour using (13), and append the violated (13) back to the master UC problem for mitigating violations. The procedure will stop when (13) is satisfied for all lines at all hours, and no transmission power flow violation exists. In the case study section, we will see that the LSF method may be efficient for small systems. However, since there is one constraint for each violated transmission line at each hour, LSF may introduce many more constraints than the BD method for large-scale power systems, which makes the UC problem difficult to solve in real time. Thus, decomposition is the only viable option for the solution of the large-scale NCUC problem in real time

$$\begin{aligned}
 -PL_l^{\max} \leq PL_{lt} = \sum_m LSF_{ab}^m \cdot \left(\sum_{i \in U(m)} P_{it} - D_{mt} - C_m \cdot P_{Losst} \right. \\
 \left. + \sum_{n \in \gamma(m)} \gamma_{mn}/x_{mn} - \sum_{m \in \gamma(n)} \gamma_{mn}/x_{mn} \right) \leq PL_l^{\max} \quad (13)
 \end{aligned}$$

3 Accelerating BD via multiple strong Benders cuts

The drawback of the classical BD algorithm presented in Sect. 2 resides in its slow convergence. In this section, we discuss our methodology for accelerating the BD procedure via multiple strong Benders cuts at each iteration. The proposed methodology for generating multiple strong Benders cuts reduces the number of Benders iterations as well as the overall computing time.

3.1 Generate multiple strong Benders cuts from multiple optimal dual solutions

The dual problem of (11) is formulated as (14) which is highly degenerate. In this case, there are many zeros on the right-hand-side with multiple optimal solutions. If one or more of the variables in the basis of a LP problem is zero, the basis is called degenerate. And the LP is highly degenerate if there are many vertices of the feasible region for which the associated basis is degenerate. Since the coefficients of Benders cut (12) are generated using the optimal dual solution of (14), the proper choice of the optimal dual solution and the corresponding Benders cuts would be of crucial importance for the efficiency of the BD algorithm

$$\begin{aligned}
 \text{Max} \quad & \sum_b \left(\sum_{i \in U(b)} P_{it} - D_{bt} - C_b \cdot P_{\text{Loss}t} \right) \cdot (\lambda_{1,bt} - \lambda_{2,bt}) \\
 & + \sum_p (\gamma_p^{\max} \cdot \pi_{1,pt} - \gamma_p^{\min} \cdot \pi_{2,pt}) + \sum_l PL_l^{\max} \cdot (\pi_{3,lt} + \pi_{4,lt}) \\
 \text{S.t.} \quad & (\lambda_{1,at} - \lambda_{2,at}) + (-\lambda_{1,bt} + \lambda_{2,bt}) + \kappa_{lt} + \pi_{3,lt} - \pi_{4,lt} = 0 \\
 & \text{line } l \text{ is from bus } a \text{ to } b \\
 & \sum_a \kappa_{lt}/x_{am} - \sum_b \kappa_{l't}/x_{mb} = 0 \\
 & \text{line } l \text{ is from bus } a \text{ to } m, \text{ line } l' \text{ is from bus } m \text{ to } b, \\
 & m \text{ is not reference bus} \\
 & \sum_a \kappa_{lt}/x_{am} - \sum_b \kappa_{l't}/x_{mb} + \pi_t = 0 \\
 & \text{line } l \text{ is from bus } a \text{ to } m, \text{ line } l' \text{ is from} \\
 & \text{bus } m \text{ to } b, m \text{ is reference bus} \\
 & \kappa_{lt}/x_{ab} + \pi_{1,pt} - \pi_{2,pt} = 0 \\
 & \text{phase shifter } p \text{ is located at line } l, \text{ which is from bus } a \text{ to } b \\
 & - \sum_{b=1}^{NB} (\lambda_{1b,t} + \lambda_{2b,t}) \leq 1 \\
 & \lambda_{1,bt}, \lambda_{2,bt}, \pi_{1,pt}, \pi_{2,pt}, \pi_{3,lt}, \pi_{4,lt} \leq 0, \quad \kappa_{lt}, \pi_t \text{ free}
 \end{aligned} \tag{14}$$

All buses are divided into exclusive subsets $\mathbf{B}_o$ that satisfy $\bigcup_o \mathbf{B}_o = \mathbf{B}$ and $\mathbf{B}_o \cap \mathbf{B}_{o'} = \Phi$, where $\mathbf{B}$ is the set of all buses in the system. A set of new subproblems (15) is generated corresponding to each subset $\mathbf{B}_o$. The idea behind (15) is to find an optimal dual solution which can generate a cut for restricting the feasible region of P_i $i \in U(b)$ and $b \in \mathbf{B}_o$ to the highest possible extent. An optimal solution of (15) is also an optimal solution to the dual problem (14) since all constraints in (14) are included in (15) and the fifth constraint in (15) would force the objective value to be

equal to its optimal value $\hat{s}$, calculated by (11)

$$\begin{aligned}
 \text{Max} \quad & \sum_{b \in \mathbf{B}_o} \sum_{i \in \mathbf{U}(b)} (P_i^{\max} - \varepsilon) \cdot (\lambda_{1b,t} - \lambda_{2b,t}) \\
 & + \sum_{b \notin \mathbf{B}_o} \sum_{i \in \mathbf{U}(b)} (P_i^{\min} + \varepsilon) \cdot (\lambda_{1b,t} - \lambda_{2b,t}) \\
 \text{S.t.} \quad & (\lambda_{1,at} - \lambda_{2,at}) + (-\lambda_{1,bt} + \lambda_{2,bt}) + \kappa_{lt} + \pi_{3,lt} - \pi_{4,lt} = 0 \\
 & \text{line } l \text{ is from bus } a \text{ to } b \\
 & \sum_a \kappa_{lt}/x_{am} - \sum_b \kappa_{l't}/x_{mb} = 0 \\
 & \text{line } l \text{ is from bus } a \text{ to } m, \text{ line } l' \text{ is} \\
 & \text{from bus } m \text{ to } b, m \text{ is not reference bus} \\
 & \sum_a \kappa_{lt}/x_{am} - \sum_b \kappa_{l't}/x_{mb} + \pi_t = 0 \tag{15} \\
 & \text{line } l \text{ is from bus } a \text{ to } m, \text{ line } l' \text{ is from bus } m \text{ to } b, m \text{ is reference bus} \\
 & \kappa_{lt}/x_{ab} + \pi_{1,pt} - \pi_{2,pt} = 0 \\
 & \text{phase shifter } p \text{ is located at line } l, \text{ which is from bus } a \text{ to } b \\
 & \sum_b \left(\sum_{i \in \mathbf{U}(b)} P_{it} - D_{bt} - C_b \cdot P_{\text{Loss}t} \right) \cdot (\lambda_{1,bt} - \lambda_{2,bt}) \\
 & + \sum_p (\gamma_p^{\max} \cdot \pi_{1,pt} - \gamma_p^{\min} \cdot \pi_{2,pt}) + \sum_l PL_l^{\max} \cdot (\pi_{3,lt} + \pi_{4,lt}) = \hat{s}_t \quad \mathcal{Q} \\
 & - \sum_{b=1}^{NB} (\lambda_{1b,t} + \lambda_{2b,t}) \leq 1 \\
 & \lambda_{1,bt}, \lambda_{2,bt}, \pi_{1,pt}, \pi_{2,pt}, \pi_{3,lt}, \pi_{4,lt} \leq 0, \quad \kappa_{lt}, \pi_t \text{ free}
 \end{aligned}$$

The new cut (16) is generated from the optimal solution of (15).

$$\sum_{b=1}^{NB} \sum_{i \in \mathbf{U}(b)} (\tilde{\lambda}_{1,bt} - \tilde{\lambda}_{2,bt}) \cdot P_{it} + \hat{s}_t \leq 0 \tag{16}$$

where $\tilde{\lambda}$ is the new optimal solution to (15).

Definition 1 (See also Magnanti and Wong 1981 [10]) A cut for the minimization of (1)–(8) as $\sum_{b=1}^{NB} \sum_{i \in \mathbf{U}(b)} (\lambda_{1b,t} - \lambda_{2b,t}) \cdot (P_{it} - \hat{P}_{it}) + \hat{s}_t \leq 0$ would dominate or is stronger than $\sum_{b=1}^{NB} \sum_{i \in \mathbf{U}(b)} (\lambda'_{1b,t} - \lambda'_{2b,t}) \cdot (P_{it} - \hat{P}_{it}) + \hat{s}_t \leq 0$ as another cut, if for all $\mathbf{P}_t$ in their domain $\{\mathbf{0}, [\mathbf{P}^{\min}, \mathbf{P}^{\max}]\}$, (17) is satisfied with a strict inequality for

any point in the feasible region.

$$\left[\sum_{b=1}^{NB} \sum_{i \in \mathbf{U}(b)} (\lambda'_{1b,t} - \lambda'_{2b,t}) \cdot (P_{it} - \hat{P}_{it}) + \hat{s}_t \right] - \left[\sum_{b=1}^{NB} \sum_{i \in \mathbf{U}(b)} (\lambda_{1b,t} - \lambda_{2b,t}) \cdot (P_{it} - \hat{P}_{it}) + \hat{s}_t \right] \leq 0 \quad (17)$$

Definition 2 (See also Magnanti and Wong 1981 [10]) A cut is pareto optimal if no other cut could dominate it.

Theorem 1 The cut (16) generated via multiple optimal dual solutions is pareto optimal.

The proof of Theorem 1 is provided in Appendix A. The problem considered in Magnanti and Wong 1981 [10] is a convex hull, and the points $\mathbf{P}_t$ we discuss here belong to a non-convex set $\{\mathbf{0}, [\mathbf{P}^{\min}, \mathbf{P}^{\max}]\}$. The dual to (15), which corresponds to the primal form of the original problem (11), is given in (18). Since dual problems (14)–(15) would introduce many more variables than the primal problem (11), we have experienced that it is more efficient to solve the NCUC problem in its primal form (11) and (18) than its dual form (14)–(15). Furthermore, subproblems (11) and (18) are large and sparse and could experience a higher convergence speed by using a primal-dual logarithmic barrier algorithm provided by CPLEX [17]. This algorithm is suitable for large LP problems with dense columns; that is, a relatively high number of nonzero entries in each column

$$\begin{aligned} \text{Min} \quad & \hat{s}_t \cdot Q + s_t \\ \text{S.t.} \quad & \sum_{l \in \mathbf{f}(b)} PL_{lt} - \sum_{l \in \mathbf{t}(b)} PL_{lt} - s_t + \left(\sum_{i \in \mathbf{U}(b)} P_{it} - D_{bt} - C_b \cdot P_{Losst} \right) \cdot Q \\ & \leq RQ1_{bt} \\ & - \sum_{l \in \mathbf{f}(b)} PL_{lt} + \sum_{l \in \mathbf{t}(b)} PL_{lt} - s_t - \left(\sum_{i \in \mathbf{U}(b)} P_{it} - D_{bt} - C_b \cdot P_{Losst} \right) \cdot Q \\ & \leq RQ2_{bt} \\ & PL_{lt} - (\theta_{at} - \theta_{bt} - \gamma_{abt})/x_{ab} = 0 \\ & \gamma_{pt} + \gamma_p^{\max} \cdot Q \leq \gamma_p^{\max} \\ & -\gamma_{pt} - \gamma_p^{\min} \cdot Q \leq -\gamma_p^{\min} \\ & PL_{lt} + PL_l^{\max} \cdot Q \leq PL_l^{\max} \\ & -PL_{lt} + PL_l^{\max} \cdot Q \leq PL_l^{\max} \\ & \theta_{ref,t} = 0 \\ & 0 \leq s_t, \quad Q \text{ free} \end{aligned} \quad (18)$$

where

$$RQ1_{bt} = \begin{cases} \sum_{i \in U(b)} (P_i^{\max} - \varepsilon), & b \in \mathbf{B}_o \\ \sum_{i \in U(b)} (P_i^{\min} + \varepsilon), & b \notin \mathbf{B}_o \end{cases} \quad \text{and}$$

$$RQ2_{bt} = \begin{cases} -\sum_{i \in U(b)} (P_i^{\max} - \varepsilon), & b \in \mathbf{B}_o \\ -\sum_{i \in U(b)} (P_i^{\min} + \varepsilon), & b \notin \mathbf{B}_o \end{cases}$$

In the implementation of (18), a strong Benders cut (16) is generated for each subset $\mathbf{B}_o$. We should point out that different forms of subsets $\mathbf{B}_o$ might conceivably generate different pareto optimal cuts. The number of subsets may also impact the convergence. More pareto optimal cuts generated in each iteration could result in fewer iterations between the master UC and network evaluation subproblems. However, the solution of the master problem may take longer because of the large number of cuts. Here, the optimal number of subsets would be a tradeoff between the computational burden of solving the master problem and the number of iterations. We use 2 subsets for off peak hours and 6 for peak hours in our case studies. Also, buses that are geographically close are placed into the same subset $\mathbf{B}_o$. In practice, the parameter tuning will be necessary in order to reduce the number of iterations and the overall computing time.

3.2 Generate multiple strong Benders cuts by enhancing the density of cuts

For an optimal dual solution of (14), $\hat{\lambda}_{1,bt}, \hat{\lambda}_{2,bt}, \hat{\pi}_{1,pt}, \hat{\pi}_{2,pt}, \hat{\pi}_{3,lt}, \hat{\pi}_{4,lt}, \hat{\kappa}_{lt}, \hat{\pi}_t$, all buses are divided into two subsets $\mathbf{Z}$ and $\mathbf{Z}^c$, with $\mathbf{Z}$ representing the set of buses b that satisfy $(\hat{\lambda}_{1,bt} - \hat{\lambda}_{2,bt}) = 0$, and $\mathbf{Z}^c$ representing the set of all other buses. Usually the Benders cut (12) is low density which means that a small number of decision variables $\mathbf{P}_t$ is involved. That is, very few coefficients of $\mathbf{P}_t$ are nonzero, which would limit the contribution of Benders cut (12) to strengthening the feasible region of the master UC problem. The idea here is to generate strong Benders cuts for strengthening the master UC problem at each iteration and incorporating more decision variables $\mathbf{P}_t$ at each Benders cut for reducing the number of iterations and the overall computing time.

Based on this idea, we divide the set $\mathbf{Z}$ into exclusive subsets $\mathbf{SZ}_o$, which satisfy $\bigcup_o \mathbf{SZ}_o = \mathbf{Z}$ and $\mathbf{SZ}_o \cap \mathbf{SZ}_{o'} = \Phi$. Here buses in the set $\mathbf{Z}$ that are geographically close are included in the same subset $\mathbf{SZ}_o$. Different partitioning subsets may result in deriving different high density cuts and different convergence performances, which would require more research. A new LP optimization problem (19) is formulated corresponding to each subset $\mathbf{SZ}_o$ for generating high-density Benders cuts. The last inequality constraint in (19) is to guarantee that the problem (19) is bounded. We experience that the value of $2 \cdot |\mathbf{Z}|$ used in problem (19) does not impact the convergence performance of the proposed method significantly as illustrated in Case study 4.2 in which we replace $2 \cdot |\mathbf{Z}|$ with 1. The optimal solution of (19), $\hat{\lambda}_{1,bt}, \hat{\lambda}_{2,bt}$ for $b \in \mathbf{Z}^c$ and $\bar{\lambda}_{1,bt}, \bar{\lambda}_{2,bt}$ for $b \in \mathbf{Z}$, is not feasible for the network evaluation problem (11) or its dual (14) as it violates $-\sum_{b=1}^{NB} (\lambda_{1,bt} + \lambda_{2,bt}) \leq 1$ in (14). Thus (20) is solved to get the final high-density Benders cut given in (21), where $c = \sum_{b \in \mathbf{Z}^c} (-\hat{\lambda}_{1,bt} - \hat{\lambda}_{2,bt}) + 2 \cdot |\mathbf{Z}|$

is constant with the given $\hat{\lambda}_{1,bt}$ and $\hat{\lambda}_{2,bt}$ for $b \in \mathbf{Z}^c$

$$\begin{aligned}
 & \text{Max} \quad \sum_{b \in \mathbf{SZ}_o} \sum_{i \in \mathbf{U}(b)} (P_i^{\max} - \varepsilon) \cdot (\lambda_{1b,t} - \lambda_{2b,t}) \\
 & \quad + \sum_{b \in \{\mathbf{Z} - \mathbf{SZ}_o\}} \sum_{i \in \mathbf{U}(b)} (P_i^{\min} + \varepsilon) \cdot (\lambda_{1b,t} - \lambda_{2b,t}) \\
 & \text{S.t.} \quad (\lambda_{1,at} - \lambda_{2,at}) + (-\lambda_{1,bt} + \lambda_{2,bt}) + \kappa_{lt} + \pi_{3,lt} - \pi_{4,lt} = 0 \\
 & \quad \text{line } l \text{ is from bus } a \text{ to } b \\
 & \quad \sum_a \kappa_{lt}/x_{am} - \sum_b \kappa_{l't}/x_{mb} = 0 \\
 & \quad \text{line } l \text{ is from bus } a \text{ to } m, \text{ line } l' \text{ is from} \\
 & \quad \text{bus } m \text{ to } b, m \text{ is not reference bus} \\
 & \quad \sum_a \kappa_{lt}/x_{am} - \sum_b \kappa_{l't}/x_{mb} + \pi_t = 0 \\
 & \quad \text{line } l \text{ is from bus } a \text{ to } m, \text{ line } l' \text{ is} \\
 & \quad \text{from bus } m \text{ to } b, m \text{ is reference bus} \tag{19} \\
 & \quad \kappa_{lt}/x_{am} + \pi_{1,pt} - \pi_{2,pt} = 0 \\
 & \quad \text{phase shifter } p \text{ is located at line } l, \text{ which is from bus } a \text{ to } b \\
 & \quad \sum_b \left(\sum_{i \in \mathbf{U}(b)} P_{it} - D_{bt} - C_b \cdot P_{\text{Losst}} \right) \cdot (\lambda_{1,bt} - \lambda_{2,bt}) \\
 & \quad + \sum_p (\gamma_p^{\max} \cdot \pi_{1,pt} - \gamma_p^{\min} \cdot \pi_{2,pt}) + \sum_l PL_l^{\max} \cdot (\pi_{3,lt} + \pi_{4,lt}) = \hat{s}_t \quad \mathcal{Q} \\
 & \quad \lambda_{1,bt} = \hat{\lambda}_{1,bt}, \quad b \in \mathbf{Z}^c, \quad q_{1,bt} \\
 & \quad \lambda_{2,bt} = \hat{\lambda}_{2,bt}, \quad b \in \mathbf{Z}^c, \quad q_{2,bt} \\
 & \quad \sum_{b \in \mathbf{Z}} (-\lambda_{1,bt} - \lambda_{2,bt}) \leq 2 \cdot |\mathbf{Z}| \quad q \\
 & \quad \lambda_{1,bt}, \lambda_{2,bt}, \pi_{1,pt}, \pi_{2,pt}, \pi_{3,lt}, \pi_{4,lt} \leq 0, \quad \kappa_{lt}, \pi_t \text{ free} \\
 & \text{Max} \quad \tilde{s}_t = \sum_b \left(\sum_{i \in \mathbf{U}(b)} P_{it} - D_{bt} - C_b \cdot P_{\text{Losst}} \right) \cdot (\lambda_{1,bt} - \lambda_{2,bt}) \\
 & \quad + \sum_p (\gamma_p^{\max} \cdot \pi_{1,pt} - \gamma_p^{\min} \cdot \pi_{2,pt}) + \sum_l PL_l^{\max} \cdot (\pi_{3,lt} + \pi_{4,lt})
 \end{aligned}$$

$$\begin{aligned}
\text{S.t.} \quad & (\lambda_{1,at} - \lambda_{2,at}) + (-\lambda_{1,bt} + \lambda_{2,bt}) + \kappa_{lt} + \pi_{3,lt} - \pi_{4,lt} = 0 \\
& \text{line } l \text{ is from bus } a \text{ to } b \\
& \sum_a \kappa_{lt}/x_{am} - \sum_b \kappa_{l't}/x_{mb} = 0 \\
& \text{line } l \text{ is from bus } a \text{ to } m, \text{ line } l' \text{ is from} \\
& \text{bus } m \text{ to } b, m \text{ is not reference bus} \\
& \sum_a \kappa_{lt}/x_{am} - \sum_b \kappa_{l't}/x_{mb} + \pi_t = 0 \\
& \text{line } l \text{ is from bus } a \text{ to } m, \text{ line } l' \text{ is} \\
& \text{from bus } m \text{ to } b, m \text{ is reference bus} \tag{20} \\
& \kappa_{lt}/x_{am} + \pi_{1,pt} - \pi_{2,pt} = 0 \\
& \text{phase shifter } p \text{ is located at line } l, \text{ which is from bus } a \text{ to } b \\
& - \sum_{b=1}^{NB} (\lambda_{1,bt} + \lambda_{2,bt}) \leq 1 \\
& \lambda_{1,bt} = \hat{\lambda}_{1,bt}/c, \quad \lambda_{2,bt} = \hat{\lambda}_{2,bt}/c, \quad b \in \mathbf{Z}^c, \quad q_{1,bt}, q_{2,bt} \\
& \lambda_{1,bt} = \bar{\lambda}_{1,bt}/c, \quad \lambda_{2,bt} = \bar{\lambda}_{2,bt}/c, \quad b \in \mathbf{Z}, \quad q_{1,bt}, q_{2,bt} \\
& \lambda_{1,bt}, \lambda_{2,bt}, \pi_{1,pt}, \pi_{2,pt}, \pi_{3,lt}, \pi_{4,lt} \leq 0, \quad \kappa_{lt}, \pi_t \text{ free}
\end{aligned}$$

Theorem 2 The cut (21) is pareto optimal, given the fixed coefficients $\hat{\lambda}_{1,bt}$ and $\hat{\lambda}_{2,bt}$ corresponding to all buses in the subset $b \in \mathbf{Z}^c$, which is the optimal solution of (14).

$$\sum_{b \in \mathbf{Z}^c} \sum_{i \in \mathbf{U}(b)} (\hat{\lambda}_{1,bt}/c - \hat{\lambda}_{2,bt}/c) \cdot (P_{it} - \hat{P}_{it}) + \sum_{b \in \mathbf{Z}} \sum_{i \in \mathbf{U}(b)} (\bar{\lambda}_{1,bt}/c - \bar{\lambda}_{2,bt}/c) \cdot P_{it} + \tilde{s}_t \leq 0 \tag{21}$$

The proof of Theorem 2 is provided in Appendix B. The duals to (19)–(20), which correspond to the primal form of the original problem (11), are given in (22)–(23). Similar to (14)–(15), the dual forms (19)–(20) introduce many more variables than their corresponding primal forms (22)–(23). Thus a higher efficiency could be achieved by solving primal problems (22)–(23)

$$\begin{aligned}
\text{Min} \quad & \hat{s}_t \cdot Q + \sum_{b \in \mathbf{Z}^c} (\hat{\lambda}_{1,bt} \cdot q_{1,bt} + \hat{\lambda}_{2,bt} \cdot q_{2,bt}) + 2 \cdot |\mathbf{Z}| \cdot q \\
\text{S.t.} \quad & \sum_{l \in \mathbf{f}(b)} PL_{lt} - \sum_{l \in \mathbf{t}(b)} PL_{lt} \\
& + \left(\sum_{i \in \mathbf{U}(b)} P_{it} - D_{bt} - C_b \cdot P_{\text{Loss}t} \right) \cdot Q + Q1_{bt} \leq RQ1_{bt}
\end{aligned}$$

$$\begin{aligned}
& - \sum_{l \in \mathbf{f}(b)} PL_{lt} + \sum_{l \in \mathbf{t}(b)} PL_{lt} \\
& - \left(\sum_{i \in \mathbf{U}(b)} P_{it} - D_{bt} - C_b \cdot P_{Loss} \right) \cdot Q + Q2_{bt} \leq RQ2_{bt}
\end{aligned} \tag{22}$$

$$PL_{lt} - (\theta_{at} - \theta_{bt} - \gamma_{abt})/x_{ab} = 0$$

$$\gamma_{pt} + \gamma_p^{\max} \cdot Q \leq 0$$

$$-\gamma_{pt} - \gamma_p^{\min} \cdot Q \leq 0$$

$$PL_{lt} + PL_l^{\max} \cdot Q \leq 0$$

$$-PL_{lt} + PL_l^{\max} \cdot Q \leq 0$$

$$\theta_{ref,t} = 0$$

$$0 \leq q, \quad Q, q_{1,bt}, q_{2,bt} \text{ free}$$

where

$$RQ1_{bt} = \begin{cases} \sum_{i \in \mathbf{U}(b)} (P_i^{\max} - \varepsilon), & b \in \mathbf{SZ}_o, \\ \sum_{i \in \mathbf{U}(b)} (P_i^{\min} + \varepsilon), & b \in \mathbf{Z} - \mathbf{SZ}_o, \\ 0, & b \in \mathbf{Z}^c, \end{cases} \quad RQ2_{bt} = -RQ1_{bt}$$

$$Q1_{bt} = \begin{cases} -q, & b \in \mathbf{Z}, \\ q_{1,bt}, & b \in \mathbf{Z}^c, \end{cases} \quad Q2_{bt} = \begin{cases} -q, & b \in \mathbf{Z} \\ q_{2,bt}, & b \in \mathbf{Z}^c \end{cases}$$

$$\text{Min} \quad s_t + \sum_{b \in \mathbf{Z}^c} (\hat{\lambda}_{1,bt} \cdot q_{1,bt} + \hat{\lambda}_{2,bt} \cdot q_{2,bt})/c + \sum_{b \in \mathbf{Z}} (\hat{\lambda}_{1,bt} \cdot q_{1,bt} + \hat{\lambda}_{2,bt} \cdot q_{2,bt})/c$$

$$\begin{aligned}
\text{S.t.} \quad & \sum_{l \in \mathbf{f}(b)} PL_{lt} - \sum_{l \in \mathbf{t}(b)} PL_{lt} - s_t + q_{1,bt} \leq \sum_{i \in \mathbf{U}(b)} P_{it} - D_{bt} - C_b \cdot P_{Loss} \\
& - \sum_{l \in \mathbf{f}(b)} PL_{lt} + \sum_{l \in \mathbf{t}(b)} PL_{lt} - s_t + q_{2,bt} \leq - \sum_{i \in \mathbf{U}(b)} P_{it} + D_{bt} + C_b \cdot P_{Loss} \\
& PL_{lt} - (\theta_{at} - \theta_{bt} - \gamma_{abt})/x_{ab} = 0 \\
& \gamma_{pt} \leq \gamma_p^{\max} \\
& -\gamma_{pt} \leq -\gamma_p^{\min} \\
& PL_{lt} \leq PL_l^{\max} \\
& -PL_{lt} \leq PL_l^{\max} \\
& \theta_{ref,t} = 0 \\
& 0 \leq s_t, \quad q_{1,bt}, q_{2,bt} \text{ free}
\end{aligned} \tag{23}$$

In the implementation of (22)–(23), there is one high-density Benders cut (14) corresponding to each subsets $\mathbf{SZ}_o$, and different divisions of subsets $\mathbf{SZ}_o$ may conceivably generate different cuts. The number of subsets may also impact the convergence. The more cuts added to each iteration would result in fewer iterations between

Fig. 2 NCUC procedure with the proposed accelerating BD algorithm

master UC and network evaluation subproblems, but the solution of master problem may take longer because of the large number of added cuts. Here, 5 subsets are used in our case studies.

The overall computing time is the time for solving the master UC problem and a series of network evaluation subproblems iteratively. Fewer iterations would result in a significant reduction in computing time. However, the calculation of additional cuts could be time consuming. Here subproblems (18) and (22)–(23) with respect to disjunctive subsets would be solved in parallel since they are independent, which will reduce the overall computing time.

Figure 2 shows the flowchart for solving the NCUC problem with the proposed accelerating BD method. In comparison to Fig. 1, if there is a network violation (i.e. $s_t > \varepsilon$), besides the feasibility cuts obtained in (12), we also solve a set of subproblems and generate strong Benders cuts for accelerating the BD algorithm. We solve (18) for each subset B_o and generate strong cuts from multiple dual solutions as in (16). Concurrently, we also solve (22)–(23) for each subset SZ_o and generate high density strong cuts as (21). Here, (18) corresponding to different subsets B_o and

(22)–(23) corresponding to different subset $\mathbf{SZ}_o$ can be solved in parallel. All cuts from (12), (16) and (21) are fed back to the master UC problem for further iterations. The same stopping criterion as that of the classical BD discussed in Sect. 2 is used. This paper does not intend to prove that high density cuts (21) are tighter than cuts (12) generated by the classical BD method. In fact, cuts (16) and (21) generated by the proposed method and the cut (12) generated from the classical BD are all pareto; that is, non of them dominates the others. We observed that the classical BD usually generates low density cuts which involve a small number of decision variables $\mathbf{P}_t$. That is, very few coefficients of $\mathbf{P}_t$ are nonzero. These cuts may not restrict significantly the feasible region of the master UC problem, thus more iterations may be needed. The idea here is to generate additional strong Benders cuts for incorporating more decision variables $\mathbf{P}_t$ at each generated Benders cut and strengthening the master UC problem at each iteration. As shown in numerical examples, the incorporation of multiple strong Benders cuts proposed here can strengthen the master UC problem at each iteration as compared with the single cut generated by the classical BD, and reduce the iteration number and overall computing time.

4 Case studies

Three cases are studied in this section to demonstrate the effectiveness of the proposed strong Benders cuts approach in terms of offering fewer Benders iterations and a shorter CPU time. The first case is a mathematical example which shows how Benders cuts are generated for multiple optimal dual solutions, which is common in large-scale power systems. The second one is a 3-bus power system which shows the effectiveness of high-density cuts. The third example is a large-scale 5663-bus system which shows both aspects of the previous examples. All cases are solved using CPLEX 11.0.0 on a 2.4 GHz personal computer.

4.1 Mathematical example

The problem is described as:

$$\begin{aligned}
 \text{Min} \quad & 6 \cdot P_1 + 8 \cdot P_2 + 10 \cdot P_3 \\
 \text{s.t.} \quad & 1 \cdot I_1 \leq P_1 \leq 10 \cdot I_1, \quad 1 \cdot I_2 \leq P_2 \leq 10 \cdot I_2, \quad 1 \cdot I_3 \leq P_3 \leq 10 \cdot I_3 \\
 & P_1 + P_2 + P_3 = 10, \quad 2 \cdot x_1 + x_2 - 4 \cdot x_4 + P_1 \leq 13 \\
 & x_1 + x_3 - 0.5 \cdot P_2 \leq 2, \quad 3 \cdot x_2 + 0.5 \cdot x_3 + x_4 + P_3 \leq 12.5 \\
 & -x_1 - x_2 - x_3 \leq -7, \quad 0 \leq x_1 \leq 5, \quad 0 \leq x_2 \leq 4, \quad 0 \leq x_3 \leq 3 \\
 & 0 \leq x_4 \leq 2, \quad I_1, I_2, I_3 \in \{0, 1\}
 \end{aligned}$$

Table 1 shows the solution procedure with the classical BD algorithm. The optimal solution is reached after 3 iterations. The primal and dual subproblems for the first iteration are presented in Table 2. By solving the primal subproblem, we get an optimal dual solution of $\lambda_1 = 0, \lambda_2 = -1, \lambda_3 = 0$ with a feasibility Benders cut of $-P_2 \leq -2$.

Table 1 Solution procedure with the classical BD algorithm

Iteration	Solution						Benders cuts
	I_1	I_2	I_3	P_1	P_2	P_3	
1	1	0	0	10	0	0	$-P_2 \leq -2$
2	1	1	0	8	2	0	$0.0625 \cdot P_1 - 0.34375 \cdot P_2 + 0.25 \cdot P_3 \leq -0.375$
3	1	1	0	7.538	2.462	0	–

Table 2 Primal and dual subproblems in the first iteration

Subproblem in the primal form				Subproblem in the dual form			
Min	s			Max	$3 \cdot \lambda_1 + 2 \cdot \lambda_2 + 12.5 \cdot \lambda_3 - 7 \cdot \pi_1 + 5 \cdot \pi_2$		
S.t.	$2 \cdot x_1 + x_2 - 4 \cdot x_4 - s \leq 13 - \hat{P}_1$	λ_1			$+ 4 \cdot \pi_3 + 3 \cdot \pi_4 + 2 \cdot \pi_5$		
	$x_1 + x_3 - s \leq 2 + 0.5 \cdot \hat{P}_2$	λ_2		S.t.	$2 \cdot \lambda_1 + \lambda_2 - \pi_1 + \pi_2 \leq 0$		
	$3 \cdot x_2 + 0.5 \cdot x_3 + x_4 - s \leq 12.5 - \hat{P}_3$	λ_3			$\lambda_1 + 3 \cdot \lambda_3 - \pi_1 + \pi_3 \leq 0$		
	$-x_1 - x_2 - x_3 \leq -7$	π_1			$\lambda_2 + 0.5 \cdot \lambda_3 - \pi_1 + \pi_4 \leq 0$		
	$0 \leq x_1 \leq 5$	π_2			$-4 \cdot \lambda_1 + \lambda_3 + \pi_5 \leq 0$		
	$0 \leq x_2 \leq 4$	π_3			$-\lambda_1 - \lambda_2 - \lambda_3 \leq 1$		
	$0 \leq x_3 \leq 3$	π_4			$\lambda_1, \lambda_2, \lambda_3, \pi_1, \pi_2, \pi_3, \pi_4, \pi_5 \leq 0$		
	$0 \leq x_4 \leq 2$	π_5					
	$0 \leq s$						

The dual subproblem in Table 2 has multiple optimal solutions and the above solution is the one chosen by the LP solver. Based on the LP theory, there are infinite optimal solutions for this dual subproblem because the linear combination of any two optimal solutions is also an optimal solution. According to (18), we optimize two extra problems (i.e., subset $\mathbf{B}_1$ including all three buses, and subset $\mathbf{B}_2$ including non) as presented in Table 3. When shifted to the right-hand side, coefficients of P_1 and P_3 are negative and coefficients of P_2 is positive, by considering the $\mathbf{B}_1$ subset the most strict feasibility region of P_2 is found that can be fed back to the master problem. Similarly, by considering non in $\mathbf{B}_2$ subset, we find the most restrict feasibility region of P_1 and P_3 . Accordingly, a new dual optimal solution is obtained for both problems as $\lambda_1 = -0.0625, \lambda_2 = -0.6875, \lambda_3 = -0.25$ with the corresponding cut of $0.0625 \cdot P_1 - 0.34375 \cdot P_2 + 0.25 \cdot P_3 \leq -0.375$. The problem is solved in two iterations with multiple strong Benders cuts generated via multiple dual optimal solutions and shown in Table 4. Here, a reduction of 33.3% is achieved in the number of iterations while the same global optimal solution is obtained. For comparison, this problem is solved directly by CPLEX without decomposition. The computation time with CPLEX is 0.11 second, with the global optimal solution of $P_1 = 7.538, P_2 = 2.462, x_1 = 3.231, x_2 = 3.769, x_4 = 1.192, I_1 = I_2 = 1$ which is the same as that obtained by the proposed accelerating BD algorithm.

Table 3 Subproblems for obtaining multiple dual optimal solutions as shown in (18)

Subproblem corresponding to subset $\mathbf{B}_1$		Subproblem corresponding to subset $\mathbf{B}_2$	
Min	$s + Q$	Min	$s + Q$
S.t.	$2 \cdot x_1 + x_2 - 4 \cdot x_4 - s + 3 \cdot Q \leq -9.99$	S.t.	$2 \cdot x_1 + x_2 - 4 \cdot x_4 - s + 3 \cdot Q \leq -1.01$
	$x_1 + x_3 - s + 2 \cdot Q \leq 4.995$		$x_1 + x_3 - s + 2 \cdot Q \leq 0.505$
	$3 \cdot x_2 + 0.5 \cdot x_3 + x_4 - s + 12.5 \cdot Q \leq -9.99$		$3 \cdot x_2 + 0.5 \cdot x_3 + x_4 - s + 12.5 \cdot Q \leq -1.01$
	$-x_1 - x_2 - x_3 - 7 \cdot Q \leq 0$		$-x_1 - x_2 - x_3 - 7 \cdot Q \leq 0$
	$x_1 + 5 \cdot Q \leq 5$		$x_1 + 5 \cdot Q \leq 5$
	$x_2 + 4 \cdot Q \leq 4$		$x_2 + 4 \cdot Q \leq 4$
	$x_3 + 3 \cdot Q \leq 3$		$x_3 + 3 \cdot Q \leq 3$
	$x_4 + 2 \cdot Q \leq 2$		$x_4 + 2 \cdot Q \leq 2$
	$0 \leq x_1, x_2, x_3, x_4, s \quad Q \text{ free}$		$0 \leq x_1, x_2, x_3, x_4, s \quad Q \text{ free}$

Table 4 Solution procedure using the proposed multiple cuts from multiple optimal dual solutions

Iteration	Solution						Benders cuts
	I_1	I_2	I_3	P_1	P_2	P_3	
1	1	0	0	10	0	0	$-P_2 \leq -2$ $0.0625 \cdot P_1 - 0.34375 \cdot P_2 + 0.25 \cdot P_3 \leq -0.375$
2	1	1	0	7.538	2.462	0	–

4.2 3-bus system

A 3-bus system shown in Fig. 3 with three generators, three transmission lines, and one load is studied. Three generators are located at three buses respectively, with parameters listed in Table 5. Transmission line capacities are also given in Fig. 3. Reactance of all lines is 0.1 p.u. and bus 1 is the reference bus. A one-hour NCUC problem described by (1)–(2), (6) and (8) is considered to find the optimal UC decisions and generation dispatch with minimum operation cost, while satisfying the system load of 450 MW located at bus 3. For this one-hour case study, other constraints, such as reserve requirement, system losses, generator minimum on/off time constraints, and ramping up/down limits, are relaxed for the sake of discussion. The problem is formulated as follows with constraints in each row representing the system load balance, generation capacity limits for each unit, power balance for each bus, dc power flow equation for each transmission line, power flow capacity limits for each line, and the reference bus identification

$$\begin{aligned}
 \text{Min} \quad & 10 \cdot P_{11} + 11 \cdot P_{21} + 12 \cdot P_{31} \\
 \text{S.t.} \quad & P_{11} + P_{21} + P_{31} = 450 \\
 & 100 \cdot I_{11} \leq P_{11} \leq 500 \cdot I_{11}, \quad 90 \cdot I_{21} \leq P_{21} \leq 400 \cdot I_{21} \\
 & 30 \cdot I_{31} \leq P_{31} \leq 200 \cdot I_{31} \\
 & PL_{11} + PL_{31} = P_{11}, \quad PL_{21} - PL_{11} = P_{21}
 \end{aligned}$$

Fig. 3 One-line diagram of the 3-bus system

Table 5 Generator parameters

Generator	$P^{\min}$ (MW)	$P^{\max}$ (MW)	Cost function (\$/MWh)
1	100	500	10
2	90	400	11
3	30	200	12

Table 6 Solution procedure using classical BD algorithm

Iteration	UC solution (MW)			Benders cuts
	P_{11}	P_{21}	P_{31}	
1	450	0	0	$P_{11} \leq 375$
2	360	90	0	$-P_{31} \leq -25$
3	375	0	75	$P_{11} - P_{21} \leq 345$
4	330	90	30	$P_{21} - P_{31} \leq 45$
5	315	90	45	–

$$-PL_{21} - PL_{31} = P_{31} - 450$$

$$PL_{11} - (\theta_{11} - \theta_{21})/0.1 = 0, \quad PL_{21} - (\theta_{21} - \theta_{31})/0.1 = 0$$

$$PL_{31} - (\theta_{11} - \theta_{31})/0.1 = 0$$

$$-115 \leq PL_{11} \leq 115, \quad -165 \leq PL_{21} \leq 165, \quad -260 \leq PL_{31} \leq 260$$

$$\theta_{11} = 0, \quad I_{11}, I_{21}, I_{31} \in \{0, 1\}$$

Applying the classical BD algorithm as described by (10)–(12), we would need 5 iterations between the master UC and the network evaluation subproblems with only 3 transmission lines to eliminate the network violations. Four feasibility Benders cuts are generated as shown in the last row of Table 6. The final optimal solution is to commit all three generators with a dispatch of 315 MW, 90 MW and 45 MW. This example shows the drawback of the classical BD algorithm, which is partly due to the low-density cuts generated in the first two iterations. That is, only one variable is incorporated in each cut, which would limit the algorithm's capability for reducing the feasible region of the master problem.

Next, we show that the proposed method would generate high-density strong Benders cuts for reducing the number of Benders iterations to 3 and the overall computing time. First the network evaluation subproblem (11) is solved, which is shown in the first row of Table 7. We obtain a feasibility Benders cut $P_{11} \leq 375$ with the opti-

Table 7 Subproblems (11), (22)–(23) corresponding to $SZ_1 = \{2\}$

Subproblem (11)	Min	s_1	
	S.t.	$PL_{11} + PL_{31} - s_1 \leq 450$	$\lambda_{1,11}$
		$-PL_{11} - PL_{31} - s_1 \leq -450$	$\lambda_{2,11}$
		$PL_{21} - PL_{11} - s_1 \leq 0$	$\lambda_{1,21}$
		$-PL_{21} + PL_{11} - s_1 \leq 0$	$\lambda_{2,21}$
		$-PL_{21} - PL_{31} - s_1 \leq -450$	$\lambda_{1,31}$
		$PL_{21} + PL_{31} - s_1 \leq 450$	$\lambda_{2,31}$
		$PL_{11} - (\theta_{11} - \theta_{21})/0.1 = 0$	$\kappa_{11}, \quad PL_{21} - (\theta_{21} - \theta_{31})/0.1 = 0 \quad \kappa_{21}$
		$PL_{31} - (\theta_{11} - \theta_{31})/0.1 = 0$	κ_{31}
		$PL_{11} \leq 115$	$\pi_{3,11}, \quad -PL_{11} \leq 115 \quad \pi_{4,11}$
		$PL_{21} \leq 165$	$\pi_{3,21}, \quad -PL_{21} \leq 165 \quad \pi_{4,21}$
		$PL_{31} \leq 260$	$\pi_{3,31}, \quad -PL_{31} \leq 260 \quad \pi_{4,31}$
		$\theta_{11} = 0$	$\pi_1, \quad 0 \leq s_1$
Subproblem (22)	Min	$75 \cdot Q + 0 \cdot q_{1,11} + (-1) \cdot q_{2,11} + 4 \cdot q$	
	S.t.	$PL_{11} + PL_{31} + 450 \cdot Q + q_{1,11} \leq 0$	$\lambda_{1,11}$
		$-PL_{11} - PL_{31} - 450 \cdot Q + q_{2,11} \leq 0$	$\lambda_{2,11}$
		$PL_{21} - PL_{11} + 0 \cdot Q - q \leq 399.99$	$\lambda_{1,21}$
		$-PL_{21} + PL_{11} - 0 \cdot Q - q \leq -399.99$	$\lambda_{2,21}$
		$-PL_{21} - PL_{31} + (-450) \cdot Q - q \leq 30.01$	$\lambda_{1,31}$
		$PL_{21} + PL_{31} - (-450) \cdot Q - q \leq -30.01$	$\lambda_{2,31}$
		$PL_{11} - (\theta_{11} - \theta_{21})/0.1 = 0, \quad PL_{21} - (\theta_{21} - \theta_{31})/0.1 = 0$	
		$PL_{31} - (\theta_{11} - \theta_{31})/0.1 = 0$	
		$PL_{11} + 115 \cdot Q \leq 0, \quad -PL_{11} + 115 \cdot Q \leq 0$	
		$PL_{21} + 165 \cdot Q \leq 0, \quad -PL_{21} + 165 \cdot Q \leq 0$	
		$PL_{31} + 260 \cdot Q \leq 0, \quad -PL_{31} + 260 \cdot Q \leq 0$	
		$\theta_{ref,t} = 0$	
		$0 \leq q, \quad Q, q_{1,11}, q_{2,11}$	free
Subproblem (23)	Min	$s_1 + (-1/5) \cdot q_{2,11} + (-1.263/5) \cdot q_{2,21} + (-2.737/5) \cdot q_{2,31}$	
	S.t.	$PL_{11} + PL_{31} - s_1 + q_{1,11} \leq 450$	$\lambda_{1,11}$
		$-PL_{11} - PL_{31} - s_1 + q_{2,11} \leq -450$	$\lambda_{2,11}$
		$PL_{21} - PL_{11} - s_1 + q_{1,21} \leq 0$	$\lambda_{1,21}$
		$-PL_{21} + PL_{11} - s_1 + q_{2,21} \leq 0$	$\lambda_{2,21}$
		$-PL_{21} - PL_{31} - s_1 + q_{1,31} \leq -450$	$\lambda_{1,31}$
		$PL_{21} + PL_{31} - s_1 + q_{2,31} \leq 450$	$\lambda_{2,31}$
		$PL_{11} - (\theta_{11} - \theta_{21})/0.1 = 0 \quad \kappa_{11}, \quad PL_{21} - (\theta_{21} - \theta_{31})/0.1 = 0 \quad \kappa_{21}$	
		$PL_{31} - (\theta_{11} - \theta_{31})/0.1 = 0 \quad \kappa_{31}$	
		$PL_{11} \leq 115 \quad \pi_{3,11}, \quad -PL_{11} \leq 115 \quad \pi_{4,11}$	
		$PL_{21} \leq 165 \quad \pi_{3,21}, \quad -PL_{21} \leq 165 \quad \pi_{4,21}$	
		$PL_{31} \leq 260 \quad \pi_{3,31}, \quad -PL_{31} \leq 260 \quad \pi_{4,31}$	
		$\theta_{ref,t} = 0$	
		$0 \leq s_1, \quad q_{1,11}, q_{2,11}, q_{1,21}, q_{2,21}, q_{1,31}, q_{2,31}$	free

Table 8 Solution procedure using the proposed high-density cuts

Iteration	UC solution (MW)			Benders cuts
	P_{11}	P_{21}	P_{31}	
1	450	0	0	$P_{11} \leq 375$ $0.2 \cdot P_{11} + 0.253 \cdot P_{21} - 0.547 \cdot P_{31} \leq 75$ $0.2 \cdot P_{11} - 0.0875 \cdot P_{21} + 0.0571 \cdot P_{31} \leq 75$
2	330	90	30	$P_{21} - P_{31} \leq 45$
3	315	90	45	–

mal dual solution of $\lambda_{2,11} = \pi_{3,11} = \pi_{3,31} = -1$, all others are zero, and $\hat{s} = 75$, which is a low density cut that only contains variable P_{11} . Thus at the first iteration, the set $\mathbf{Z}$ contains two buses 2 and 3, and set $\mathbf{Z}^c$ contains bus 1, since the corresponding dual variables for generators 2 and 3 (i.e., $\lambda_{1,21}, \lambda_{2,21}, \lambda_{1,31}, \lambda_{2,31}$) are all zero. ε is assumed to be 0.01 in (22). Two optimization subproblems are constructed according to the primal form (22) with $\mathbf{SZ}_1 = \{2\}$ and $\mathbf{SZ}_2 = \{3\}$ respectively for the fixed $\lambda_{1,11} = 0, \lambda_{2,11} = -1, \hat{s}_t = 75$. The two solutions are $\lambda_{1,21} = 0, \lambda_{2,21} = -1.263, \lambda_{1,31} = -2.737, \lambda_{2,31} = 0$ and $\lambda_{1,21} = -0.429, \lambda_{2,21} = 0, \lambda_{1,31} = 0, \lambda_{2,31} = 0.286$. We apply these to the primal problem (23) which would generate the following two high-density cuts: $0.2 \cdot P_{11} + 0.253 \cdot P_{21} - 0.547 \cdot P_{31} \leq 75$ and $0.2 \cdot P_{11} - 0.0875 \cdot P_{21} + 0.0571 \cdot P_{31} \leq 75$. Here c is equal to 5. In Table 7, we give the detailed mathematical formulations for subproblems (22)–(23) corresponding to $\mathbf{SZ}_1 = \{2\}$.

These two cuts are high density because decision variables in the master problem, P_{11}, P_{21} and P_{31} , are all incorporated in these two cuts; thus they can better restrict the feasible region of the master problem. Appending these three feasibility cuts to the master problem, a solution of 330 MW, 90 MW and 30 MW is obtained. Repeating the above procedures by solving the network evaluation subproblem (11), we obtain the feasibility Benders cut $P_{21} - P_{31} \leq 45$ for the second iteration, with $\lambda_{2,21} = \lambda_{1,31} = \kappa_{31} = -0.5, \kappa_{11} = \kappa_{21} = 0.5, \pi_{3,21} = -1.5$, all others are zero, and $\hat{s} = 7.5$. Thus, at this iteration, the set $\mathbf{Z}$ contains only bus 1 and set $\mathbf{Z}^c$ contains buses 2 and 3. Here, one optimization problem is constructed according to the primal form (22), with $\mathbf{SZ}_1 = \{1\}$, for the fixed $\lambda_{1,21} = 0, \lambda_{2,21} = -0.5, \lambda_{1,31} = -0.5, \lambda_{2,31} = 0, \hat{s}_t = 7.5$. The solution is $\lambda_{1,11} = 0, \lambda_{2,11} = 0$, which means no more high-density cuts can be generated at this iteration, and there is no need to further optimize the primal form (23). If we append the feasibility cut $P_{21} - P_{31} \leq 45$ obtained in this iteration to the master problem, a solution of 315 MW, 90 MW and 45 MW is obtained.

If we repeat the above procedure, the optimal objective value of (11) will be equal to zero which means that there will be no more violations in the network evaluation subproblem. Thus the current solution is optimal and the BD procedure stops. The procedure is shown in Table 8.

Benders cuts presented in the last column of Tables 6 and 8 are mapped onto the $P_{21} - P_{31}$ plane for comparison, which are shown in Figs. 4 and 5, respectively. The mapping is processed by substituting P_{11} with $450 - P_{21} - P_{31}$, which is derived from the system power balance constraint. The domains of P_{21} and P_{31} , $\{P_{21} =$

Fig. 4 Benders cuts from the classical BD algorithm mapped onto $P_{21} - P_{31}$ plane

Fig. 5 Benders cuts from the proposed method mapped onto $P_{21} - P_{31}$ plane

$0, P_{31} = 0\} \cup \{90 \leq P_{21} \leq 400, P_{31} = 0\} \cup \{P_{21} = 0, 30 \leq P_{31} \leq 200\} \cup \{90 \leq P_{21} \leq 400, 30 \leq P_{31} \leq 200\}$, are also shown in Figs. 4 and 5. The Benders cuts 1–4 correspond to the four cuts in Tables 6 and 8 respectively. The optimal points $p_1 - p_5$ obtained at each iteration in Table 6 and optimal points $p_1 - p_3$ at each iteration in Table 8 are also shown. Here, Cuts 1 and 4 are the same in both methods. The Cut 3 coincides in the two methods, i.e., by substituting P_{11} with $450 - P_{21} - P_{31}$, the Cut 3 in Table 6 becomes $2P_{21} + P_{31} \geq 105$ and the Cut 3 in Table 8 becomes $0.2875P_{21} + 0.1429P_{31} \geq 15$, which is $2.0119P_{21} + P_{31} \geq 104.9685$. The Cut 2 from Table 8 provides a tighter formulation than Cut 2 from Table 6, i.e., it passes through the domain boundary $\{90 \leq P_{21} \leq 400, P_{31} = 0\}$ and restricts a tighter feasibility region. The meshed areas in Figs. 4 and 5 show the feasibility regions at the final iteration bounded by Benders cuts and the domain. In Fig. 5, the high density Cuts 2 and 3 generated at the first iteration would tighten the feasibility region of the master problem. These two high density cuts would eliminate the two feasible solutions obtained in the classical BD algorithm and shown as p_2 and p_3 in Fig. 4; thus they would reduce the number of iterations by two as compared with that of the classical BD algorithm. By comparison, the proposed method outperforms the classical BD

Table 9 Solution procedure using the proposed method with tuning parameter

Iteration	UC Solution (MW)			Benders cuts
	P_{11}	P_{21}	P_{31}	
1	450	0	0	$P_{11} \leq 375$ $0.2 \cdot P_{11} + 0.0947 \cdot P_{21} - 0.1053 \cdot P_{31} \leq 75$ $0.2 \cdot P_{11} - 0.0875 \cdot P_{21} + 0.0571 \cdot P_{31} \leq 75$
2	330	90	30	$P_{21} - P_{31} \leq 45$
3	315	90	45	–

algorithm in the sense that it would offer the same reduced feasible region in fewer iterations and smaller overall computing time.

In the above study, $2 \cdot |\mathbf{Z}|$ is used as the right-hand-side for the last inequality constraint in (22) to guarantee that the problem (22) is bounded. In comparison, we use 1 instead of $2 \cdot |\mathbf{Z}|$ to show the impact of this parameter on convergence. Table 9 shows that the problem is solved in three iterations and the same global optimal solution is derived. As compared with Table 8, when using 1 instead of $2 \cdot |\mathbf{Z}|$, the strong cuts are not exactly the same but the UC solution at iteration 2 is the same as that in Table 8. The total number of iterations and generated cuts are the same in the two cases with the same final solution, which shows that the parameter $2 \cdot |\mathbf{Z}|$ does not significantly impact the convergence in this case. This small problem is also directly solved by CPLEX with the computation time of 0.04 second and the global optimal solution of $P_{11} = 315$, $P_{21} = 90$, $P_{31} = 45$, $I_{11} = I_{21} = I_{31} = 1$, $PL_{11} = 75$, $PL_{21} = 165$, $PL_{31} = 240$, $\theta_{11} = 0$, $\theta_{21} = -7.5$, and $\theta_{31} = -24$, which is the same as that obtained by the proposed accelerating BD algorithm. For Cases 4.1 and 4.2, the purpose of reporting the solutions with CPLEX is to show the effectiveness of the proposed accelerating BD algorithm. In the following Case 4.3, we will see that the NCUC problem for large-scale power systems may take much longer to be solved directly by CPLEX, and the proposed accelerating BD algorithm can efficiently solve the problem by delivering good enough solutions within acceptable time frames.

4.3 5663-bus system

A large-scale system with 599 generators, 5663 buses, 7036 transmission lines, and 251 phase shifters is used to illustrate the effectiveness of the proposed methodology. A 24-hour NCUC problem is considered to find the optimal UC decisions and generation dispatch with the minimum operation cost, while satisfying the system loads, reserve requirements, and losses for a 24-hour horizon shown in Fig. 6. All UC and dc transmission network constraints described by (2)–(8) are considered in this case. Table 10 shows the complexity of the large-scale power system optimization problem. It is noted that the number of dc network constraints in (8) (excluding upper and lower limits for phase shifters and transmission flow variables) is even larger than the number of UC constraints in (2)–(7), which indicates that the decomposition is the only option for handling large-scale power system optimization problems with a substantial network structure.

Fig. 6 System loads, reserves, and losses for a 24-hour horizon

Table 10 Complexity of the 5663-bus system

	# of binary variables	# of continuous variables	# of UC constraints in (2)–(7)	# of dc network constraints in (8)
Peak hour problem	1,797	19,318	10,323	12,700
24-hour problem	43,128	457,608	274,268	304,800

- Case 1: Comparison of the proposed method with the classical BD algorithm at the peak hour 16 with a peak load of 62,000 MW.
- Case 2: Comparison of the proposed method with the classical BD algorithm for the 24-hour study.
- Case 3: Appending the initial cuts and studying its impact on convergence.

Case 1: The peak hour is studied using the classical BD algorithm (12) and the proposed strong Benders cuts (16) and (21). Figure 7 shows the NCUC convergence. The proposed method would give a steeper ascent to the violation and speed up the convergence. Table 11 compares the number of iterations and cuts, total CPU time, and the operation cost between the classical BD algorithm and the proposed strong Benders cuts method. We also provide the solution by using the LSF for comparison. The CPU time is based on multiple CPUs, which enables the parallel calculation of hourly network checking subproblems, and the parallel calculation of (18) for all subset $\mathbf{B}_o$ and (22)–(23) for all subset $\mathbf{SZ}_o$. The classical BD algorithm would need 18 iterations with a total of 17 cuts and a total CPU time of 118 s, most of which is consumed by iterations between UC and hourly network evaluation subproblems. In comparison, with the proposed strong Benders cuts, only 8 iterations are needed and the total CPU time is 25 s, which is almost one-fifth of the time used by the classical BD algorithm. A total of 23 cuts are generated in which 13 are from multiple optimal dual solutions and another 3 for enhancing the cut density. For this case, the difference between the proposed method and the classical BD algorithm is even more evident. The proposed method converges more rapidly in terms of the total number of iterations by restricting the feasible region of the master problem at each iteration via strong Benders cuts.

Fig. 7 Classical and multiple strong Benders cuts for the peak hour

Table 11 Comparison of the results in Case 1

	# of iterations	# of cuts	CPU time (s)	Operation cost (\$)
Classical BD algorithm	18	17	118	1,745,451.8
LSF	4	129	11	1,747,353.5
Multiple strong Benders cuts	8	23	25	1,777,264.2
CPLEX Directly	—	—	67	1,747,360.4

The violation threshold of 0.1 MW is used here. The LSF uses fewer iterations and less CPU time than the strong Benders cuts method for this one-hour NCUC problem. However, LSF introduces many more network evaluation constraints than the strong Benders cuts method, which will cause a longer study period for the master UC problem since the master UC is a NP-hard problem. As shown in Cases 2–3, the CPU time for LSF and strong Benders cuts are comparable. The last row of Table 11 shows the operation cost for the three methods. The three solutions are suboptimal since the problem is NP-hard. In this case, the operation cost based on the proposed multiple strong Benders cuts is about 1.82% (i.e. $(1,777,264.2 - 1,745,451.8)/1,745,451.8$) higher than that of the classical BD algorithm. However, the proposed multiple strong Benders cut method reduces of the number of iterations by 55.56% and the CPU time by 78.81%, and provides a similar operation cost as compared to the classical BD algorithm. Hence the proposed method outperforms the classical BD algorithm by providing a good enough solution with a much smaller computation time. This peak hour NCUC problem can be directly solved by CPLEX in 67 seconds. The objective is \$1,747,360.4 with the MIP gap tolerance of 0.05%. In comparison to the solutions given in Table 11, the proposed multiple strong Benders cuts obtained an operation cost that is 1.71% (i.e. $(1,777,264.2 - 1,747,360.4)/1,747,360.4$) higher than that of CPLEX, while saving a computation time of more than 62.69% (i.e. $(67 - 25)/67$).

Case 2: In this case, the system is studied for a 24-hour period. Figure 8 compares the NCUC convergence of the classical BD with that of the proposed strong Benders cuts method. The classical BD algorithm takes 27 iterations vs. 16 for the proposed

Fig. 8 Classical and strong Benders cuts for the 24-hour case study

Fig. 9 CPU time at each iteration in Case 2

Table 12 Comparison of the results for the 24-hour study

	# of iterations	# of cuts	CPU time (s)	Operation cost (\$)
Classical BD algorithm	27	409	3008	28,652,220.7
LSF	7	1693	1713	28,607,073.8
Multiple strong Benders cuts	16	881	2159	28,660,027.6

strong Benders cuts method. A total of 881 cuts are generated for limiting the feasible region of the master problem during the iterative process in which 491 strong cuts are derived from the multiple optimal dual solutions and another 110 for enhancing the cut density. Table 12 compares the number of iterations and cuts, total CPU time, and the operation cost of the classical BD algorithm, the strong Benders cuts, and the LSF method. The proposed strong Benders cuts method reduces the number of iterations by 40.74% (i.e. $(27 - 16)/27$) and saves the CPU time by 28.22% (i.e. $(3008 - 2159)/3008$) as compared to the classical BD algorithm. In this case, the operation cost obtained by LSF is the lowest, and the cost by multiple strong Benders cuts is about 0.027% (i.e. $(28,660,027.6 - 28,652,220.7)/28,652,220.7$) higher than that of the classical BD algorithm. Figure 9 shows that it takes more time to solve the master UC at each iteration with the LSF method since the LSF introduces many more constraints than the strong Benders cuts method. The LSF introduces 1,693 network evaluation constraints vs. 812 in the strong Benders cuts method. Although LSF takes 7 iterations, which is less than half of the 16 for the strong Benders cuts

Fig. 10 Classical and strong Benders cuts for the 24-hour study with initial cuts

method, the required CPU time of LSF is only 20.66% (i.e. $(2159 - 1713)/2159$) smaller than that of the strong Benders cuts method. When solving the master UC problem successively, the solution at the previous iteration can be used as a starting point for the existing UC. Figure 9 shows that a smaller CPU time is used progressively at each iteration of the BD algorithm since only a limited number of Benders cuts are introduced into the master problem at each iteration and the solution at the previous iteration always provides a good starting point. In contrast, the LSF method introduces more constraints at each iteration, all generation dispatch decision variables are considered which would make the problem more difficult to be solved, and the solution of previous iteration may not be used as the starting point. Hence, the CPU time for each LSF iteration is not dramatically reduced as compared with that of the BD algorithm. This 24-hour NCUC problem can not be solved without decomposition by the current version of CPLEX. It takes 2,389 seconds to just solve the root node LP problem, which is generated by relaxing integrality requests of the NCUC problem. Furthermore, after running for more than 3 hours, the CPLEX could not locate a feasible solution to the NCUC problem at any MIP gap level.

Case 3: A good set of effective initial Benders cuts could reduce the number of iterations between the master problem and subproblems [10]. In this case, the hourly NCUCs are first solved in parallel while ignoring startup and shutdown costs and coupling constraints among UC hours (e.g. min on/off time and ramping up/down rate limits) to generate an initial set of Benders cuts [18]. The Benders cuts resulting from the hourly NCUC solution are considered as initial Benders cuts for the 24-hour NCUC solution. Figure 10 shows the NCUC convergence for the classical BD and the strong Benders cuts methods with 603 initial Benders cuts generated by solving the hourly NCUC. The classical BD algorithm takes 12 iterations with a total of 90 cuts. The strong Benders cuts method takes 6 iterations with a total of 294 cuts in which 185 strong cuts are derived from the multiple optimal dual solutions and another 26 are high-density cuts. For a fair comparison, the same set of initial Benders cuts are adopted in the LSF method. The difference between the three operation costs is less than 1% (i.e., $28,566,540.3 - 28,548,341.2 / 28,548,341.2 = 0.064\%$). Compared with the solutions given in Tables 12, 13 shows that the inclusion of initial Benders cuts would dramatically reduce the number of iterations and cuts for both the classical BD algorithm and the strong Benders cuts methods.

Table 13 Comparison of the results for the 24-hour study with initial cuts

	# of iterations	# of cuts	CPU time (s)	Operation cost (\$)
Classical BD algorithm	12	90	2797	28,548,341.2
LSF	5	711	1665	28,566,540.3
Strong Benders cuts	6	294	1584	28,554,679.8

The number of iterations is reduced by 55.56% and 62.5% respectively (i.e., $(27 - 12)/27$ and $(16 - 6)/16$), and the number of cuts is decreased by about 78.00% (i.e., $(409 - 90)/409$) for the classical BD algorithm and 66.63% (i.e., $(881 - 294)/881$) for the strong Benders cuts. However, the total CPU time for the classical BD algorithm is decreased only by about 7% (i.e., $(3008 - 2797)/3008$) and 21.63% (i.e., $(2159 - 1584)/2159$) for the strong Benders cuts. Here, the total CPU time reduction is not significant as may be expected because by appending 603 initial cuts, the required CPU time for each UC master problem would be longer which would diminish the saving in time when initial cuts are used. With initial cuts, the LSF takes 5 iterations as compared with 6 for the strong Benders cuts method, and the CPU time for these two methods are comparable in this case. The strong Benders cuts method would take 4.86% (i.e., $(1665 - 1584)/1665$) less CPU time than the LSF method.

5 Conclusions

This paper proposed a method for generating multiple strong Benders cuts to accelerate the convergence of NCUC with BD. The generated strong Benders cuts are proved to be pareto optimal. Numerical tests show that as compared to the classical BD algorithm, multiple strong Benders cuts generated by the proposed method result in a significant reduction in terms of total number of iterations and the CPU time. For large systems, the proposed multiple strong Benders cuts method and the LSF method are comparable in terms of good enough solutions and CPU time. The proposed multiple strong Benders cuts method also requires fewer cuts than that of the LSF methods. The proposed strong Benders cuts method can be easily extended to other applications of BD on large-scale optimization problems in power systems operation, maintenance and planning.

Appendix A

Proof for Theorem 1 Suppose to the contrary that (16) is not pareto optimal. That is, there exists a cut (A.1) that dominates (16)

$$\sum_{b=1}^{NB} \sum_{i \in U(b)} (\lambda'_{1,bi} - \lambda'_{2,bi}) \cdot P_{it} + \hat{s}_t \leq 0 \quad (\text{A.1})$$

Then from Definition 2, it is true that for all $\mathbf{P}_t$ in their domain of $\{\mathbf{0}, [\mathbf{P}^{\min}, \mathbf{P}^{\max}]\}$

$$\left\{ \left[\sum_{b=1}^{NB} \sum_{i \in \mathbf{U}(b)} (\tilde{\lambda}_{1,bt} - \tilde{\lambda}_{2,bt}) \cdot P_{it} + \hat{s}_t \right] - \left[\sum_{b=1}^{NB} \sum_{i \in \mathbf{U}(b)} (\lambda'_{1,bt} - \lambda'_{2,bt}) \cdot P_{it} + \hat{s}_t \right] \right\} \leq 0 \quad (\text{A.2})$$

Thus (A.2) is true for $P_{it} = P_i^{\max} - \varepsilon, \forall i \in \mathbf{U}(b), b \in \mathbf{B}_o$, and $P_{it} = P_i^{\min} + \varepsilon, \forall i \in \mathbf{U}(b), b \notin \mathbf{B}_o$, which is

$$\left\{ \begin{aligned} & \left[\sum_{b \in \mathbf{B}_o} \sum_{i \in \mathbf{U}(b)} (\tilde{\lambda}_{1,bt} - \tilde{\lambda}_{2,bt}) \cdot (P_i^{\max} - \varepsilon) \right. \\ & \quad \left. + \sum_{b \notin \mathbf{B}_o} \sum_{i \in \mathbf{U}(b)} (\tilde{\lambda}_{1,bt} - \tilde{\lambda}_{2,bt}) \cdot (P_i^{\min} + \varepsilon) \right] \\ & - \left[\sum_{b \in \mathbf{B}_o} \sum_{i \in \mathbf{U}(b)} (\lambda'_{1,bt} - \lambda'_{2,bt}) \cdot (P_i^{\max} - \varepsilon) \right. \\ & \quad \left. + \sum_{b \notin \mathbf{B}_o} \sum_{i \in \mathbf{U}(b)} (\lambda'_{1,bt} - \lambda'_{2,bt}) \cdot (P_i^{\min} + \varepsilon) \right] \end{aligned} \right\} \leq 0 \quad (\text{A.3})$$

However, solving the maximization problem (15), we obtain the optimal objective value as $\sum_{b \in \mathbf{B}_o} \sum_{i \in \mathbf{U}(b)} (\tilde{\lambda}_{1,bt} - \tilde{\lambda}_{2,bt}) \cdot (P_i^{\max} - \varepsilon) + \sum_{b \notin \mathbf{B}_o} \sum_{i \in \mathbf{U}(b)} (\tilde{\lambda}_{1,bt} - \tilde{\lambda}_{2,bt}) \cdot (P_i^{\min} + \varepsilon)$, which means

$$\left\{ \begin{aligned} & \left[\sum_{b \in \mathbf{B}_o} \sum_{i \in \mathbf{U}(b)} (\tilde{\lambda}_{1,bt} - \tilde{\lambda}_{2,bt}) \cdot (P_i^{\max} - \varepsilon) \right. \\ & \quad \left. + \sum_{b \notin \mathbf{B}_o} \sum_{i \in \mathbf{U}(b)} (\tilde{\lambda}_{1,bt} - \tilde{\lambda}_{2,bt}) \cdot (P_i^{\min} + \varepsilon) \right] \\ & - \left[\sum_{b \in \mathbf{B}_o} \sum_{i \in \mathbf{U}(b)} (\lambda'_{1,bt} - \lambda'_{2,bt}) \cdot (P_i^{\max} - \varepsilon) \right. \\ & \quad \left. + \sum_{b \notin \mathbf{B}_o} \sum_{i \in \mathbf{U}(b)} (\lambda'_{1,bt} - \lambda'_{2,bt}) \cdot (P_i^{\min} + \varepsilon) \right] \end{aligned} \right\} \geq 0 \quad (\text{A.4})$$

Using (A.3) and (A.4), we have

$$\left\{ \begin{aligned} & \left[\sum_{b \in \mathbf{B}_o} \sum_{i \in \mathbf{U}(b)} (\tilde{\lambda}_{1,bt} - \tilde{\lambda}_{2,bt}) \cdot (P_i^{\max} - \varepsilon) \right. \\ & \quad \left. + \sum_{b \notin \mathbf{B}_o} \sum_{i \in \mathbf{U}(b)} (\tilde{\lambda}_{1,bt} - \tilde{\lambda}_{2,bt}) \cdot (P_i^{\min} + \varepsilon) \right] \\ & - \left[\sum_{b \in \mathbf{B}_o} \sum_{i \in \mathbf{U}(b)} (\lambda'_{1,bt} - \lambda'_{2,bt}) \cdot (P_i^{\max} - \varepsilon) \right. \\ & \quad \left. + \sum_{b \notin \mathbf{B}_o} \sum_{i \in \mathbf{U}(b)} (\lambda'_{1,bt} - \lambda'_{2,bt}) \cdot (P_i^{\min} + \varepsilon) \right] \end{aligned} \right\} = 0 \quad (\text{A.5})$$

Since (A.1) dominates (16), according to Definition 1 there must exist a $\tilde{\mathbf{P}}$ in the domain of $\{\mathbf{0}, [\mathbf{P}^{\min}, \mathbf{P}^{\max}]\}$ by which the strict inequality of (A.2) is satisfied as shown in (A.6)

$$\left\{ \left[\sum_{b=1}^{NB} \sum_{i \in \mathbf{U}(b)} (\tilde{\lambda}_{1,bt} - \tilde{\lambda}_{2,bt}) \cdot \tilde{P}_i \right] - \left[\sum_{b=1}^{NB} \sum_{i \in \mathbf{U}(b)} (\lambda'_{1,bt} - \lambda'_{2,bt}) \cdot \tilde{P}_i \right] \right\} < 0 \quad (\text{A.6})$$

Next we show that there exists a scalar $\theta > 1$ such that $\theta \cdot (P_i^{\max} - \varepsilon) + (1 - \theta) \cdot \tilde{P}_i$ and $\theta \cdot (P_i^{\min} + \varepsilon) + (1 - \theta) \cdot \tilde{P}_i$ are both in the range of $\{\mathbf{0}, [\mathbf{P}^{\min}, \mathbf{P}^{\max}]\}$.

1. If $\tilde{P}_i = 0$, $\theta \cdot (P_i^{\max} - \varepsilon) + (1 - \theta) \cdot \tilde{P}_i = \theta \cdot (P_i^{\max} - \varepsilon)$ and $\theta \cdot (P_i^{\min} + \varepsilon) + (1 - \theta) \cdot \tilde{P}_i = \theta \cdot (P_i^{\min} + \varepsilon)$. Thus for small $0 \leq \varepsilon$ and $1 < \theta \leq \min\{\frac{P_i^{\max}}{P_i^{\max} - \varepsilon}, \frac{P_i^{\max}}{P_i^{\min} + \varepsilon}\}$, $\theta \cdot (P_i^{\max} - \varepsilon) + (1 - \theta) \cdot \tilde{P}_i$ and $\theta \cdot (P_i^{\min} + \varepsilon) + (1 - \theta) \cdot \tilde{P}_i$ are both in the range of $[\mathbf{P}^{\min}, \mathbf{P}^{\max}]$.
2. If $\tilde{P}_i \in [P_i^{\min}, P_i^{\max}]$, for θ that satisfies $1 < \theta \leq \frac{P_i^{\max} - P_i^{\min}}{P_i^{\max} - P_i^{\min} - \varepsilon}$, we have $\frac{\theta}{\theta - 1} \cdot \varepsilon \geq P_i^{\max} - P_i^{\min}$. Thus $\frac{\theta}{\theta - 1} \cdot \varepsilon \geq P_i^{\max} - P_i^{\min} \geq P_i^{\max} - \tilde{P}_i$, and we have $\theta \cdot (P_i^{\max} - \varepsilon) + (1 - \theta) \cdot \tilde{P}_i - P_i^{\max} = (\theta - 1) \cdot (P_i^{\max} - \tilde{P}_i - \frac{\theta}{\theta - 1} \cdot \varepsilon) \leq 0$, which derives $\theta \cdot (P_i^{\max} - \varepsilon) + (1 - \theta) \cdot \tilde{P}_i \leq P_i^{\max}$. For small $0 \leq \varepsilon$, it usually holds that $P_i^{\max} - P_i^{\min} - \varepsilon \geq \varepsilon$ since $P_i^{\max}$ and $P_i^{\min}$ are usually in tens and hundreds of MW range, and an ε of 0.01–0.1 MW is used in this paper. Thus $1 < \theta \leq \frac{P_i^{\max} - P_i^{\min}}{P_i^{\max} - P_i^{\min} - \varepsilon} \leq \frac{P_i^{\max} - P_i^{\min}}{\varepsilon}$, and we have $\theta \cdot (P_i^{\max} - \varepsilon) + (1 - \theta) \cdot \tilde{P}_i - P_i^{\min} \geq \theta \cdot (P_i^{\max} - \varepsilon) + (1 - \theta) \cdot P_i^{\max} - P_i^{\min} = P_i^{\max} - P_i^{\min} - \theta \cdot \varepsilon \geq 0$, which derives $P_i^{\min} \leq \theta \cdot (P_i^{\max} - \varepsilon) + (1 - \theta) \cdot \tilde{P}_i$. Similarly, we derive that $\theta \cdot (P_i^{\min} + \varepsilon) + (1 - \theta) \cdot \tilde{P}_i$ is in the range of $[\mathbf{P}^{\min}, \mathbf{P}^{\max}]$.

Based on the above discussion, we multiply (A.5) by θ and (A.6) by $(1 - \theta)$ which is negative and preserves the inequality, and add them up to derive

$$\begin{aligned} & \sum_{b \in \mathbf{B}_o} \sum_{i \in \mathbf{U}(b)} (\tilde{\lambda}_{1,bt} - \tilde{\lambda}_{2,bt}) \cdot [\theta \cdot (P_i^{\max} - \varepsilon) + (1 - \theta) \cdot \tilde{P}_i] \\ & + \sum_{b \notin \mathbf{B}_o} \sum_{i \in \mathbf{U}(b)} (\tilde{\lambda}_{1,bt} - \tilde{\lambda}_{2,bt}) \cdot [\theta \cdot (P_i^{\min} + \varepsilon) + (1 - \theta) \cdot \tilde{P}_i] \\ & > \sum_{b \in \mathbf{B}_o} \sum_{i \in \mathbf{U}(b)} (\lambda'_{1,bt} - \lambda'_{2,bt}) \cdot [\theta \cdot (P_i^{\max} - \varepsilon) + (1 - \theta) \cdot \tilde{P}_i] \\ & + \sum_{b \notin \mathbf{B}_o} \sum_{i \in \mathbf{U}(b)} (\lambda'_{1,bt} - \lambda'_{2,bt}) \cdot [\theta \cdot (P_i^{\min} + \varepsilon) + (1 - \theta) \cdot \tilde{P}_i] \quad (\text{A.7}) \end{aligned}$$

According to (A.7)

$$P_{it} = \begin{cases} \theta \cdot (P_i^{\max} - \varepsilon) + (1 - \theta) \cdot \tilde{P}_i, & \forall i \in \mathbf{U}(b), b \in \mathbf{B}_o \\ \theta \cdot (P_i^{\min} + \varepsilon) + (1 - \theta) \cdot \tilde{P}_i, & \forall i \in \mathbf{U}(b), b \notin \mathbf{B}_o \end{cases}$$

$$\left\{ \begin{aligned} & \left[\sum_{b \in \mathbf{B}_o} \sum_{i \in \mathbf{U}(b)} (\hat{\lambda}_{1,bt} - \hat{\lambda}_{2,bt}) \cdot (P_{it} - \hat{P}_{it}) \right. \\ & \quad \left. + \sum_{b \notin \mathbf{B}_o} \sum_{i \in \mathbf{U}(b)} (\tilde{\lambda}_{1,bt} - \tilde{\lambda}_{2,bt}) \cdot P_{it} + \hat{s}_t \right] \\ & - \left[\sum_{b \in \mathbf{B}_o} \sum_{i \in \mathbf{U}(b)} (\hat{\lambda}_{1,bt} - \hat{\lambda}_{2,bt}) \cdot (P_{it} - \hat{P}_{it}) \right. \\ & \quad \left. + \sum_{b \notin \mathbf{B}_o} \sum_{i \in \mathbf{U}(b)} (\lambda'_{1,bt} - \lambda'_{2,bt}) \cdot P_{it} + \hat{s}_t \right] \end{aligned} \right\} > 0$$

which is inconsistent with (A.2). Hence our assumption of (16) not being pareto optimal is untenable. Thus (16) is pareto optimal. $\square$

Appendix B

The following Theorem B.1 is a prerequisite for the proof of Theorem 2.

Theorem B.1 Let $\{\hat{\lambda}_{1,bt}/c, \hat{\lambda}_{2,bt}/c, b \in \mathbf{Z}^c, \bar{\lambda}_{1,bt}/c, \bar{\lambda}_{2,bt}/c, b \in \mathbf{Z}\}$ together with $\{\bar{\pi}_{1,pt}, \bar{\pi}_{2,pt}, \bar{\pi}_{3,lt}, \bar{\pi}_{4,lt}, \bar{\pi}_t, \bar{\kappa}_{lt}\}$ be an optimal solution of (20) with the objective value of $\bar{s}_t$. Thus $\hat{s} \leq c \cdot \bar{s}_t$ is satisfied, where $\hat{s}_t$ is the optimal objective value of (11) used in (19).

Proof for Theorem B.1 First let us show that the following problem (B.1) has the optimal objective value of $c \cdot \bar{s}_t$. Assume the optimal objective value of (B.1) is O

$$\begin{aligned} \text{Max} \quad & \sum_b \left(\sum_{i \in \mathbf{U}(b)} P_{it} - D_{bt} - C_b \cdot P_{\text{Loss}t} \right) \cdot (\lambda_{1,bt} - \lambda_{2,bt}) \\ & + \sum_p (\gamma_p^{\max} \cdot \pi_{1,pt} - \gamma_p^{\min} \cdot \pi_{2,pt}) + \sum_l PL_l^{\max} \cdot (\pi_{3,lt} + \pi_{4,lt}) \\ \text{S.t.} \quad & (\lambda_{1,at} - \lambda_{2,at}) + (-\lambda_{1,bt} + \lambda_{2,bt}) + \kappa_{lt} + \pi_{3,lt} - \pi_{4,lt} = 0 \\ & \text{line } l \text{ is from bus } a \text{ to bus } b \\ & \sum_a \kappa_{lt}/x_{am} - \sum_b \kappa_{l't}/x_{mb} = 0 \\ & \text{line } l \text{ is from bus } a \text{ to bus } m, \text{ line } l' \text{ is from bus } m \text{ to bus } b, \\ & m \text{ is not reference bus} \\ & \sum_a \kappa_{lt}/x_{am} - \sum_b \kappa_{l't}/x_{mb} + \pi_t = 0 \\ & \text{line } l \text{ is from bus } a \text{ to bus } m, \text{ line } l' \text{ is from bus } m \text{ to bus } b, \\ & m \text{ is reference bus} \\ & \kappa_{lt}/x_{ab} + \pi_{1,pt} - \pi_{2,pt} = 0 \\ & \text{phase shifter } p \text{ is located at line } l, \text{ which is from bus } a \text{ to bus } b \\ & - \sum_{b \in \mathbf{Z}} (\lambda_{1,bt} + \lambda_{2,bt}) \leq 2 \cdot |\mathbf{Z}| \end{aligned} \tag{B.1}$$

$$\begin{aligned}\lambda_{1,bt} &= \hat{\lambda}_{1,bt}, & \lambda_{2,bt} &= \hat{\lambda}_{2,bt}, & b &\in \mathbf{Z}^c \\ \lambda_{1,bt} &= \bar{\lambda}_{1,bt}, & \lambda_{2,bt} &= \bar{\lambda}_{2,bt}, & b &\in \mathbf{Z} \\ \lambda_{1,bt}, \lambda_{2,bt}, \pi_{1,pt}, \pi_{2,pt}, \pi_{3,lt}, \pi_{4,lt} &\leq 0, & \kappa_{lt}, \pi_t &\text{ free}\end{aligned}$$

It is obvious that $\{\hat{\lambda}_{1,bt}, \hat{\lambda}_{2,bt}, b \in \mathbf{Z}^c, \bar{\lambda}_{1,bt}, \bar{\lambda}_{2,bt}, b \in \mathbf{Z}\}$ together with $\{c \cdot \bar{\pi}_{1,pt}, c \cdot \bar{\pi}_{2,pt}, c \cdot \bar{\pi}_{3,lt}, c \cdot \bar{\pi}_{4,lt}, c \cdot \bar{\pi}_t, c \cdot \bar{\kappa}_{lt}\}$ is a feasible solution of (B.1), with the objective value of $c \cdot \bar{s}_t$. Thus the optimal objective value of (B.1) is not less than $c \cdot \bar{s}_t$, i.e.,

$$O \geq c \cdot \bar{s}_t \quad (\text{B.2})$$

Assume $\{\hat{\lambda}_{1,bt}, \hat{\lambda}_{2,bt}, b \in \mathbf{Z}^c, \bar{\lambda}_{1,bt}, \bar{\lambda}_{2,bt}, b \in \mathbf{Z}\}$ together with $\{\pi'_{1,pt}, \pi'_{2,pt}, \pi'_{3,lt}, \pi'_{4,lt}, \pi'_t, \kappa'_{lt}\}$ is the optimal solution of (B.1) with the optimal objective value of O . Thus it is obvious that $\{\hat{\lambda}_{1,bt}/c, \hat{\lambda}_{2,bt}/c, b \in \mathbf{Z}^c, \bar{\lambda}_{1,bt}/c, \bar{\lambda}_{2,bt}/c, b \in \mathbf{Z}\}$ together with $\{\pi'_{1,pt}/c, \pi'_{2,pt}/c, \pi'_{3,lt}/c, \pi'_{4,lt}/c, \pi'_t/c, \kappa'_{lt}/c\}$ is a feasible solution of (20) with the objective value of O/c . Since the optimal objective value to (20) is $\bar{s}_t$, we have

$$O/c \leq \bar{s}_t \quad (\text{B.3})$$

Using (B.2) and (B.3), we conclude that $O = c \cdot \bar{s}_t$. That is the optimal objective value of (B.1) O is equal to $c \cdot \bar{s}_t$. Comparing (B.1) with (19), the optimal solution of (19), which is $\hat{\lambda}_{1,bt}, \hat{\lambda}_{2,bt}$ for $b \in \mathbf{Z}^c$ and $\bar{\lambda}_{1,bt}, \bar{\lambda}_{2,bt}$ for $b \in \mathbf{Z}$ together with the corresponding $\{\pi'_{1,pt}, \pi'_{2,pt}, \pi'_{3,lt}, \pi'_{4,lt}, \pi'_t, \kappa'_{lt}\}$ is a feasible solution to (B.1) as this solution set satisfies all constraints in (B.1) with the objective value of $\hat{s}_t$. Thus, $\hat{s}_t$ is no larger than the optimal objective value $c \cdot \bar{s}_t$, that is $\hat{s}_t \leq c \cdot \bar{s}_t$. $\square$

Proof for Theorem 2 Suppose that contrary to our assumption, (21) is not pareto optimal. That is, there exists a cut (B.4) that dominates (21)

$$\sum_{b \in \mathbf{Z}^c} \sum_{i \in \mathbf{U}(b)} (\hat{\lambda}_{1,bt}/c - \hat{\lambda}_{2,bt}/c) \cdot (P_{it} - \hat{P}_{it}) + \sum_{b \in \mathbf{Z}} \sum_{i \in \mathbf{U}(b)} (\lambda'_{1,bt} - \lambda'_{2,bt}) \cdot P_{it} + \bar{s}_t \leq 0 \quad (\text{B.4})$$

Then from Definition 2, it is true that for all $\mathbf{P}_t$ in the domain of $\{\mathbf{0}, [\mathbf{P}^{\min}, \mathbf{P}^{\max}]\}$, we have

$$\left\{ \begin{aligned} & \left[\sum_{b \in \mathbf{Z}^c} \sum_{i \in \mathbf{U}(b)} (\hat{\lambda}_{1,bt}/c - \hat{\lambda}_{2,bt}/c) \cdot (P_{it} - \hat{P}_{it}) \right. \\ & \quad \left. + \sum_{b \in \mathbf{Z}} \sum_{i \in \mathbf{U}(b)} (\bar{\lambda}_{1,bt}/c - \bar{\lambda}_{2,bt}/c) \cdot P_{it} + \bar{s}_t \right] \\ & - \left[\sum_{b \in \mathbf{Z}^c} \sum_{i \in \mathbf{U}(b)} (\hat{\lambda}_{1,bt}/c - \hat{\lambda}_{2,bt}/c) \cdot (P_{it} - \hat{P}_{it}) \right. \\ & \quad \left. + \sum_{b \in \mathbf{Z}} \sum_{i \in \mathbf{U}(b)} (\lambda'_{1,bt} - \lambda'_{2,bt}) \cdot P_{it} + \bar{s}_t \right] \end{aligned} \right\} \leq 0 \quad (\text{B.5})$$

Thus (B.5) is true for $P_{it} = \hat{P}_{it}, \forall i \in \mathbf{U}(b), b \in \mathbf{Z}^c, P_{it} = P_i^{\max} - \varepsilon, \forall i \in \mathbf{U}(b), b \in \mathbf{SZ}_o$, and $P_{it} = (P_i^{\min} + \varepsilon), \forall i \in \mathbf{U}(b), b \in \{\mathbf{Z} - \mathbf{SZ}_o\}$, which indicates that

$$\left\{ \begin{aligned} & \left[\sum_{b \in \mathbf{SZ}_o} \sum_{i \in \mathbf{U}(b)} (\bar{\lambda}_{1,bt}/c - \bar{\lambda}_{2,bt}/c) \cdot (P_i^{\max} - \varepsilon) \right. \\ & \quad + \sum_{b \in \{\mathbf{Z} - \mathbf{SZ}_o\}} \sum_{i \in \mathbf{U}(b)} (\bar{\lambda}_{1,bt}/c - \bar{\lambda}_{2,bt}/c) \cdot (P_i^{\min} + \varepsilon) \\ & \quad - \left[\sum_{b \in \mathbf{SZ}_o} \sum_{i \in \mathbf{U}(b)} (\lambda'_{1,bt} - \lambda'_{2,bt}) \cdot (P_i^{\max} - \varepsilon) \right. \\ & \quad \left. \left. + \sum_{b \in \{\mathbf{Z} - \mathbf{SZ}_o\}} \sum_{i \in \mathbf{U}(b)} (\lambda'_{1,bt} - \lambda'_{2,bt}) \cdot (P_i^{\min} + \varepsilon) \right] \right] \end{aligned} \right\} \leq 0 \quad (\text{B.6})$$

With (B.4), $\{\hat{\lambda}_{1,bt}/c, \hat{\lambda}_{2,bt}/c, b \in \mathbf{Z}^c, \lambda'_{1,bt}, \lambda'_{2,bt}, b \in \mathbf{Z}\}$ together with $\{\pi'_{1,pt}, \pi'_{2,pt}, \pi'_{3,lt}, \pi'_{4,lt}, \pi'_{1,t}, \pi'_{2,t}\}$ is an optimal solution of (20) since its corresponding objective value is also $\hat{s}_t$. According to Theorem B.1, $\hat{s} \leq c \cdot \hat{s}_t$, thus there must exist a solution of $\{\hat{\lambda}_{1,bt}/c, \hat{\lambda}_{2,bt}/c, b \in \mathbf{Z}^c, \lambda'_{1,bt}, \lambda'_{2,bt}, b \in \mathbf{Z}\}$ together with $\{\pi''_{1,pt}, \pi''_{2,pt}, \pi''_{3,lt}, \pi''_{4,lt}, \pi''_{1,t}, \kappa''_{1,t}\}$ for (20), which has the objective value of $\hat{s}/c$. Thus $\{\hat{\lambda}_{1,bt}, \hat{\lambda}_{2,bt}, b \in \mathbf{Z}^c, c \cdot \lambda'_{1,bt}, c \cdot \lambda'_{2,bt}, b \in \mathbf{Z}\}$ together with $\{c \cdot \pi''_{1,pt}, c \cdot \pi''_{2,pt}, c \cdot \pi''_{3,lt}, c \cdot \pi''_{4,lt}, c \cdot \pi''_{1,t}, c \cdot \kappa''_{1,t}\}$ is a feasible solution of (19).

Since $\{\hat{\lambda}_{1,bt}, \hat{\lambda}_{2,bt}, b \in \mathbf{Z}^c, \bar{\lambda}_{1,bt}, \bar{\lambda}_{2,bt}, b \in \mathbf{Z}\}$ is the optimal solution of (19), and $\{\hat{\lambda}_{1,bt}, \hat{\lambda}_{2,bt}, b \in \mathbf{Z}^c, c \cdot \lambda'_{1,bt}, c \cdot \lambda'_{2,bt}, b \in \mathbf{Z}\}$ is one of its feasible solutions, we learn that

$$\left\{ \begin{aligned} & \left[\sum_{b \in \mathbf{SZ}_o} \sum_{i \in \mathbf{U}(b)} (\bar{\lambda}_{1,bt} - \bar{\lambda}_{2,bt}) \cdot (P_i^{\max} - \varepsilon) \right. \\ & \quad + \sum_{b \in \{\mathbf{Z} - \mathbf{SZ}_o\}} \sum_{i \in \mathbf{U}(b)} (\bar{\lambda}_{1,bt} - \bar{\lambda}_{2,bt}) \cdot (P_i^{\min} + \varepsilon) \\ & \quad - \left[\sum_{b \in \mathbf{SZ}_o} \sum_{i \in \mathbf{U}(b)} (c \cdot \lambda'_{1,bt} - c \cdot \lambda'_{2,bt}) \cdot (P_i^{\max} - \varepsilon) \right. \\ & \quad \left. \left. + \sum_{b \in \{\mathbf{Z} - \mathbf{SZ}_o\}} \sum_{i \in \mathbf{U}(b)} (c \cdot \lambda'_{1,bt} - c \cdot \lambda'_{2,bt}) \cdot (P_i^{\min} + \varepsilon) \right] \right] \end{aligned} \right\} \geq 0 \quad (\text{B.7})$$

Multiplying both sides of (B.7) by c , we get (B.8) where $c = \sum_{b \in \mathbf{NZ}} (-\hat{\lambda}_{1,bt} - \hat{\lambda}_{2,bt}) + 2 \cdot |\mathbf{Z}|$ is a positive constant

$$\left\{ \begin{aligned} & \left[\sum_{b \in \mathbf{SZ}_o} \sum_{i \in \mathbf{U}(b)} (\bar{\lambda}_{1,bt}/c - \bar{\lambda}_{2,bt}/c) \cdot (P_i^{\max} - \varepsilon) \right. \\ & \quad + \sum_{b \in \{\mathbf{Z} - \mathbf{SZ}_o\}} \sum_{i \in \mathbf{U}(b)} (\bar{\lambda}_{1,bt}/c - \bar{\lambda}_{2,bt}/c) \cdot (P_i^{\min} + \varepsilon) \\ & \quad - \left[\sum_{b \in \mathbf{SZ}_o} \sum_{i \in \mathbf{U}(b)} (\lambda'_{1,bt} - \lambda'_{2,bt}) \cdot (P_i^{\max} - \varepsilon) \right. \\ & \quad \left. \left. + \sum_{b \in \{\mathbf{Z} - \mathbf{SZ}_o\}} \sum_{i \in \mathbf{U}(b)} (\lambda'_{1,bt} - \lambda'_{2,bt}) \cdot (P_i^{\min} + \varepsilon) \right] \right] \end{aligned} \right\} \geq 0 \quad (\text{B.8})$$

Using (B.6) and (B.8), we have

$$\left\{ \begin{aligned} & \left[\sum_{b \in \mathbf{SZ}_o} \sum_{i \in \mathbf{U}(b)} (\bar{\lambda}_{1,bt}/c - \bar{\lambda}_{2,bt}/c) \cdot (P_i^{\max} - \varepsilon) \right. \\ & \quad + \sum_{b \in \{\mathbf{Z} - \mathbf{SZ}_o\}} \sum_{i \in \mathbf{U}(b)} (\bar{\lambda}_{1,bt}/c - \bar{\lambda}_{2,bt}/c) \cdot (P_i^{\min} + \varepsilon) \\ & \quad - \left[\sum_{b \in \mathbf{SZ}_o} \sum_{i \in \mathbf{U}(b)} (\lambda'_{1,bt} - \lambda'_{2,bt}) \cdot (P_i^{\max} - \varepsilon) \right. \\ & \quad \left. \left. + \sum_{b \in \{\mathbf{Z} - \mathbf{SZ}_o\}} \sum_{i \in \mathbf{U}(b)} (\lambda'_{1,bt} - \lambda'_{2,bt}) \cdot (P_i^{\min} + \varepsilon) \right] \right] \end{aligned} \right\} = 0 \quad (\text{B.9})$$

Since (B.4) dominates (21), according to the Definition 1 there must exists a $\tilde{\mathbf{P}}$ in the domain of $\{\mathbf{0}, [\mathbf{P}^{\min}, \mathbf{P}^{\max}]\}$ which satisfies the strict inequality of (B.5) as shown in (B.10)

$$\left\{ \begin{aligned} & \left[\sum_{b \in \mathbf{Z}^c} \sum_{i \in \mathbf{U}(b)} (\hat{\lambda}_{1,bt}/c - \hat{\lambda}_{2,bt}/c) \cdot (\tilde{P}_i - \hat{P}_{it}) \right. \\ & \quad + \sum_{b \in \mathbf{Z}} \sum_{i \in \mathbf{U}(b)} (\bar{\lambda}_{1,bt}/c - \bar{\lambda}_{2,bt}/c) \cdot \tilde{P}_i + \tilde{s}_t \\ & \quad - \left[\sum_{b \in \mathbf{Z}^c} \sum_{i \in \mathbf{U}(b)} (\hat{\lambda}_{1,bt}/c - \hat{\lambda}_{2,bt}/c) \cdot (\tilde{P}_i - \hat{P}_{it}) \right. \\ & \quad \left. \left. + \sum_{b \in \mathbf{Z}} \sum_{i \in \mathbf{U}(b)} (\lambda'_{1,bt} - \lambda'_{2,bt}) \cdot \tilde{P}_i + \tilde{s}_t \right] \right] \end{aligned} \right\} < 0 \quad (\text{B.10})$$

Applying $\tilde{\mathbf{P}}$ to (B.9), we get

$$\left\{ \begin{aligned} & \left[\sum_{b \in \mathbf{Z}^c} \sum_{i \in \mathbf{U}(b)} (\hat{\lambda}_{1,bt}/c - \hat{\lambda}_{2,bt}/c) \cdot (\tilde{P}_i - \hat{P}_{it}) \right. \\ & \quad + \sum_{b \in \mathbf{SZ}_o} \sum_{i \in \mathbf{U}(b)} (\bar{\lambda}_{1,bt}/c - \bar{\lambda}_{2,bt}/c) \cdot (P_i^{\max} - \varepsilon) \\ & \quad + \sum_{b \in \{\mathbf{Z} - \mathbf{SZ}_o\}} \sum_{i \in \mathbf{U}(b)} (\bar{\lambda}_{1,bt}/c - \bar{\lambda}_{2,bt}/c) \cdot (P_i^{\min} + \varepsilon) \\ & \quad - \left[\sum_{b \in \mathbf{Z}^c} \sum_{i \in \mathbf{U}(b)} (\hat{\lambda}_{1,bt}/c - \hat{\lambda}_{2,bt}/c) \cdot (\tilde{P}_i - \hat{P}_{it}) \right. \\ & \quad + \sum_{b \in \mathbf{SZ}_o} \sum_{i \in \mathbf{U}(b)} (\lambda'_{1,bt} - \lambda'_{2,bt}) \cdot (P_i^{\max} - \varepsilon) \\ & \quad \left. \left. + \sum_{b \in \{\mathbf{Z} - \mathbf{SZ}_o\}} \sum_{i \in \mathbf{U}(b)} (\lambda'_{1,bt} - \lambda'_{2,bt}) \cdot (P_i^{\min} + \varepsilon) \right] \right] \end{aligned} \right\} = 0 \quad (\text{B.11})$$

Theorem 1 points out that there exists a scalar $\theta > 1$ such that $\theta \cdot (P_i^{\max} - \varepsilon) + (1 - \theta) \cdot \tilde{P}_i$ and $\theta \cdot (P_i^{\min} + \varepsilon) + (1 - \theta) \cdot \tilde{P}_i$ are in the range of $\{\mathbf{0}, [\mathbf{P}^{\min}, \mathbf{P}^{\max}]\}$. Thus multiplying (B.11) by θ and (B.10) by $(1 - \theta)$ which is negative and preserves the inequality,

and adding the two quantities up, we get

$$\begin{aligned}
 & \sum_{b \in \mathbf{Z}^c} \sum_{i \in \mathbf{U}(b)} (\hat{\lambda}_{1,bt}/c - \hat{\lambda}_{2,bt}/c) \cdot (\tilde{P}_i - \hat{P}_{it}) \\
 & + \sum_{b \in \mathbf{SZ}_o} \sum_{i \in \mathbf{U}(b)} (\bar{\lambda}_{1,bt}/c - \bar{\lambda}_{2,bt}/c) \cdot [\theta \cdot (P_i^{\max} - \varepsilon) + (1 - \theta) \cdot \tilde{P}_i] \\
 & + \sum_{b \in \{\mathbf{Z} - \mathbf{SZ}_o\}} \sum_{i \in \mathbf{U}(b)} (\bar{\lambda}_{1,bt}/c - \bar{\lambda}_{2,bt}/c) \cdot [\theta \cdot (P_i^{\min} + \varepsilon) + (1 - \theta) \cdot \tilde{P}_i] \\
 & > \sum_{b \in \mathbf{Z}^c} \sum_{i \in \mathbf{U}(b)} (\hat{\lambda}_{1,bt}/c - \hat{\lambda}_{2,bt}/c) \cdot (\tilde{P}_i - \hat{P}_{it}) \\
 & + \sum_{b \in \mathbf{SZ}_o} \sum_{i \in \mathbf{U}(b)} (\lambda'_{1,bt} - \lambda'_{2,bt}) \cdot [\theta \cdot (P_i^{\max} - \varepsilon) + (1 - \theta) \cdot \tilde{P}_i] \\
 & + \sum_{b \in \{\mathbf{Z} - \mathbf{SZ}_o\}} \sum_{i \in \mathbf{U}(b)} (\lambda'_{1,bt} - \lambda'_{2,bt}) \cdot [\theta \cdot (P_i^{\min} + \varepsilon) + (1 - \theta) \cdot \tilde{P}_i] \quad (\text{B.12})
 \end{aligned}$$

Equation (B.12) indicates that

$$P_{it} = \begin{cases} \tilde{P}_i & \forall i \in \mathbf{U}(b), b \in \mathbf{Z}^c \\ \theta \cdot (P_i^{\max} - \varepsilon) + (1 - \theta) \cdot \tilde{P}_i, & \forall i \in \mathbf{U}(b), b \in \mathbf{SZ}_o \\ \theta \cdot (P_i^{\min} + \varepsilon) + (1 - \theta) \cdot \tilde{P}_i, & \forall i \in \mathbf{U}(b), b \in \{\mathbf{Z} - \mathbf{SZ}_o\} \end{cases}$$

then

$$\left\{ \begin{aligned} & \left[\sum_{b \in \mathbf{Z}^c} \sum_{i \in \mathbf{U}(b)} (\hat{\lambda}_{1,bt}/c - \hat{\lambda}_{2,bt}/c) \cdot (P_{it} - \hat{P}_{it}) \right. \\ & \quad \left. + \sum_{b \in \mathbf{Z}} \sum_{i \in \mathbf{U}(b)} (\bar{\lambda}_{1,bt}/c - \bar{\lambda}_{2,bt}/c) \cdot P_{it} + \tilde{s}_t \right] \\ & - \left[\sum_{b \in \mathbf{Z}^c} \sum_{i \in \mathbf{U}(b)} (\hat{\lambda}_{1,bt}/c - \hat{\lambda}_{2,bt}/c) \cdot (P_{it} - \hat{P}_{it}) \right. \\ & \quad \left. + \sum_{b \in \mathbf{Z}} \sum_{i \in \mathbf{U}(b)} (\lambda'_{1,bt} - \lambda'_{2,bt}) \cdot P_{it} + \tilde{s}_t \right] \end{aligned} \right\} > 0$$

which is inconsistent with (B.5) and shows that our assumption that (21) is not pareto optimal is untenable. Thus (21) is pareto optimal. $\square$

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Extended Benders Decomposition for Two-Stage SCUC

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Abstract—This paper presents the solution of a two-stage security-constrained unit commitment (SCUC) problem. The proposed SCUC model could include integer variables at the second stage. A framework of extended Benders decomposition with linear feasibility and optimality cuts is proposed for the solution of mixed-integer programming (MIP) problems at both stages. Test results show the effectiveness of the proposed methodology.

Index Terms— SCUC, MIP, L-shaped decomposition.

I. NOMENCLATURE

A, b, c, d, E, F, g	Coefficients vector, matrix of MIP problem
e, I	Vector of ones and identity matrix
i, j, k, s	Index of nodes in branch and bound trees, iterations and scenarios
m_1, n_1, m_2, n_2	Dimension of first/second stage problems
$O(\cdot), IF(\cdot), Q(\cdot)$	Dual price function of MIP problem
$OR(\cdot), IFR(\cdot)$	Dual price function of LP-Relaxation of MIP
S, p^s	Number of scenarios and their probabilities
t, x, y	First stage, second stage and slack variables
X, Y	Spanning space of x and y variables
z, θ	Variables represent objective function values
$\delta_{OR}, \delta_{IFR}$	Ancillary binary variables
μ, π	Dual variables
ε, M	Predefined tolerance and a large number

II. PROPOSED MIP PROBLEM

The SCUC problem shown in Table I is solved in two stages according to its specific structure. Generally, the first stage corresponds to an optimal decision, while the second stage would examine the viability of first stage decisions.

TABLE I SCUC DECOMPOSITION STRATEGIES

Problem	First Stage	Second Stage
UC with network constraints	UC	Transmission constraints
Contingency-based SCUC	UC with pre-contingency transmission constraints	Post-contingency transmission constraints
Two-stage stochastic SCUC	Decision costs and constraints	Recourse costs and constraints

Benders cut applications are based on a prerequisite that the subproblem corresponding to the second stage is LP or convex NLP [1]. In practice, variables in the second stage can be integer or semi-continuous. Consider the following examples:

1. Integer variables in power transmission control.
2. Status of quick start units in post-contingency evaluation.

We have developed an extended Benders decomposition method which can be applied to such SCUC problems. The SCUC problem is represented as a MIP formulation (1)-(4). Decision variables x at the first stage and y at the second

stage in P could be either integer or continuous. The constraint structure is L-shaped and no coupling among subproblems.

$$P: \quad \text{Min } z = \left\{ c \cdot x + \sum_s p^s \cdot d^s \cdot y^s \right\} \quad (1)$$

$$s.t. \quad A \cdot x \geq b \quad (2)$$

$$E^s \cdot x + F^s \cdot y^s \geq g^s \quad \forall s \in \{1, 2, \dots, S\} \quad (3)$$

$$x \in X = \text{span} \left\{ R^{m_1} \times \{0, 1\}^{n_1} \right\}, y^s \in Y = \text{span} \left\{ R^{m_2} \times \{0, 1\}^{n_2} \right\} \quad (4)$$

Nonlinear feasibility and optimality cuts were developed in [3] via the general duality theory and showed that an L-shaped decomposition can converge within a finite time. The formulation of optimality and feasibility cuts are given in (12)-(13). After introducing integer variables, the linear feasibility and optimality cuts (21)-(23) would transform the two-stage SCUC problem into a MIP set, which can be incorporated into the master problem and lead to the global optimal solution.

As to the extended Benders decomposition, the mixed-integer master problem (BD-MP) and subproblems (BD-SP) are given in (5)-(8) and (9), respectively.

$$\text{BD-MP: } z_{LB} = \text{Min}_{x, \theta^s} \left\{ c \cdot x + \sum_s p^s \cdot \theta^s \right\} \quad (5)$$

$$s.t. \quad A \cdot x \geq b \quad x \in X, \quad \theta^s \in R^1 \quad (6)$$

$$O^s(x) - \theta^s \leq 0 \quad (7)$$

$$IF^s(x) \leq 0 \quad (8)$$

$$\text{BD-SP: } \text{Min}_y \left\{ d^s \cdot y^s \mid F^s \cdot y^s \geq g^s - E^s \cdot \hat{x}, y^s \in Y \right\} \quad (9)$$

Here, $\hat{x}$ is the current BD-MP solution. In addition, (7)-(8) represent optimality and feasibility cuts, respectively, which are formed by solving BD-SP. The BD-MP solution provides a lower bound while a feasible BD-SP solution leads to an upper bound. The optimal solution of P is calculated when upper and lower bounds are sufficiently close according to (10),

$$(z_{UB} - z_{LB}) / z_{UB} \leq \varepsilon \quad (10)$$

We form feasibility and optimality cuts by the dual price function when BD-SP is a MIP problem. BD-SP is nonconvex so its dual problem (BD-DSP) is given in (11) which is based on the general duality theory:

$$\text{Max}_{Q^s, \theta^s} \left\{ Q^s(g^s - E^s \cdot \hat{x}) \mid Q^s(F^s \cdot y^s) \leq d^s \cdot y^s, \forall y^s \in Y \right\} \quad (11)$$

This problem is considered as finding MIP sensitivities of (9) corresponding to the right-hand side of $(g^s - E^s \cdot \hat{x})$. According to [2], a lower bound at a non-terminal node, which is based on branch and bound, is proposed in (12),

$$O_i^s(x) = \text{Max} \left\{ OR_i^s(x), \text{Min} \left\{ O_{i, LB}^s(x), O_{i, UB}^s(x) \right\} \right\} \quad (12)$$

where $OR_i^s(x)$ is the dual price function of the LP-relaxation of MIP (9) at the current node i . $O_{i, LB}^s(x)$, $O_{i, UB}^s(x)$ are dual

price functions of lower and upper partition nodes of current i . If the relaxed LP at current node is infeasible, $OR_i^s(x) = +\infty$ is set and the feasibility cut (13) is added,

$$IFR_i^s(x) \leq 0 \quad (13)$$

If the current node is a root node of branch and bound tree, the optimality cuts and feasibility cuts based on (12) and (13) are fed back to BD-MP. Reference [2] offers another dual price function (14) where node i belongs to the set of feasible terminal nodes in the tree generated by branch and bound. Coefficients in (15) are determined by solving the LP primal-dual problem (16)-(18)

$$O^s(x) = \min_i \{OR_i^s(x) \mid i \in \text{set of feasible terminal nodes}\} \quad (14)$$

$$OR_i^s(x) = \mu_i^s \cdot (g^s - E^s \cdot x) + \bar{\pi}_i^s \cdot \bar{y}^s + \underline{\pi}_i^s \cdot \underline{y}^s \quad (15)$$

$$\min d^s \cdot y^s \quad (16)$$

$$s.t. \quad F^s \cdot y^s \geq g^s - E^s \cdot \hat{x} \quad \mu_i^s \geq 0 \quad (17)$$

$$\bar{y}_i^s \geq y_i^s \geq \underline{y}_i^s \quad \bar{\pi}_i^s \leq 0, \underline{\pi}_i^s \geq 0 \quad (18)$$

If a terminal node j of a BD-SP scenario is infeasible, we add a slack vector to the LP (19) corresponding to the terminal node. We form feasibility cuts (20) the same way as optimality cuts by finding the dual price function of (19). Compared to (12), the combination of (14) and (20) is a weaker bound which leads to a global optimal solution within a finite time [3].

$$\min_{t^s, y^s} \{e^s \cdot t^s \mid F^s \cdot y^s + I^s \cdot t^s \geq g^s - E^s \cdot \hat{x}, \bar{y}_j^s \geq y_j^s \geq \underline{y}_j^s\} \quad (19)$$

$$IF^s(x) = \min_j \{IFR_j^s(x) \mid j \in \text{set of infeasible terminal nodes}\} \quad (20)$$

Substituting (14) and (20) into (7) and (8), respectively, the BD-MP becomes a mixed-integer bilevel optimization problem. We introduce additional integer variables δ in the BD-SP so that (21)-(23) can be used instead of (7)-(8).

$$OR_i^s(x) - \theta^s - (1 - \delta_i^s) \cdot M \leq 0 \quad i \in \text{set of feasible terminal nodes} \quad (21)$$

$$IFR_j^s(x) - (1 - \delta_j^s) \cdot M \leq 0 \quad j \in \text{set of infeasible terminal nodes} \quad (22)$$

$$\sum_i \delta_i^s + \sum_j \delta_j^s = 1 \quad \delta_i^s, \delta_j^s \in \{0,1\} \quad (23)$$

The decomposition solution in Fig. 1 is summarized as follows:

Fig. 1. Decomposition framework

Step 0: Set the lower bound $z_{LB} = 0$, $z_{UB} = +\infty$. Initialize the iteration counter of outer loop $k = 1$ and tolerance ε .

Step 1: Introduce (21)-(23) instead of (7) and (8) for Benders cuts and solve the MIP-based BD-MP.

Step 2: Go to Step 2.1 if BD-SPs are feasible for all scenarios, based on the solution of BD-MP. Otherwise, go to Step 2.2.

Step 2.1: For each scenario, form an optimality cut (7) by branch and bound. Update z_{UB} . If (10) is satisfied, stop the procedure. Else, go to Step 1 and set $k = k + 1$.

Step 2.2: For infeasible scenarios, use branch and bound to

form feasibility cuts (8). Go to Step 1 and set $k = k + 1$.

III. NUMERICAL EXAMPLE

Three generators are scheduled by a two-stage stochastic UC to supply a load with uncertainty levels shown in Table II. Unit 1 is a coal unit without a quick start capacity; thus its commitment decision can only be made at the first stage. However, units 2 and 3 have quick start capability and their commitment can be adjusted quickly at the second stage. The second stage is comprised of two parallel MIP subproblems corresponding to two scenarios with commitment decisions for units 2 and 3. The problem is solved by applying the proposed extended Benders decomposition. Table II shows the second-stage solution of the stochastic UC by the proposed method, which is the same as that of solving the MIP problem without decomposition by applying CPLEX. The first stage solution shows that unit 1 is committed in both scenarios. The second stage solution shows that Unit 2 is committed only at hour 2 in scenario 1. Two iterations between BD-MP and BD-SP are executed, and two feasibility cuts (21) and two optimality cuts (22) are generated before (10) is satisfied. More information on this example is presented in http://motor.ece.iit.edu/data/bds_example.doc.

TABLE II SECOND-STAGE STOCHASTIC UC SOLUTION (MW)

Scenario	Probability	Period	Load	Unit 1	Unit 2	Unit 3
1	0.5	T=1	90	90	0	0
		T=2	110	100	10	0
2	0.5	T=1	95	95	0	0
		T=2	105	100	0	0

IV. DISCUSSIONS AND SUMMARY

The SCUC problem is solved by introducing the decomposition presented in Table I for practical systems with a large number of scenarios/contingencies. The deterministic SCUC problems in Table I, which require no optimality cuts, can be solved by a limited number of feasibility cuts. With $N1$ quick-start units, S contingencies, and $N2$ discrete network equipment, the number of the second-stage integer variables is $S*(N1+N2)$, which could be a large number and make it impossible to solve the problem without decomposition. In the proposed method, the number of feasibility cuts (22) is much less than $S*(N1+N2)$ which can be solved easily for large systems. The stochastic SCUC in Table I, which considers recourse costs, would require optimality and feasibility cuts formed in every scenario. For a global optimization, $2^{(N1+N2)*S}$ integer variables would be introduced into the master problem as shown in (21)-(23). The type 1 Special Ordered Set (23) facilitates the branching process of branch-and-bound method for a faster convergence. The potential future studies could seek better methodologies for implementing (12), (13), (14) and (20) such that a few terminal nodes in the tree can be excluded in (14) and (20). Heuristic algorithms may be embedded into the proposed framework to provide a tradeoff between the computing time and the accuracy.

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Capacity Adequacy Calculation by Considering Locational Capacity Prices

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ABSTRACT

A proper investment mechanism is required in restructured power systems to secure the adequacy of installed capacity by encouraging investments on generation and transmission expansions. In this paper, we propose a locational capacity price (LCP) model along with multi-level load bidding curves, which reflect the effectiveness of the market-based capacity payment and at the same time, prohibits the capacity withholding and the exercising of market power. The purpose of capacity expansion decision is analyzed and compared with three other market design options, i.e., energy only, capacity payment, and installed capacity. The case studies show that the proposed LCP method provides proper investment signals in capacity-constrained locations. The proposed LCP method also provides signals to system operators to alleviate transmission congestions economically using proper operation strategies in power systems.

1. NOMENCLATURE

The symbols used in this paper are classified into indices, parameters, variables and Matrices and Vectors as follows.

Indices:

$\max$	Subscript index for upper bound
$\min$	Subscript index for lower bound
g	Subscript for GENCO
$*$	Superscript for optimal value

Parameters:

CUR	Capacity usage rate
$E[\cdot]$	Expected value
FOR	Forced outage rate
$F(V)$	Value of postponed investment
I	Investment cost
LMP	Locational marginal price
$Load_{lij,t}$	Forecasted bidding quantity of the load l at segment i and alternative j at time t
L_{peak}	Peak load
lft	Expected life time of the project
N_g	Number of generator's bidding segments
NS_{lt}	Number of bidding segments of load l at time t
NA_{lit}	Number of alternatives at the bidding segment i of load l at time t
OC	Average operating cost
$P_{g,t}$	Dispatched power of generator g at time t
Pr_t	Generator profit function

T	Investment time parameter
wf	Weighting Factor
α	Project value factor
ρ	Discount rate
θ	Bus angel
$\lambda, \kappa, \pi, \mu$	Lagrangian multipliers

Variable:

t	Planning time variable
$L_{ij,t}$	Accepted load quantity at the bidding segment i and alternative j at time t
V	Value of the project
$U_{ij,t}$	Load quantity binary integer variable at the bidding segment i and alternative j at time t ; equal to 1 when the load bid is accepted and 0 when the bid is not accepted by the market

Matrices and Vectors:

A	Bus-unit incidence matrix
B	Bus-load incidence matrix
b	Bidding price vector of buyers
c	Bidding price vector of buyers
H	Bus-angel incidence matrix
K	Bus-branch incidence matrix
P	Bidding energy vector of sellers
P_D	Bidding energy vector of buyers
PL	Real power flow in vector form
X	Line reactance vector

2. INTRODUCTION

Adequacy analyses would investigate the ability of power systems to provide a reliable supply of energy [1,2]. In theory, the capacity adequacy is managed by market participants in a perfectly competitive market with provisions for the allocation of risks to consumers and suppliers [2]. However, the California market crisis showed that the market alone may not produce sufficient investment signals to guarantee the capacity adequacy. The main reasons which impede electricity markets from generating such investment signals include, but may not be limited to, flaws in the demand response, market power, excessive investment risks, and ill-designed capacity markets [2,3]. An exertion of market power is made possible by monitoring the gap between the marginal cost and real market prices [4,5]. Insufficient energy market revenues to compensate capacity investments resulted in other market mechanisms, which included “installed capacity” (ICAP) and capacity payment (CP) [2]. ICAP deficiencies would include a lack of representation of locational- or temporal-based market prices. Furthermore, ICAP could provide a revenue source for generating units that are seldom committed or have only contributed to generation supply in peak periods. Such units may submit bids that are as high as price caps so that they do not participate in energy supply and get paid by ICAP [3,6]. The CP mechanism may encourage market participants to exercise market power as insecure markets would tend to supply more CPs, i.e. capacity payments could be the same as the value of lost load (VOLL) (i.e., market price cap) times a reliability index (e.g., loss of load probability). So generators would find it more profitable to pose artificial capacity deficiencies. In recent years, US electricity markets have reformed the capacity adequacy calculation mechanisms, which include the PJM’s reliability pricing model (RPM), the ISO-NE’s locational installed capacity (LICAP) model, and the demand curve model considered in NYISO and MISO [7,8]. There are other approaches to the capacity market, e.g., call option [9,10] and capacity subscription [11,12], which are not widely

implemented in electricity markets.

Our previous studies on the system capacity expansion [13-15] showed that a market-based signal would ensure sufficient and optimal investments in generation and transmission. Market mechanisms for the capacity adequacy were compared in [7] and concluded that a capacity mechanism is needed for resource adequacy, both in power pools and in transmission-constrained regions. Studies on energy only market models for supplying an adequate capacity concluded that a greater transparency into market behaviors, supply and demand forecasts, and higher system-wide offer caps is needed to ensure the market success [16]. It also discussed that low price cap could result in under-investment in generation capacity [17]. Resource adequacy is a critical part of the reliability when demand response is insufficient or non-existent. Resource adequacy problems in several existing power markets were thoroughly discussed in [18]. In the literature, resource adequacy is classified into two main categories including short-term and long-term problems. Different aspect of the short-term capacity adequacy was elaborated in [19-21] and the long-term capacity mechanism was addressed in [22-24]. Another study showed that generation investment decisions could be evaluated based on the real options theory [24]. The real options theory presents new alternatives in investment strategies since it considers market uncertainties and options to invest when evaluating the value of project delays [26,27].

In this paper, we utilize the real options theory for the modeling of investments under uncertainties. Such uncertainties include financial and physical risks pertaining to the time and the location of new capacity expansions. The proposed method compares net cash flows in two possible investment modes: 1) invest right after net present value (*NPV*) of the project becomes positive (instant decision), and 2) consider a delay in investment to achieve the maximum profit (postponed decision). The rest of this paper is organized as follows. Section 3 discusses real options theory and its application in capacity expansion problem. Section 4 presents the proposed methodology and mathematical formulation. Section 5 in detail discusses the effectiveness of proposed approach in a sample two-bus system with three units and IEEE 118-bus system with 54 units. Section 6 provides the conclusions drawn from the proposed studies.

3. INVESTMENT IN CAPACITY WITH UNCERTAINTY

The capacity expansion mechanism introduces optimal the size, location, algorithm, and time for new investments in power generation. Capacity investors consider the time for the implementation of new projects, a flexible item as compared to other decision attributes. Therefore, we consider the investment time as a decision variable. We assume that the investment cost, I , is given. The finance theory indicates that the *NPV* is the best measure for evaluating new investments, which signals to invest as long as the V is larger than the discounted I , i.e., the sum of discounted cash flows from the project is positive. However, this would lead to an incorrect result because the static *NPV* assessment does not consider the choice of deferring the investment. While future values of V are unknown, there is always an opportunity cost for investing today. Hence, the optimal investment rule is stated as make the investment when V is larger than a critical value V^* [26-28]. The value of investment opportunity, $F(V)$, in dollars is given as in (1), where V is the value of the project and a function of the planning time variable, t . On the other hand, the planning period includes the investment time and the lifetime of installed unit.

$$F(V) = \max_t E[(V - I) \cdot \exp(-\rho t)] \quad (1)$$

where,

$$V = V_0 \exp(\alpha t) \quad (2)$$

$$\text{and } V_0 = \frac{V}{(1 + \rho)^t} \quad (3)$$

Using (2) and (3), we obtain α as

$$\alpha = \ln(1 + \rho) \quad (4)$$

in which $0 < \alpha < \rho$. In a deterministic model, the expectation function give in (1) would be eliminated. Therefore to maximize $F(V)$ with respect to t in (1), the first order condition would be

$$\frac{dF(V)}{dt} = -(\rho - \alpha)V_0 \exp(-(\rho - \alpha)t) + \rho I \exp(-\rho t) = 0 \quad (5)$$

where $0 \leq t \leq T + lft$; which implies that the optimal investment time is

$$T^* = \max \left\{ \frac{1}{\alpha} \ln \left[\frac{\rho I}{(\rho - \alpha)V} \right], 0 \right\} \quad (6)$$

Accordingly, the decision to invest is made readily if V is sufficiently larger than I ; otherwise $T^* > 0$ denotes the optimal investment time. The value of V^* , which corresponds to an immediate investment, is obtained by setting $T^* = 0$ in (4). So,

$$V^* = \frac{\rho I}{(\rho - \alpha)} > I \quad (7)$$

Finally, by substituting (6) in (1), we obtain,

$$F(V) = \begin{cases} [\alpha I / (\rho - \alpha)] \{(\rho - \alpha)V_0 / \rho I\}^{\rho/\alpha} & V \leq V^* \\ V - I & V \geq V^* \end{cases} \quad (8)$$

and the NPV of the project, $N(V)$, is obtained as

$$N(V) = -\frac{I}{(1 + \rho)^T} + \sum_{t=T}^{T+lft} \frac{V}{(1 + \rho)^t} \quad (9)$$

The planning period, t , starts from the initial point of study and finishes at the end of the project lifetime. However, only a certain time in the planning period, t , is candidate for investment, T .

It is shown in Fig. 1, that the optimal investment time (6) is the intersection of (8) and (9). The intersection of $F(V)$ and $N(V)$ in Fig. 1 would determine V^* (or equivalently T^*), which is the optimal value and the time of the investment. In the following, we discuss the optimal investment and the time for capacity expansion.

Figure 1 Optimal investment time and value based on the real options theory

4. PROPOSED CAPACITY MECHANISM AND FORMULATION

In order to determine the optimal investment threshold, the market is simulated while the load is progressively increased during the lifetime of the installed generation unit. Here, we calculate the discounted project value (NPV) and determine the value of deferring the investment (forwarding value). The static NPV rule recommends that investors proceed with the project when $N(V)$ turns positive. However, we consider a more restrictive investment strategy by considering the option to wait for maximizing the profit and minimizing the risk. Fig. 2 shows the proposed capacity investment decision process using the real options theory. The flowchart simulates the market for the entire planning period (t). $N(V)$ is calculated in each year for the expected lifetime of generation unit and compared to $F(V)$. The optimal investment time occurs when $N(V)$ exceeds $F(V)$. If $N(V)$ is higher than $F(V)$ at the starting point, the investment decision can be made immediately. However, if the two curves do not intersect, the investment will not be profitable.

Figure 2 Capacity expansion procedure using the real options theory

The market-clearing model in Fig. 2 could represent energy only, installed capacity, capacity payment, or the proposed locational capacity price approach. Regardless of the market mechanism, the objective is to maximize the

social welfare (10) based on the prevailing power flow constraints including power balance (11), dc power flow (12), line flow limits (13), generation limits (14), demand range (15) and the reference bus angel constraint (16) [29].

$$\text{Max } \mathbf{b}^T \mathbf{P}_D - \mathbf{c}^T \mathbf{P} \quad (10)$$

S.t.

$$\mathbf{K} \cdot \mathbf{PL} - \mathbf{A} \cdot \mathbf{P} + \mathbf{B} \cdot \mathbf{P}_D = \mathbf{0} \quad \lambda \quad (11)$$

$$\mathbf{PL} = \mathbf{X}^{-1} \mathbf{K}^T \boldsymbol{\theta} \quad \kappa \quad (12)$$

$$-\mathbf{PL}_{\max} \leq \mathbf{PL} \leq \mathbf{PL}_{\max} \quad \underline{\pi}, \bar{\pi} \quad (13)$$

$$\mathbf{P}_{\min} \leq \mathbf{P} \leq \mathbf{P}_{\max} \quad \underline{\mu}_P, \bar{\mu}_P \quad (14)$$

$$\mathbf{P}_{D\min} \leq \mathbf{P}_D \leq \mathbf{P}_{D\max} \quad \underline{\mu}_L, \bar{\mu}_L \quad (15)$$

$$\theta_{ref} = 0 \quad \mu_{ref} \quad (16)$$

The generator revenue depends on the market structure and operation. We simulate the capacity expansion process using four models, including energy only, installed capacity, capacity payment, and locational capacity price. We compare the corresponding investment efficiencies including the value and the time of project investment. The bus LCP is a positive (or zero) value which is obtained from the base generator's maximum power capacity at a given bus. The base generator at a bus is the one with the lowest bidding price and the highest capacity usage rate. The capacity usage rate is given as

$$CUR_{gt} = \frac{P_{gt}}{P_{g,\max}} \quad (17)$$

Using (10)-(16), the Lagrange function is

$$\begin{aligned} L = & \mathbf{c}^T \mathbf{P} - \mathbf{b}^T \mathbf{L} + \lambda^T (\mathbf{K} \cdot \mathbf{PL} - \mathbf{A} \cdot \mathbf{P} + \mathbf{B} \cdot \mathbf{L}) + \kappa^T (\mathbf{PL} - \mathbf{X}^{-1} \mathbf{H}^T \boldsymbol{\theta}) + \bar{\pi}^T (\mathbf{PL} - \mathbf{PL}_{\max}) + \underline{\pi}^T (-\mathbf{PL}_{\max} - \mathbf{PL}) \\ & - T \\ & + \bar{\mu}_P (\mathbf{P} - \mathbf{P}_{\max} - \Delta \mathbf{P}_{\max}) + \underline{\mu}_P (\mathbf{P}_{\min} - \mathbf{P}) + \underline{\mu}_L (\mathbf{L} - \mathbf{L}_{\max}) + \underline{\mu}_L^T (\mathbf{L}_{\min} - \mathbf{L}) + \mu_{ref} \theta_{ref} \end{aligned} \quad (18)$$

The bus LCP, which is the shadow capacity price of the base generator, is given as

$$LCP = -\frac{\partial F}{\partial \Delta \mathbf{P}_{\max}} = \bar{\mu}_P \quad (19)$$

Figure 3 Generators' bidding price and change in the social welfare

The rationale for using LCP as a capacity signal is that by increasing the number of fully-loaded units in a bus, the

Lagrange multiplier corresponding to the base generator's capacity constraint will increase. Assume that bids of N_g generators are $C_1, C_2, \dots, C_{N_g-i}, \dots, C_{N_g}$ where $C_1 < C_2 < \dots < C_{N_g-i} < \dots < C_{N_g}$. By disregarding the operating constraints and assuming that the generation units bid at their maximum capacity, when N_g generators are in service, at least (N_g-1) generators are at their capacity and only the most expensive generator may be loaded partially. So by adding one MW to the capacity of generator 1, P_{N_g} will decrease by one MW and P_1 will increase by one MW. Accordingly, the change in social welfare will be $(C_{N_g} - C_1)$. Hence, the change in the social welfare ($\bar{\mu}_P = \text{LCP}$) is larger when there are N_g generators as compared to (N_g-i) , i.e. $(C_{N_g} - C_1) > (C_{N_g-i} - C_1)$. Hence, LCP is a capacity signal. The higher the LCP, the more capacity constrained the system will be at a bus, which encourages a capacity investment to relieve capacity scarcity. The generators' bidding value and the changes in social welfare for each mode are shown in Fig. 3.

In the locational capacity model, generators would have income for selling electricity at LMP in addition to earning revenues equal to the LCP times the available capacity (20).

$$\text{Pr}_{gt} = \sum_{t=T}^{T+1ft} [(LMP_t - OC_{gt}) \cdot P_{gt} + wf \cdot LCP_t \cdot P_{\max} \cdot (1 - FOR_g)] \quad (20)$$

Here, we assume $P_{\max} \cdot (1 - FOR_g)$ is the available capacity of generating unit. A weighting factor is considered in (20) to limit the over-payment by consumer and prevent unacceptable reductions in consumptions as a result of higher prices.

5. CASE STUDY AND DISCUSSIONS

In this section, the capacity expansion problem is analyzed in a two-bus system and investment conditions are discussed in various market structures, including the proposed LCP model. An IEEE 118-bus system is also used to evaluate the effectiveness of proposed approach.

A. Two-bus system

A two-bus system with two existing generators, one candidate generator, and a single load point is considered to illustrate the case. The simplicity and the limited number of elements in the two-bus system, would make it much easier to analyze the effect of market structure on investment decisions, which is the main contribution of this paper. Fig. 4 shows a single diagram of the test system. Generation data are provided in Table 1. The 1900 MW load located in bus 2 will increase at a fixed annual rate of 5%. The transmission constraint is not considered. Investment period is 10 years ($T \in \{1, 2, 3, \dots, 10\}$) and the unit expected lifetime is assumed to be 15 years. Therefore, the maximum planning time would be 25 years. It is assumed that the new installed unit comes to operation at T and the construction time is one year. So the earliest time for a unit to come into service would be one year after the planning period has started, i.e., $T=1$. Table 2 presents the initial generation and the loading condition and price bids. It is assumed that generating units would bid at their marginal price level, which is known.

Figure 4 Single diagram of the 2-bus system

Table 1 GENERATORS DATA

Bus No.	Investment Cost (\$/MW/year)	Capacity (MW)	FOR (%)	Existing (E) or Candidate (C)?
1	-	2000	0.1	E
2	-	2000	0.1	E
2	220,000	2000	0.1	C

Table 2 GENERATORS AND LOAD BIDDING DATA

Unit Name	Bidding Segment No.	MW	Bidding Price (\$/MWh)
G1	1	1000	20
G1	2	600	25
G1	3	400	35
G2	1	1000	38
G2	2	600	40
G2	3	400	45
G3	1	1000	30
G3	2	600	36
G3	3	400	39
Load	1	$L_{peak,t} / 2$	51
Load	2	$L_{peak,t} / 3$	47
Load	3	$L_{peak,t} / 6$	44

A.1. Energy only model

In the energy only model, the market is supposed to provide sufficient incentives to ensure optimal investments in generation expansion. While in theory, an ideal competitive spot market along with ancillary services must identify the key elements necessary for securing the short-term grid operations while maintaining the long-term grid reliability. The power markets in Scandinavia, United Kingdom, Australia, ERCOT and MISO have implemented such models. The latter two markets consider scarcity pricing while developing bilateral forward contracts through energy only markets and legislating proper rules to ensure the active participations of demand side in wholesale markets.

In the energy only model, electricity sales are the only sources of revenue and the capacity scarcity premium is not paid to generation owners. In our study, the market is simulated during the expected lifetime of a new generation. In this market, generators seek to be compensated for high investment costs through price spikes. However, price spikes may not occur often and as expected, which could increase the investor's financial risks. In such cases, generators can benefit from market volatilities which themselves are impediments for investment.

In this case, VOLL is assumed to be 1000 \$/MWh and no price cap is considered. Therefore, the price can jump up to the VOLL in scarcity periods [30]. The profit function, Pr_t , is given in (21). The market objective is to maximize

the social welfare, while in a competitive market a more appropriate objective for individual investors is to maximize the expected profit. However, in a perfect power market, investment decisions based on a centralized social welfare maximization and a decentralized profit maximization would lead to the same results [31].

$$Pr_{gt} = \sum_{t=T}^{T+lf} (LMP_t - OC_{gt}) * P_{gt} \quad (21)$$

Fig. 5 shows that $V^* = \$83.317$ million and $T^* = 4.021$ years. Hence, T is an integer parameter, and a linear approximation is applied to find the optimal investment time. The project NPV becomes positive at 3.421 years. If an investor applies the static NPV assessment, instead of the real options approach, the investment will be possible as soon as the NPV is positive [32]. However, the investment will be more profitable at T^* .

Figure 5 Expected profit with $F(V)$ and $N(V)$ models in energy only market

A.2. Installed capacity model

The application of ICAP in a installed capacity model requires the load serving entities (LSEs) to buy more power than their expected peak capacity in a long-term market, so that they can guarantee a prescribed level of generation capacity. ICAP showed market deficiencies such as providing revenues to the generating units that rarely (or never) were committed. The ICAP model is not affected by the location or time, i.e., late nights and weekends are treated the same as peak hours in hot summers. In essence, there is an incentive for the generation investment in areas with high LMPs. However, ICAP payment can eliminate locational differences in energy prices [33]. This model was adopted in PJM, NY-ISO and NE-ISO before such markets reconsidered the process. Fig. 6 shows the ICAP study results. In this model, LSEs are required to buy 10% more than their expected peak load. The price of ICAP is determined administratively or based on long-term capacity markets. In this case, $V^* = \$111.26$ million and $T^* = 3.267$ while the NPV of project becomes positive at 2.637 years. The dynamic investment assessment [32] would result in postponing the investment decision. However, when the demand is increased in the ICAP model, the system becomes capacity constrained earlier as compared to energy only market and it will be more profitable for generators to make early investments. The project value is increased since there is a revenue source for the installed capacity.

Figure 6 Expected profit with $F(V)$ and $N(V)$ models in ICAP market

A.3. Capacity payment model

Generators in the capacity payment model have an opportunity to earn revenues through regulatory mechanisms as well as energy markets. The additional payment is based on LOLP and VOLL. In this model, there is a regulatory price cap to hedge price spikes, which is significantly smaller than VOLL. Spain, Argentina, Colombia and Chile applied this market model. The main drawback of this model is that generators are inclined to pose artificial outages and exercise market power (e.g., delay the completion of scheduled maintenances or declare artificial outages).

One of the problems with the capacity payment method is that, similar to the ICAP model, the payment is not based on locational attributes. In other words, an increase in LOLP will boost the capacity payment for all generators even those which do not contribute to the system reliability or are located at a distance from capacity-constrained areas. Due to the transmission constraints, remote generating units may not contribute to generation shortages. Therefore, the capacity payment incentive should follow a flexible paradigm (i.e., market-based) rather than providing a uniform revenue for the generating capacity which does not encourage contributions to hedge power shortage. Capacity payment is distributed among generators according to their market contributions. However, at times, a small generation in a strategic location could be more vital than hundreds of megawatt in remote areas. Furthermore, in most cases VOLL is more of an administrative value, which may not show the willingness to pay off the loads and cannot be assumed as a decent signal for the capacity expansion.

Figure 7 Expected profit with $F(V)$ and $N(V)$ models in the CP market

Fig. 7 shows the result for the capacity payment model. The capacity payment is paid here to the available units according to their installed capacity. In this case, $V^* = \$83.985$ millions and $T^* = 4.012$ years while the NPV of project

becomes positive in 3.411 years. Here generators earn extra revenues from the capacity market. However, the market price cap would limit the value of project which is almost the same as that of the energy only market model. Determining the price cap in markets with capacity payment is a challenging task which can limit generator revenues. In an ideal market if the price cap is equal to the average VOLL, an optimal investment along with the acceptable frequency of interruption will occur [34]. However, the average VOLL (e.g. 10,000 \$/MWh) is still significantly higher than the average electricity price (e.g., 50 \$/MWh). Therefore, price caps as high as VOLL may not hedge price spikes. On the other hand, markets with low price caps may not be able to compensate generators, especially peaking units, for their fixed and variable costs.

A.4. Locational capacity price model

In this model, the LCP obtained from (19) is paid to generators as additional revenue. Fig. 8 shows the optimal investment time and value for the LCP approach. Comparing with the first three market models, we learn that the optimal investment occurs earlier, $T^*=4.021$ and $V^*=\$83.317$ million. However, the static NPV rule proposes to invest even earlier at $T=3.421$ year. The interesting result is that, compared to other capacity market mechanisms, the additional revenues in this framework would not obligate the investment to occur prematurely at earlier periods. Another common problem in markets with a capacity mechanism is that, over-investment may occur due to excessive incentive for new expansions. However, the LCP approach does not allow capacity incentives to unnecessarily increase the project value or consumer payments when the system does not require any capacity expansion. In this model, generation units can only get incremental profits by offering additional generation when the system becomes capacity constrained, i.e., LCP is the dual variable of the capacity constraint which is zero when the capacity is still available and the constraint is not binding. For instance, in year 7, the project value increases by about \$100M which means the system is confronting capacity shortages. It is desirable to see the expansion at the right time before scarcity periods; however, when the system security is threatened by generation capacity shortages, LCP increases significantly which raises consumer charges as compared to those in the energy only market. However, in the long-term LCP can ensure the adequacy of capacity which would benefit the system reliability along with consumer satisfactions.

Figure 8 Expected profit with $F(V)$ and $N(V)$ models in the LCP market

In all the case studies, the discount rate $\rho = 0.1$. A sensitivity analysis is performed to show the correlation between

the results (i.e., optimal investment time and value) and discount rates. As Table 3 shows that the investment time is delayed and the value of project is decreased by increasing the discount rate.

Table 3 SENSITIVITY ANALYSIS ON DISCOUNT RATE

Discount rate (ρ)	0.01	0.05	0.10	0.15	0.20	0.25
T^* (Year)	2.78	3.30	4.02	4.72	5.35	5.87
V^* (\$)	2.79E+08	1.62E+08	8.33E+07	4.29E+07	2.23E+07	1.17E+07

A.4.1. Multi-level load bidding

In this model, multi-level load bidding is considered. In Fig. 9 each load (or group of loads) submits a set of bids to the market according to its preferred demand level. The capacity index is introduced as a deduction margin below the peak demand for serving load. For instance, a 100 MW load with a capacity index of 0.1 is presented as 90 MW. This addresses the problem of demand overpayments in real markets when there is a limited number of cheap units or generation capacity in general. Here, the overpayment refers to a case when a load would bid a certain MW value; however, when the market is cleared, the load is partially supplied at a high rate. A multi-level load bid allows loads to pay lower rates if they are partially supplied. In Fig. 9, solid line represents the load's first priority to be served fully (Alternative 1), dashed line shows the load tendency to stay in the market at 90 percent of its initial schedule (Alternative 2), and gray color line shows the load to be served at 80 percent (Alternative 3).

Figure 9 Multi-level load bidding

This forms an MIP problem in which the loads have i bidding segments and each segment has j alternatives that at most, one of these alternatives can be served in full or zero quantity.

$$L_{ijt} = \sum_l \sum_i \sum_j U_{lijt} * Load_{lijt} \quad (22)$$

$$\sum_j U_{lijt} \leq 1 \quad \forall i = 1, 2, \dots, NS_{lt} \quad , \quad \forall j = 1, 2, \dots, NA_{lit} \quad (23)$$

Fig. 10 shows the market simulation results when the loads bid more than a single price at each segment. Here the optimal investment time and project value are the same as Case A.4. However, as shown in Fig. 10, when the system is on the verge of becoming capacity-constrained, the project value would change dramatically as the demand would provide more information on its tendency to be shed or not, i.e. different level of price bids to minimize the load loss. As shown in Figs. 8 and 10, the trend in the project value would be different when we use the LCP rather than the

other three approaches (Figs. 5-7). The major distinction in the LCP model is that the slope changes (increases) significantly, closer to the end of planning period, i.e. scarcity periods. This makes sense, because generators are getting paid by LCP only if they reach their capacity limits. Since, the demand increases during the planning period, the chance of that new generator works at full capacity in ending years will be higher, and the value of the project is larger accordingly.

Figure 10 Expected profit with $F(V)$ and $N(V)$ models in the LCP market with multi-level load bidding

B. IEEE 118- Bus System

A modified IEEE 118 bus system is used to study the proposed LCP approach. The system has 54 units, 186 branches, nine tap-changing transformers, and 91 demand sides. The peak load is 3,733 MW. The test data for the 118-bus system are given in motor.ece.iit.edu/data/SCUC_118test.xls. Fig. 11 shows the LMP results using the optimal power flow (DC-OPF). Here, bus 56 shows the highest LMP where there is an incentive to install new generating units [35]. Therefore, we select bus 56 as a first candidate site for generation expansion. However, to investigate the effectiveness of LCP, we select buses 95 and 83 that represent an average and the lowest LMPs, respectively. Furthermore, buses 59 and 89 are considered as they have the largest installed load (277 MW) and transmission capacity accessibility (2600 MW), respectively. Similar to the study in section IV.A, we simulate market operations for the expected life of the new generation and investigate the optimal timing and value for the expansion project. The new unit has the capacity of 200 MW and an operating marginal cost of 12.64 \$/MWh. The load growth rate is assumed to be one percent over the lifetime of the project and the investment cost is the same as that in section IV.A.

Table 4 shows the results for installing the new unit in different sites using the LCP and the energy only market models. The investment here occurs in the earliest time and with the highest value of return. The investment in year zero means that there is no reason to delay the expansion as soon as other constraints such as land acquisitions and project permits are met. As expected, it is not profitable to add any generation capacity in bus 83 with the lowest LMP. Bus 59 is a suitable candidate especially in transmission-constrained systems as it shows two positive factors including a high LMP and a large demand quantity. It is also profitable to choose bus 95 using the LCP approach. However, in all cases, the generation expansion would occur in earlier years if the locational capacity mechanism is considered in the market structure. Furthermore, investments would have a true market-based signal to find the best location for their expansion projects.

Figure 11 Bus LMPs in the IEEE 118-bus

Table 4: OPTIMAL INVESTMENT TIME AND VALUE

Bus No.	LMP (\$/MWh)	LCP Model			Energy Only Model		
		Optimal Investment Time (year)		Optimal Project Value (M\$)	Optimal Investment Time (year)		Optimal Project Value (M\$)
		F(V)	N(V)		F(V)	N(V)	
56	13.33	0	0	208.504	5.03	4.49	0.938
59	12.96	0	0	207.69	5.04	4.50	0.936
83	9.92	NI*	NI	(3.084)	NI	NI	(3.084)
89	11.63	NI	NI	(3.084)	NI	NI	(3.084)
95	12.64	6.98	6.48	0.639	NI	NI	(3.029)

* No investment

6. CONCLUSIONS

It was shown that with low VOLL values, the energy only market model might not guarantee the capacity adequacy in power systems. Therefore, it is essential to have a capacity mechanism to ensure that there will be enough capacity available to prevent the scarcity as the system load grows. Capacity payment and installed capacity models have shown planning deficiencies because they do not include locational and temporal variables. Furthermore, the aforementioned capacity mechanisms may incur burdensome and excessive payments at demand side. The proposed LCP model provides an efficient solution for a market-based capacity mechanism while would not increase load payments if the new expansion has occurred at the right time, i.e. before scarcity period. LCP brings about the following benefits:

- Allows cost effective investments at earlier years before capacity shortages occur.
- Enables the creation of true capacity markets as it follows market trends and provides market-based investment signals.
- Provides generation companies with additional revenues to hedge investment risks.
- Encourages generation units to declare the available capacity in the market rather than exercising any market power.
- Is easily adapted to various market structures.
- Would not increase load payments in normal operation conditions.

Furthermore, the value of project provides investment signals when the system is on the verge of facing capacity

shortages while risks are borne by investors rather than consumers. The installed capacity model would lead to additional capacity investments while transferring considerable revenues, as capacity incentive payments, from consumers to suppliers. However, the LCP, along with multi-level load bidding would result in efficient capacity investments as well as a higher social welfare since it highlights consumer preferences for an uninterrupted supply. In the long-term, the proposed model will contribute to healthier electricity market designs and fewer administrative regulations in favor of robust capacity adequacy options.

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8. BIOGRAPHIES

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Security-Constrained Unit Commitment with AC/DC Transmission Systems

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Abstract—This paper presents the solution to the security-constraint unit commitment (SCUC) problem with a detailed representation of high voltage direct current (DC) transmission system with current source converters (CSCs). The SCUC problem is decomposed into a master problem for solving unit commitment (UC) problem and hourly transmission security check subproblems that evaluate branch flows and bus voltages of integrated AC/DC transmission systems. The solution of the transmission security check subproblem is based on a linear programming (LP) formulation that minimizes AC bus mismatches subject to AC/DC transmission constraints. The final SCUC solution prescribes an economic and secure operation and control strategy for AC/DC transmission systems and coordinates DC power transfers for enhancing the economics and the security of AC transmission systems. Numerical tests illustrate the efficiency of the proposed AC/DC transmission model.

Index Terms—AC/DC transmission systems, current source converters, security-constrained unit commitment, Benders decomposition.

NOMENCLATURE

b Index for AC buses
 c Index for contingencies
 h Index for DC converters
 i Index for generating units
 l Index for transmission lines
 m Index for AC bus terminals connected to converters
 $I_{dc,h}$ DC current of converter h
 $MP_{b,1}, MP_{b,2}$ Slack variables for the real power mismatch at bus b (≥ 0)
 $MQ_{b,1}, MQ_{b,2}$ Slack variables for the reactive power mismatch at bus b (≥ 0)
 NB Number of ac buses
 P_m, Q_m Real and reactive power withdrawals at bus m
 P_m^{inj}, Q_m^{inj} Real and reactive power injections at bus m
 $P_{term,h}, Q_{term,h}$ Real and reactive power of converter h
 R_{dc} Resistance of DC line
 T_h Off-nominal tap ratio of the transformer connected to converter h
 $V_{dc,h}$ DC voltage of converter h
 V_m AC bus voltage at bus m
 w Objective value of SCUC subproblem
 $X_{c,h}$ Commutation reactance of converter h
 α_h Firing/extinction angle of converter h

ϕ_h Power factor angle of converter h ($0 \leq \phi_h \leq \frac{\pi}{2}$ for rectifier, $-\frac{\pi}{2} \leq \phi_h \leq 0$ for inverter)
 ΔP_m Real power mismatch at bus m
 ΔQ_m Reactive power mismatch at bus m
 $\Delta R1_h, \Delta R2_h, \Delta R3_h$ DC mismatches of converter h
 Δ_i Permissible real power adjustment for unit i
 A Bus-unit incidence matrix
 G_h Admittance matrix of DC transmission system for converters h
 I Unit state vector
 $I_{dc}, \Delta I_{dc}$ DC current vector and its incremental vector
 $J1, J2, J3, J4$ Jacobian matrices
 $MP1, MP2$ Mismatch vector for real power slack variables
 $MQ1, MQ2$ Mismatch vector for reactive power slack variables
 $P, \Delta P$ Real power generation vector and its increment
 Q_{max}, Q_{min} Upper and lower limit vectors for reactive power generation
 V, V_{dc} AC and DC bus voltage vectors
 x Vector of SCUC variables
 $\phi, \Delta\phi$ Power factor angle vector and its increment
 $\alpha, \Delta\alpha$ Firing/extinction angle vector and its increment
 $\delta, \Delta\delta$ Bus phase angle vector and its increment
 $\pi, \psi, \bar{\psi}$ Simplex multiplier vectors
 dP_0 Initial AC bus real power mismatch vector
 dQ_0 Initial AC bus reactive power mismatch vector
 $dR1_0, dR2_0, dR3_0$ Initial mismatch vectors for DC equations
 $\Delta I_{dc,max}, \Delta I_{dc,min}$ Upper and lower limit vectors for incremental converter currents
 $\Delta PL_{ac}, \Delta PL_{dc}$ Increment vectors for AC and DC line flows
 $\Delta PL_{ac,max}, \Delta PL_{ac,min}$ Upper and lower limit vectors for incremental AC line flows
 $\Delta PL_{dc,max}, \Delta PL_{dc,min}$ Upper and lower limit vectors for incremental DC line flows
 ΔQ Incremental vector of reactive power generation
 $\Delta Q_{max}, \Delta Q_{min}$ Upper and lower limit vectors for incremental unit reactive power
 ΔT Increment vector for transformer taps
 $\Delta T_{max}, \Delta T_{min}$ Upper and lower limit vectors for incremental transformer taps
 $\Delta V, \Delta V_{dc}$ Increment vectors for AC and DC bus voltages

$\Delta V_{\max}, \Delta V_{\min}$ Upper and lower limit vectors for incremental AC voltages
 $\Delta \gamma$ Increment vector for phase-shifter angles
 $\Delta \gamma_{\max}, \Delta \gamma_{\min}$ Upper and lower limit vectors for incremental phase shifter angles
 $\Delta \alpha_{\max}, \Delta \alpha_{\min}$ Upper and lower limit vectors for incremental firing/extinction angles
 $\Delta \phi_{\max}, \Delta \phi_{\min}$ Upper and lower limit vectors for incremental power factor angles

I. INTRODUCTION

DC transmission systems are often considered for delivering bulk power via long distances. The attributes of DC transmission systems include low capacitance, low average transmission cost in long distances, ability to prevent cascaded outages in AC transmission systems, rapid adjustments for direct power flow controls, ability to improve the stability of AC transmission systems, mitigation of transmission congestion, enhancement of transmission capacity, rapid frequency control following a loss of generation, ability to damp out regional power oscillations following major contingencies, and offering major economic incentives for supplying loads [1-4]. Flexible and fast DC controls provide efficient and desirable performance for a wide range of AC transmission systems [5].

Proper control modes applied to rectifiers (source) and inverters (sink) could maintain DC voltages near rated values and set power factors as high as possible. DC transmission system would require two control modes out of five for source and sink operations. The control modes include fixed firing/extinction advance angles, tap setting of converter transformers, DC currents, DC voltages, and DC power [6,7]. The selection of DC control modes depends on the nature of specific applications for enhancing the economic and security.

DC transmission system configurations include monopolar, bipolar, tripolar, and multi-terminal which are used in diverse applications including the reinforcement of AC transmission flows and the interconnection of several AC transmission systems with different operating frequencies [8].

In the past, DC transmission systems were modeled in the optimal power flow (OPF) problem to analyze the impact of DC transmission systems on the operation of AC transmission systems [9,10]. Several numerical techniques such as unified and sequential methods were considered for solving integrated AC/DC transmission flow equations [11-13]. The unified method solves AC and DC power flow equations simultaneously. The sequential method applies an iterative procedure between AC and DC transmission systems.

With the advent of electricity restructuring, DC transmission systems were utilized to maintain the system security and decrease social costs. The simplest approach to consider DC transmission systems in SCUC was to regard DC terminals as constant power injections or withdrawals in AC transmission systems [14-16]. However, such simplified models in SCUC may ignore the dependency of AC power flows to DC transmission variables.

Fig. 1 depicts the market clearing process for AC/DC transmission systems. The AC system includes AC generators, loads, and transmission lines. The DC transmission system is composed of converter terminals and DC transmission lines. At first, the independent system operator (ISO) receives supply/demand bids and collects AC/DC transmission data provided by transmission companies (TRANSCOs). Once the market is cleared, the ISO will send hourly schedules (unit commitment, generation dispatch, and load schedules) to the AC system and optimal control strategies to the TRANSCOs which will activate control signals (tap-changing and phase-shifting transformers, adjustable shunt capacitors, firing angles of thyristors, and taps of converter transformers) to operate AC/DC transmission systems.

Fig. 1. Market clearing process with AC/DC transmission

Since most DC transmission installations in the world use a line-commutation based current source converter (CSC) [17], we study in this paper the application of CSC-DC transmission system. The other option for the modeling of DC transmission system is based on the voltage source converter (VSC-DC) [18-20]. The application of VSC-DC to SCUC is under investigation and will appear in our subsequent publications. The proposed SCUC model would secure the power flow solution and optimize the hourly UC by a set of proper control strategies of AC/DC transmission systems. The SCUC solution for handling AC/DC transmission constraints applies Benders decomposition for mitigating transmission congestion and improving power system economics while satisfying system security constraints including transmission flow and bus voltage limits. Once a credible contingency occurs on AC/DC transmission lines or generating units, contingency subproblems will minimize transmission violations. In such cases, preventive actions will accommodate uncontrollable contingencies by transferring the base case operating point to a secure state. A corrective action will otherwise be considered for accommodating controllable contingencies [21].

The rest of the paper is organized as follows. Section II models the CSC (DC terminal) and power flow equations for the DC transmission system. The SCUC formulation with AC/DC transmission constraints and Benders decomposition based solution are presented in Section III. The proposed algorithm is tested with the IEEE 14-bus and IEEE 118-bus systems in Section IV. We summarize the conclusion in Section V.

II. DC TRANSMISSION SYSTEM MODEL

DC transmission systems consist of at least two converters (i.e., rectifiers and inverters) and overhead lines that link converters. In order to eliminate harmonics generated by AC/DC systems, AC filters are installed on the AC side of DC terminals. In this section, we review DC transmission systems and corresponding DC power flow equations for our SCUC formulation.

A. CSC Model

Fig. 2 presents a typical CSC system which is connected to AC bus m through a coupling transformer. In order to model the CSC h which is linked to the AC bus m , five converter variables, i.e., $V_{dc,h}$, $I_{dc,h}$, T_h , α_h , and ϕ_h are considered in Fig. 2. These variables determine the DC line operating state.

Fig. 2. Schematic Diagram of a CSC-DC system

A converter, either a rectifier or an inverter, is modeled by (1)-(3). The converter equations (1) and (2) express $V_{dc,h}$ in terms of V_m and other converter variables while the coupling transformer is assumed to be lossless. The converter equation (3), which can be expressed using a nodal-mesh procedure, represents the DC voltage-current relationship which depends on the DC transmission system configuration (i.e., monopole, bipole, tri-pole, or a multi-terminal link).

$$V_{dc,h} = \frac{3\sqrt{2}}{\pi} T_h V_m \cos \alpha_h - \frac{3}{\pi} X_{c,h} I_{dc,h} \quad \text{rectifier} \quad (1)$$

$$V_{dc,h} = -\frac{3\sqrt{2}}{\pi} T_h V_m \cos \alpha_h + \frac{3}{\pi} X_{c,h} I_{dc,h} \quad \text{inverter}$$

$$V_{dc,h} = 0.995 \frac{3\sqrt{2}}{\pi} T_h V_m \cos \phi_h \quad \text{rectifier} \quad (2)$$

$$V_{dc,h} = -0.995 \frac{3\sqrt{2}}{\pi} T_h V_m \cos \phi_h \quad \text{inverter} \quad (3)$$

$$f(\mathbf{V}_{dc}, I_{dc,h}) = 0$$

Here, (3) for converter h is rewritten as (4) in a matrix form,

$$I_{dc,h} - \mathbf{G}_h \cdot \mathbf{V}_{dc} = 0 \quad (4)$$

where, $\mathbf{G}_h$ is the admittance matrix of DC transmission system for converter h . A DC terminal is selected as slack bus in each DC transmission system. Similar to that in an AC transmission system, the slack bus balances the real power among DC terminals in the DC transmission system [22].

B. Control Modes of DC Transmission Systems

Each CSC (rectifier or inverter) is regulated by two out of

five control modes. The modes are.

1) Constant current (CC)

$$I_{dc,h} = \text{const}$$

2) Constant voltage (CV)

$$V_{dc,h} = \text{const}$$

3) Constant power (CP)

$$P_{term,h} = V_{dc,h} I_{dc,h} = \text{const}$$

4) Constant firing/extinction angle (CFA/CEA)

$$\alpha_h = \text{const}$$

5) Constant transformer tap ratio (CTR)

$$T_h = \text{const}$$

The selection of two control modes would maximize the economic benefits of DC transmission systems while keeping all variables within their limits. The rules for selecting effective CSC control modes are given below [1-3],

Rule 1: At least one converter in each DC transmission system would select CV as the first control mode; other converters would maintain CC as the first control mode. If converters are not operating at their minimum firing/extinction angles, CP may be applied as the second control mode.

Rule 2: If a rectifier is not operating at its minimum firing angle, the rectifier would be operated as (CC/CP plus CV). For an inverter which is not operating at its minimum extinction angle, (CC/CP/CV plus CEA) is selected.

Rule 3: Once the minimum firing angle of rectifier is reached, the rectifier would switch from (CC plus CV) to (CFA plus CTR). In this case, the inverter would maintain CC plus CEA.

Rule 4: If an inverter is operating at its minimum extinction advance angle, it would switch to (CC/CP/CV plus CTR).

C. Power Flow Equations of DC Transmission Systems

Using the per-unit system given in Appendix A, nodal power balance equations at the AC bus m that is linked to converter h are listed as

$$\Delta P_m = P_m^{inj} - P_m - P_{term,h} = 0 \quad (5)$$

$$\Delta Q_m = Q_m^{inj} - Q_m - Q_{term,h} = 0 \quad (6)$$

where,

$$P_{term,h} = V_{dc,h} I_{dc,h} \quad (7)$$

$$Q_{term,h} = V_{dc,h} I_{dc,h} \tan \phi_h \quad (8)$$

CSC always consumes reactive power and $Q_{term,h}$ is non-negative. Similarly, (1), (2) and (4) are replaced in pu as

$$\begin{cases} \Delta R1_h = V_{dc,h} - T_h V_m \cos \alpha_h + X_{c,h} I_{dc,h} = 0 & \text{rectifier} \\ \Delta R1_h = V_{dc,h} + T_h V_m \cos \alpha_h - X_{c,h} I_{dc,h} = 0 & \text{inverter} \end{cases} \quad (9)$$

$$\begin{cases} \Delta R2_h = V_{dc,h} - 0.995 T_h V_m \cos \phi_h = 0 & \text{rectifier} \\ \Delta R2_h = V_{dc,h} + 0.995 T_h V_m \cos \phi_h = 0 & \text{inverter} \end{cases} \quad (10)$$

$$\Delta R3_h = I_{dc,h} - \mathbf{G}_h \mathbf{V}_{dc} = 0 \quad (11)$$

In the next section, we will apply the Newton-Raphson method that utilizes the linearized version of (5)-(11) for the network

security violation checking in base case and contingency conditions.

III. SCUC WITH DC CONSTRAINTS

A. Formulation of SCUC with AC/DC Constraints

SCUC is generalized in (12) where $f(\mathbf{x})$ is composed of production cost, and start up and shut down costs of individual units for the study horizon [21, 23-25].

$$\begin{aligned} \text{Min } & f(\mathbf{x}) \\ \text{s.t. } & \\ & \mathbf{g1}(\mathbf{x}) \leq \mathbf{b1} \\ & \mathbf{ge1}(\mathbf{x}) = \mathbf{be1} \\ & \mathbf{g2}(\mathbf{x}) \leq \mathbf{b2} \\ & \mathbf{ge2}(\mathbf{x}) = \mathbf{be2} \end{aligned} \quad (12)$$

where $\mathbf{x}$ is composed of on/off status and generation of generating units, startup and shutdown indicators, and AC/DC transmission system variables. The first set of inequality constraints $\mathbf{g1}(\mathbf{x}) \leq \mathbf{b1}$ and equality constraints $\mathbf{ge1}(\mathbf{x}) = \mathbf{be1}$ represents UC constraints such as,

1. Power balance
2. Generating unit capacity
3. System spinning and operating reserve requirements
4. Ramping up/down limits
5. Minimum up/down time limits
6. Maximum number of simultaneous on/off's in a plant
7. Maximum number of on/off's of a unit in a given period
8. Fuel and multiple emission limits

The second set of inequality constraints $\mathbf{g2}(\mathbf{x}) \leq \mathbf{b2}$ and equality constraints $\mathbf{ge2}(\mathbf{x}) = \mathbf{be2}$ includes

9. AC/DC power flow equations
10. Limits on AC/DC control variables including real and reactive power generations, controlled shunt capacitors, tap-changing and phase-shifting transformers, firing/extinction angles and coupling transformer tap ratios of converters
11. AC/DC network security constraints including AC/DC transmission flow and bus voltage limits, and limits to DC currents, voltages and power of converters
12. Time limited corrective controls, such as permissible real power adjustments, for handling contingencies

B. Solution of SCUC with AC/DC Constraints

We apply the Benders decomposition to solve the SCUC with AC/DC transmission systems as depicted in Fig. 3. The master problem applies MIP for solving the UC problem. The Newton-Raphson based subproblem is utilized to check transmission flows and bus voltages in base case and contingency conditions. The SCUC subproblem considers both real and reactive power mismatches at AC buses which are minimized based on optimal adjustments of scheduled power generation, tap-changing transformers, and phase shifters in the AC system, and by adjusting DC transmission controls (e.g. converter firing/extinction advance angles and transformer tap settings). The subproblem generates Benders cuts for the next UC iteration once the mismatch exists in either base case or

contingencies. This iterative procedure will continue until all mismatches are removed.

Fig. 3 SCUC with AC/DC transmission systems

C. SCUC Subproblem for Base Case

The subproblem for base case is formulated as (13)-(26). (14)-(26) represents AC/DC power flow equations, limits on real and reactive power generations, AC and DC line flows, real power withdrawals at AC converter buses, AC bus voltages magnitudes, transformer tap settings, phase shifter angles, DC bus voltages, DC voltages and currents of converters, converter firing/extinction advance angles, and converter power factor (lagging/leading) angles, respectively. Note that (15) is for all generating units except the ones at the slack bus. Appendix B lists the elements of Jacobian matrices $\mathbf{J1}$, $\mathbf{J2}$, $\mathbf{J3}$, and $\mathbf{J4}$ for DC transmission systems.

$$\text{Min } w = \sum_{b=1}^{NB} (MP_1 p_b + MP_2 p_b + MQ_1 p_b + MQ_2 p_b) \quad (13)$$

$$\begin{bmatrix} \mathbf{A} \cdot \Delta \mathbf{P} \\ \mathbf{A} \cdot \Delta \mathbf{Q} \\ \mathbf{0} \\ \mathbf{0} \\ \mathbf{0} \end{bmatrix} - [\mathbf{J1}] \begin{bmatrix} \Delta \delta \\ \Delta \mathbf{V} \\ \Delta \mathbf{T} \\ \Delta \gamma \\ \Delta \mathbf{V}_{dc} \\ \Delta \mathbf{I}_{dc} \\ \Delta \alpha \\ \Delta \phi \end{bmatrix} + \begin{bmatrix} \mathbf{MP1} \\ \mathbf{MQ1} \\ \mathbf{0} \\ \mathbf{0} \\ \mathbf{0} \end{bmatrix} - \begin{bmatrix} \mathbf{MP2} \\ \mathbf{MQ2} \\ \mathbf{0} \\ \mathbf{0} \\ \mathbf{0} \end{bmatrix} = \begin{bmatrix} \mathbf{dP}_0 \\ \mathbf{dQ}_0 \\ \mathbf{dR1}_0 \\ \mathbf{dR2}_0 \\ \mathbf{dR3}_0 \end{bmatrix} \quad (14)$$

$$\Delta \mathbf{P} = \mathbf{0} \quad \pi \quad (15)$$

$$\Delta \mathbf{Q}_{\min} \leq \Delta \mathbf{Q} \leq \Delta \mathbf{Q}_{\max} \quad \underline{\psi}, \overline{\psi} \quad (16)$$

$$\Delta \mathbf{P}_{ac, \min} \leq \Delta \mathbf{P}_{ac} = [\mathbf{J2}] \begin{bmatrix} \Delta \delta \\ \Delta \mathbf{V} \\ \Delta \mathbf{T} \\ \Delta \gamma \end{bmatrix} \leq \Delta \mathbf{P}_{ac, \max} \quad (17)$$

$$\Delta \mathbf{P}_{dc, \min} \leq \Delta \mathbf{P}_{dc} = [\mathbf{J3}] \begin{bmatrix} \Delta \mathbf{V}_{dc} \\ \Delta \mathbf{I}_{dc} \end{bmatrix} \leq \Delta \mathbf{P}_{dc, \max} \quad (18)$$

$$\Delta \mathbf{P}_{term, \min} \leq \Delta \mathbf{P}_{term} = [\mathbf{J4}] \begin{bmatrix} \Delta \mathbf{V}_{dc} \\ \Delta \mathbf{I}_{dc} \end{bmatrix} \leq \Delta \mathbf{P}_{term, \max} \quad (19)$$

$$\Delta V_{\min} \leq \Delta V \leq \Delta V_{\max} \quad (20)$$

$$\Delta T_{\min} \leq \Delta T \leq \Delta T_{\max} \quad (21)$$

$$\Delta \gamma_{\min} \leq \Delta \gamma \leq \Delta \gamma_{\max} \quad (22)$$

$$\Delta V_{dc,\min} \leq \Delta V_{dc} \leq \Delta V_{dc,\max} \quad (23)$$

$$\Delta I_{dc,\min} \leq \Delta I_{dc} \leq \Delta I_{dc,\max} \quad (24)$$

$$\Delta \alpha_{\min} \leq \Delta \alpha \leq \Delta \alpha_{\max} \quad (25)$$

$$\Delta \phi_{\min} \leq \Delta \phi \leq \Delta \phi_{\max} \quad (26)$$

The steps for solving the SCUC subproblem include,

Step 1: Calculate elements of corresponding Jacobian matrices J_1 , J_2 , J_3 , and J_4 , initial AC bus mismatch vectors dP_0 and dQ_0 , and initial DC power mismatch $dR1_0$, $dR2_0$ and $dR3_0$. The calculation is based on the initial UC solution and the given AC/DC transmission system state.

Step 2: Use LP to minimize (13) and calculate changes in the AC/DC transmission state and control variables.

Step 3: Update state and control variables. Recalculate elements of Jacobian matrices and mismatch vectors.

Step 4: Minimize (13) and calculate changes in AC/DC transmission system state and control variables. If the difference between the last two iterative changes is less than a specified tolerance, stop the process. Otherwise, go back to Step 3.

If w is larger than zero, a mismatch Benders cut (27) will be formed and added to the UC problem for calculating the next iterative solution of master problem.

$$w + \pi(P - \hat{P}) + \bar{\psi}Q_{\max}(\mathbf{I} - \hat{\mathbf{I}}) - \underline{\psi}Q_{\min}(\mathbf{I} - \hat{\mathbf{I}}) \leq 0 \quad (27)$$

where $\hat{\mathbf{I}}$ and $\hat{P}$ are the UC and generation dispatch results in the current iteration, respectively.

D. SCUC Subproblem for Contingencies

The subproblem for a contingency c is formulated in (28)-(41). The objective function (28) is introduced according to the Newton-Raphson method for minimizing real and reactive bus power mismatches and calculating a converged AC power flow solution subject to transmission flow and bus voltage limits.

In each contingency case, corrective and preventive actions are considered for managing AC/DC violations. Corrective actions refer to the redispatch of generating units and adjustments of transmission flow controls for mitigating transmission flow violations in real time. Preventive actions refer to day-ahead adjustments of transmission flows by applying transformer controls, as well as UC and economic dispatch (ED) of generating units. Preventive actions will be applied if corrective actions are not feasible in real time. (30) represents the physically acceptable corrective action for generating units [25].

$$\min w^c = \sum_{b=1}^{NB} (MP1_b^c + MP2_b^c + MQ1_b^c + MQ2_b^c) \quad (28)$$

$$\begin{bmatrix} \mathbf{A} \cdot \Delta \mathbf{P}^c \\ \mathbf{A} \cdot \Delta \mathbf{Q}^c \\ \mathbf{0} \\ \mathbf{0} \\ \mathbf{0} \end{bmatrix} - [\mathbf{J}_1] \begin{bmatrix} \Delta \delta^c \\ \Delta V^c \\ \Delta T^c \\ \Delta \gamma^c \\ \Delta V_{dc}^c \\ \Delta I_{dc}^c \\ \Delta \alpha^c \\ \Delta \phi^c \end{bmatrix} + \begin{bmatrix} \mathbf{MP1}^c \\ \mathbf{MQ1}^c \\ \mathbf{0} \\ \mathbf{0} \\ \mathbf{0} \end{bmatrix} - \begin{bmatrix} \mathbf{MP2}^c \\ \mathbf{MQ2}^c \\ \mathbf{0} \\ \mathbf{0} \\ \mathbf{0} \end{bmatrix} = \begin{bmatrix} dP_0^c \\ dQ_0^c \\ dR1_0^c \\ dR2_0^c \\ dR3_0^c \end{bmatrix} \quad (29)$$

$$|P^c - \hat{P}^0| \leq \Delta \pi^c, \underline{\pi}^c \quad (30)$$

$$\Delta Q_{\min}^c \leq \Delta Q^c \leq \Delta Q_{\max}^c \quad \underline{\psi}^c, \bar{\psi}^c \quad (31)$$

$$\Delta PL_{ac,\min}^c \leq \Delta PL_{ac}^c \leq \Delta PL_{ac,\max}^c \quad (32)$$

$$\Delta PL_{dc,\min}^c \leq \Delta PL_{dc}^c \leq \Delta PL_{dc,\max}^c \quad (33)$$

$$\Delta P_{term,\min}^c \leq \Delta P_{term}^c \leq \Delta P_{term,\max}^c \quad (34)$$

$$\Delta V_{\min}^c \leq \Delta V^c \leq \Delta V_{\max}^c \quad (35)$$

$$\Delta T_{\min}^c \leq \Delta T^c \leq \Delta T_{\max}^c \quad (36)$$

$$\Delta \gamma_{\min}^c \leq \Delta \gamma^c \leq \Delta \gamma_{\max}^c \quad (37)$$

$$\Delta V_{dc,\min}^c \leq \Delta V_{dc}^c \leq \Delta V_{dc,\max}^c \quad (38)$$

$$\Delta I_{dc,\min}^c \leq \Delta I_{dc}^c \leq \Delta I_{dc,\max}^c \quad (39)$$

$$\Delta \alpha_{\min}^c \leq \Delta \alpha^c \leq \Delta \alpha_{\max}^c \quad (40)$$

$$\Delta \phi_{\min}^c \leq \Delta \phi^c \leq \Delta \phi_{\max}^c \quad (41)$$

If w_c is larger than zero, a mismatch Benders cut (42) for contingency c will be formed and added to the master UC problem for calculating the next iterative solution.

$$w^c + \pi^c(P - \hat{P}^0) + \bar{\psi}^c Q_{\max}(\mathbf{I} - \hat{\mathbf{I}}^0) - \underline{\psi}^c Q_{\min}(\mathbf{I} - \hat{\mathbf{I}}^0) \leq 0 \quad (42)$$

IV. NUMERICAL EXAMPLES

The modified IEEE 14-bus system and the IEEE 118-bus system are studied. Optimal control strategies for DC transmission systems are determined based on SCUC results. We set the mismatch tolerance at 0.001 pu (or 0.1 MVA). Numerical examples presented in this section are mainly to show the economic benefits of DC system while maintaining the system security in base case and contingency conditions.

A. IEEE-14 Bus System

The IEEE-14 bus system depicted in Fig. 4 is considered with pertinent data listed in Appendix C. This system has 5 generating units, 20 branches, 11 loads and 3 transformers. Bus 1 is selected as slack bus. The following cases are considered to examine the efficiency of the proposed model.

Case 0: UC solution without transmission constraints

Case 1: SCUC solution with AC transmission constraints

Case 2: ED solution when line 1-5 is replaced with a two-terminal DC line

Case 3: SCUC solution for Case 2

Case 4: SCUC for Case 1 considering the outage of line 2-3

Case 5: SCUC for Case 3 considering the outage of line 2-3

Fig. 5. Two-terminal DC transmission line

Case 3: A new SCUC is calculated to examine the impact of the DC line flows. Tables V and VI show the UC and ED results. The bold numbers show the difference between Cases 3 and 1. Compared with Case 1, the more expensive unit 3 is off at hours 3 and 6 to reduce the operating cost since the DC transmission system allows the cheapest unit 1 to increase its generation. In fact, the DC line can transfer additional power (compared to the AC line 1-5 flow in Case 1) from bus 1 to bus 5 which results in the mitigation of congestion on line 1-2 and the additional dispatch of cheapest unit 1. Consequently, it is not necessary to turn on the more expensive unit 3 for supplying the load at hour 3. In addition, the expensive units 4 & 5 are committed to maintain bus voltages within their limits. In this case, the system operating cost drops to \$61,212.71 which is reduced by \$64,086.07 - \$61,212.71 = \$2,873.36 as compared with Case 1.

TABLE V
UC IN CASE 3

Unit	Hours (1-24)
1	1111111111111111111111111111
2	1111111111111111111111111111
3	1100101111111111111111111111
4	1110011111111111111111111111
5	0000000111111101111111111111

TABLE VI
GENERATION DISPATCH IN CASE 3

Hour	Unit 1	Unit 2	Unit 3	Unit 4	Unit 5
1	94.69	50.00	17.56	22.43	0.00
2	100.20	50.00	14.18	10.00	0.00
3	90.35	50.00	0.00	13.09	0.00
4	85.62	20.00	0.00	0.00	0.00
5	93.61	26.32	12.00	0.00	0.00
6	96.67	50.00	0.00	12.32	0.00
7	94.69	50.00	17.56	22.43	0.00
8	104.99	50.00	30.45	10.00	10.00
9	106.28	50.00	39.61	10.00	10.00
10	108.22	50.00	53.28	10.00	10.00
11	108.49	50.00	55.63	10.00	10.00
12	106.93	50.00	44.16	10.00	10.00
13	105.64	50.00	35.04	10.00	10.00
14	96.07	50.00	43.98	10.00	0.00
15	108.22	50.00	53.28	10.00	10.00
16	108.86	50.00	57.86	10.00	10.00
17	107.20	50.00	46.50	10.00	10.00
18	108.49	50.00	55.63	10.00	10.00
19	110.09	50.00	67.08	10.00	10.00
20	109.34	50.00	75.06	13.19	10.00
21	106.80	50.00	77.72	18.20	10.00
22	108.86	50.00	57.86	10.00	10.00
23	107.85	50.00	51.06	10.00	10.00
24	106.28	50.00	39.61	10.00	10.00

Table VII shows the hourly bus power mismatch per iteration. Bus power mismatches have decreased significantly at the second SCUC iteration in comparison with those at the first iteration. At the third SCUC iteration, the bus power

mismatch at certain hours is smaller than the tolerance of 0.1 MVA. Consequently, no Benders cut are generated at those hours and the number of cuts have decreased from 24 at iteration 1 to 7 at iteration 5. There are no mismatches after 7 iterations. The economic control strategy of DC transmission system is devised based on the optimal operation of converters shown in Tables VIII and IX. This control scheme would be specified for each rectifier/inverter terminal in order to maintain two out of five control modes. Table X shows a set of 24-hour control strategies for the DC transmission system. At hour 1, the rectifier is operating at its minimum firing angle of $\alpha_r = 5$ Deg (in Table VIII) and, according to Rules 1 and 3, the first control mode is CFA=5 Deg and the rectifier maintains CTR=1.09 pu. At this hour, the inverter maintains CC=129 A and CV=-1.10 pu.

TABLE VII

HOURLY NODAL MISMATCH PER ITERATION OF SCUC (MVA) IN CASE 3							
Hour	Iter1	Iter2	Iter3	Iter4	Iter5	Iter6	Iter7
1	106.00	28.34	13.24	3.09	0.28	<0.1	<0.1
2	41.90	45.43	17.97	<0.1	4.21	<0.1	<0.1
3	67.29	11.05	4.38	13.37	<0.1	3.59	<0.1
4	0.35	<0.1	<0.1	<0.1	<0.1	<0.1	<0.1
5	22.75	5.32	3.31	6.63	2.77	0.28	<0.1
6	27.87	25.70	5.36	15.48	1.55	<0.1	<0.1
7	106.00	28.34	13.24	3.09	0.28	<0.1	<0.1
8	44.61	10.33	20.10	8.41	<0.1	<0.1	<0.1
9	47.99	29.36	10.25	0.17	<0.1	<0.1	<0.1
10	50.44	25.74	13.46	0.15	<0.1	<0.1	<0.1
11	50.91	24.92	14.19	0.24	<0.1	<0.1	<0.1
12	48.88	28.27	10.60	0.19	<0.1	<0.1	<0.1
13	46.30	33.25	15.13	15.22	0.47	0.42	<0.1
14	56.33	42.80	15.18	17.70	<0.1	<0.1	<0.1
15	50.44	25.74	13.46	0.15	<0.1	<0.1	<0.1
16	51.38	24.21	14.90	0.12	<0.1	<0.1	<0.1
17	49.34	27.62	11.31	0.31	<0.1	<0.1	<0.1
18	50.91	24.92	14.19	0.24	<0.1	<0.1	<0.1
19	53.33	21.02	18.42	0.18	<0.1	<0.1	<0.1
20	55.05	18.28	18.34	0.23	0.16	<0.1	<0.1
21	58.34	22.78	0.78	0.35	<0.1	<0.1	<0.1
22	51.38	24.21	14.90	0.12	<0.1	<0.1	<0.1
23	49.97	26.55	12.75	0.12	<0.1	<0.1	<0.1
24	47.99	29.36	10.25	0.17	<0.1	<0.1	<0.1

TABLE VIII
RECTIFIER OPERATION STATUS IN CASE 3

Hour	P _{term} (MW)	Q _{term} (MVar)	V _{dc} (pu)	I _{dc} (A)	α (Deg)	T (pu)
1	44.69	13.42	1.11	129	5.00	1.09
2	50.20	16.00	1.12	145	5.00	1.10
3	40.35	11.93	1.07	121	5.00	1.05
4	35.62	9.56	1.11	104	5.00	1.08
5	43.59	13.60	1.08	130	6.08	1.06
6	46.67	14.32	1.11	135	5.00	1.09
7	44.69	13.42	1.11	129	5.00	1.09
8	54.99	18.51	1.11	160	5.00	1.10
9	56.28	19.22	1.11	164	5.00	1.10
10	58.22	20.32	1.10	170	5.00	1.10
11	58.48	20.55	1.10	171	5.39	1.10
12	56.94	19.58	1.10	166	5.00	1.10
13	55.63	18.93	1.10	162	5.00	1.10
14	46.07	14.05	1.11	133	5.00	1.09
15	58.22	20.32	1.10	170	5.00	1.10
16	58.87	20.68	1.10	172	5.00	1.10
17	57.20	19.77	1.11	166	5.28	1.10
18	58.48	20.55	1.10	171	5.39	1.10
19	60.09	21.35	1.10	176	5.00	1.10
20	59.33	20.86	1.10	173	5.00	1.10
21	56.80	19.45	1.11	165	5.00	1.10
22	58.87	20.68	1.10	172	5.00	1.10
23	57.84	20.15	1.10	169	5.30	1.10
24	56.28	19.22	1.11	164	5.00	1.10

TABLE IX
INVERTER OPERATION STATUS IN CASE 3

Hour	P_{term} (MW)	Q_{term} (MVar)	V_{dc} (pu)	I_{dc} (A)	α (Deg)	T (pu)
1	-44.14	10.16	-1.10	129	5.00	1.12
2	-49.51	12.10	-1.10	145	5.00	1.13
3	-39.86	9.01	-1.06	121	5.00	1.07
4	-35.26	7.68	-1.10	104	5.00	1.12
5	-43.03	11.03	-1.07	130	6.08	1.09
6	-46.07	10.84	-1.10	135	5.00	1.13
7	-44.14	10.16	-1.10	129	5.00	1.12
8	-54.14	14.00	-1.09	160	5.00	1.12
9	-55.40	14.53	-1.09	164	5.00	1.12
10	-57.26	15.36	-1.08	170	5.00	1.12
11	-57.52	15.45	-1.08	171	5.39	1.12
12	-56.03	14.80	-1.09	166	5.00	1.12
13	-54.76	14.31	-1.09	162	5.00	1.11
14	-45.49	10.63	-1.10	133	5.00	1.12
15	-57.26	15.36	-1.08	170	5.00	1.12
16	-57.89	15.63	-1.08	172	5.00	1.11
17	-56.29	14.89	-1.09	166	5.28	1.12
18	-57.52	15.45	-1.08	171	5.39	1.12
19	-59.07	16.13	-1.08	176	5.00	1.11
20	-58.35	15.76	-1.09	173	5.00	1.12
21	-55.90	14.70	-1.09	165	5.00	1.12
22	-57.89	15.63	-1.08	172	5.00	1.11
23	-56.91	15.16	-1.09	169	5.30	1.12
24	-55.40	14.53	-1.09	164	5.00	1.12

TABLE X
CONTROL STRATEGIES FOR DC TRANSMISSION SYSTEM IN CASE 3

Hr.	Rectifier				Inverter			
	First Control		Second Control		First Control		Second Control	
	Mode	Value	Mode	Value	Mode	Value	Mode	Value
1	CFA	5.00 Deg	CTR	1.09 pu	CC	129 A	CV	-1.10 pu
2	CFA	5.00 Deg	CTR	1.10 pu	CC	145 A	CV	-1.10 pu
3	CFA	5.00 Deg	CTR	1.05 pu	CC	121 A	CV	-1.06 pu
4	CFA	5.00 Deg	CTR	1.08 pu	CC	104 A	CV	-1.10 pu
5	CC	130 A	CV	1.08 pu	CAE	6.08 Deg	CP	-43.03MW
6	CFA	5.00 Deg	CTR	1.09 pu	CC	135 A	CV	-1.10 pu
7	CFA	5.00 Deg	CTR	1.09 pu	CC	129 A	CV	-1.10 pu
8	CFA	5.00 Deg	CTR	1.10 pu	CC	160 A	CV	-1.09 pu
9	CFA	5.00 Deg	CTR	1.10 pu	CC	164 A	CV	-1.09 pu
10	CFA	5.00 Deg	CTR	1.10 pu	CC	170 A	CV	-1.08 pu
11	CC	171 A	CP	58.48MW	CAE	5.39 Deg	CV	-1.08 pu
12	CFA	5.00 Deg	CTR	1.10 pu	CC	166 A	CV	-1.09 pu
13	CFA	5.00 Deg	CTR	1.10 pu	CC	162 A	CV	-1.09 pu
14	CFA	5.00 Deg	CTR	1.09 pu	CC	133 A	CV	-1.10 pu
15	CFA	5.00 Deg	CTR	1.10 pu	CC	170 A	CV	-1.08 pu
16	CFA	5.00 Deg	CTR	1.10 pu	CC	172 A	CV	-1.08 pu
17	CC	166 A	CP	57.20MW	CAE	5.28 Deg	CV	-1.09 pu
18	CC	171 A	CV	1.10 pu	CAE	5.39 Deg	CP	-57.52MW
19	CFA	5.00 Deg	CTR	1.10 pu	CC	176 A	CV	-1.08 pu
20	CFA	5.00 Deg	CTR	1.10 pu	CC	173 A	CV	-1.09 pu
21	CFA	5.00 Deg	CTR	1.10 pu	CC	165 A	CV	-1.09 pu
22	CFA	5.00 Deg	CTR	1.10 pu	CC	172 A	CV	-1.08 pu
23	CC	169 A	CV	1.10 pu	CAE	5.30 Deg	CP	-56.91MW
24	CFA	5.00 Deg	CTR	1.10 pu	CC	164 A	CV	-1.09 pu

The control mode at hours 2-4 is the same as that at hour 1. At hour 5, neither the rectifier firing angle nor the inverter extinction angle reaches its minimum. According to Rules 1 and 2, the rectifier would maintain CC=130 A. The second rectifier control mode is CV=1.08 pu. At this hour, the first inverter control mode is CAE=6.08 Deg and its second control mode is CP=-43.03 MW. The alternative second inverter control modes are CTR=1.09 pu or CV=-1.07 pu.

Case 4: Using the UC results in Table III, the system state can be transferred from base case to a new state in the event of line 2-3 outage (CTGL2-3) without any changes in UC. Only the generating unit dispatch is changed in accordance with (30). This is a controllable contingency and only corrective actions (changing the generation dispatch based on units physical ramping) are required in real time to mitigate violations. The total operating cost is \$64,849.43 which is higher than that without the contingency (Case 1).

Case 5: If CTGL2-3 occurs in the AC/DC transmission system described in Case 2, the system security would not be satisfied based on the UC results in Table V. The bus mismatches at hours 3,4, and 6 cannot be eliminated by only changing the generation dispatch (corrective actions). Consequently, 3 Benders cuts (42) are generated to change the UC results. In this case, generating unit 3 is committed (preventive actions) at hours 3,4 and 6 to satisfy the system security in the event of CTGL2-3. In Table XI, the UC changes in comparison to that in Case 3 are shown in bold. The total operating cost increases to \$64,269.91.

Case 6: In this case, we run the SCUC when the DC system is a fixed injection at buses 1 and 5 at all hours. We also assume that the power factor at rectifier and inverter terminals is 0.98 and the DC line has no losses. Fig. 6 shows the total operating cost when the DC transmission system is modeled with different injections between 30 MW and 55 MW. It is obvious that the proposed model would result in lower costs. There is no feasible SCUC solution when power flow injections are smaller than 30 MW or higher than 55 MW.

TABLE XI
UC IN CASE 5

Unit	Hours (1-24)
1	1 1
2	1 1
3	1 1
4	1 1 1 0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1
5	0 0 0 0 0 0 0 1 1 1 1 1 1 1 0 1 1 1 1 1 1 1 1 1

Fig. 6. Total generation costs for DC system with fixed injections

B. IEEE 118- Bus System

We consider a modified IEEE 118-bus system shown in Fig. 7 to study the proposed model. This system has 54 units, 186 branches, 14 capacitors, 9 tap-changing transformers, and 91 demand sides. The peak load of the system is 6000 MW that

occurs at hour 21. The 118-bus system data are given at <http://motor.ece.iit.edu/DC/CSC/IEEE118.xls>.

Fig. 7. IEEE 118-bus system

The following cases are tested.

Case 0: Base case without transmission constraints

Case 1: SCUC solution with AC transmission constraints

Case 2: SCUC solution when the AC line 32-113 is replaced with a two-terminal DC transmission system. The rectifier terminal is connected to bus 113 and the inverter terminal to bus 32 with the same parameters as those in Table C.6. This DC system is installed in the congested area based on SCUC results obtained in Case 1. The congested area is highlighted in Fig. 7.

The operating cost of UC in Case 0 is \$1,727,170 which increases to \$1,732,274 when the AC transmission constraints are considered in Case 1. The additional \$5,103.64 cost is mainly due to the congestion of AC line 23-32 at peak hours which causes the commitment of expensive units. Case 2 replaces the AC line 32-113 with a two-terminal DC transmission line which results in an operating cost of \$1,729,950. The DC transmission flow has decreased the transmission congestion cost of AC line 23-32 from \$5,103.64 to \$2,780 when it transfers more power from bus 113 to bus 32. In Case 2, at the peak hour, the flow on DC transmission line 32-113 increases to 38.22 MW in comparison to 3 MW in Case 1.

Fig. 8. Total hourly nodal mismatch in case 2

Fig. 8 shows the convergence results for Case 2 at hours 6 and 20. Here additional iterations are required for SCUC to converge at higher load hours (11 iterations at hour 20) as compared to those at low-load hours (3 iterations at hour 6).

V. CONCLUSIONS

In this paper, controllable DC transmission systems are modeled in SCUC along with AC transmission systems. Benders decomposition is applied to effectively handle both AC and DC transmission constraints. The SCUC solution determines the optimal selection of DC control strategies and optimal hourly DC transmission schedule at the minimum cost while maintaining the system security. A set of optimal controls for DC transmission systems can successfully mitigate the AC transmission flow congestion and enhance power system economics. We compared the proposed model with a simplified DC transmission system model with fixed power flow injections/withdrawals that was widely used in SCUC. The simplified DC model may not provide a feasible SCUC solution while the proposed SCUC model guarantees the convergence. The test results also indicate that a given UC solution for an AC transmission system may not result in a feasible once the AC lines are partly replaced by DC lines. Additional adjustments in UC and ED, and transmission control are needed to ensure the feasibility.

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Appendix A: Base for Per Unit Values

The base values for AC/DC transmission systems are listed in Table A.1.

TABLE A.1
AC AND DC BASE VALUES

AC Base	DC Base
V_{base} (kV)	$V_{dc,base} = \frac{3\sqrt{2}}{\pi} V_{base}$ (kV)
S_{base} (MVA)	$P_{dc,base} = V_{dc,base} I_{dc,base} = S_{base}$ (MW)
$I_{base} = \frac{S_{base}}{\sqrt{3}V_{base}}$ (kA)	$I_{dc,base} = \frac{\pi}{\sqrt{6}} I_{base}$ (kA)
$Z_{base} = \frac{V_{base}^2}{S_{base}} = \frac{V_{base}}{\sqrt{3}I_{base}}$ (Ω)	$Z_{dc,base} = \frac{V_{dc,base}}{I_{dc,base}} = \frac{18}{\pi^2} Z_{base}$ (Ω)
	$X_{c,base} = \frac{6}{\pi} Z_{base}$ (Ω)

Appendix B: AC/CSC-DC Jacobian Matrices

Reference [21] provides the Jacobian matrices **J1** and **J2** related to the AC system. The non-zero elements of Jacobian

matrix **J1** related to the DC transmission system are

$$\begin{aligned}
 \frac{\partial \Delta P_m}{\partial V_{dc,h}} &= -I_{dc,h}, & \frac{\partial \Delta P_m}{\partial I_{dc,h}} &= -V_{dc,h}, & \frac{\partial \Delta Q_m}{\partial V_{dc,h}} &= -I_{dc,h} \tan \phi_h \\
 \frac{\partial \Delta Q_m}{\partial I_{dc,h}} &= -V_{dc,h} \tan \phi_h, & \frac{\partial \Delta Q_m}{\partial \phi_h} &= -V_{dc,h} I_{dc,h} \left(\frac{1}{\cos \phi_h^2} \right) \\
 \frac{\partial \Delta R1_h}{\partial V_m} &= \begin{cases} -T_h \cos \alpha_h & \text{for rectifier} \\ +T_h \cos \alpha_h & \text{for inverter} \end{cases} \\
 \frac{\partial \Delta R1_h}{\partial V_{dc,h}} &= 1, & \frac{\partial R1_h}{\partial I_{dc,h}} &= \begin{cases} -X_{c,h} & \text{for rectifier} \\ +X_{c,h} & \text{for inverter} \end{cases} \\
 \frac{\partial \Delta R1_h}{\partial T_h} &= \begin{cases} +V_m \cos \alpha_h & \text{for rectifier} \\ -V_m \cos \alpha_h & \text{for inverter} \end{cases} \\
 \frac{\partial \Delta R1_h}{\partial \alpha_h} &= \begin{cases} +T_h V_m \sin \alpha_h & \text{for rectifier} \\ -T_h V_m \sin \alpha_h & \text{for inverter} \end{cases} \\
 \frac{\partial \Delta R2_h}{\partial V_m} &= \begin{cases} -0.995 T_h \cos \phi_h & \text{for rectifier} \\ +0.995 T_h \cos \phi_h & \text{for inverter} \end{cases}, & \frac{\partial \Delta R2_h}{\partial V_{dc,h}} &= 1 \\
 \frac{\partial \Delta R2_h}{\partial T_h} &= \begin{cases} -0.995 V_m \cos \phi_h & \text{for rectifier} \\ +0.995 V_m \cos \phi_h & \text{for inverter} \end{cases} \\
 \frac{\partial \Delta R2_h}{\partial \phi_h} &= \begin{cases} +0.995 T_h V_m \sin \phi_h & \text{for rectifier} \\ -0.995 T_h V_m \sin \phi_h & \text{for inverter} \end{cases}
 \end{aligned}$$

The partial derivatives of $\Delta R3_h$ depend on the of the DC configuration. For example, the partial derivatives of $\Delta R3_h$ for the two-terminal DC system shown in Fig. 5 are

$$\begin{aligned}
 \frac{\partial \Delta R3_1}{\partial I_{dc,1}} &= 1, & \frac{\partial \Delta R3_1}{\partial V_{dc,1}} &= -\frac{1}{R_{dc}}, & \frac{\partial \Delta R3_1}{\partial V_{dc,2}} &= -\frac{1}{R_{dc}} \\
 \frac{\partial \Delta R3_2}{\partial I_{dc,2}} &= 1, & \frac{\partial \Delta R3_2}{\partial V_{dc,1}} &= -\frac{1}{R_{dc}}, & \frac{\partial \Delta R3_2}{\partial V_{dc,2}} &= -\frac{1}{R_{dc}}
 \end{aligned}$$

where the subscribe 1 represents the rectifier, 2 for the inverter. Similarly, since the elements of Jacobian matrix **J3** depend on the DC configuration, we list non-zero elements of **J3** for the two-terminal DC transmission system shown in Fig. 5 as

$$\begin{aligned}
 \frac{\partial \Delta PL_{dc,1-2}}{\partial V_{dc,1}} &= I_{dc,1}, & \frac{\partial \Delta PL_{dc,1-2}}{\partial I_{dc,1}} &= V_{dc,1} \\
 \frac{\partial \Delta PL_{dc,2-1}}{\partial V_{dc,2}} &= -I_{dc,2}, & \frac{\partial \Delta PL_{dc,2-1}}{\partial I_{dc,2}} &= -V_{dc,2}
 \end{aligned}$$

where the subscribe 1 represents the rectifier, 2 for the inverter. The elements of Jacobian matrix **J4** are listed as,

$$\frac{\partial \Delta P_{term,h}}{\partial V_{dc,h}} = I_{dc,h}, \quad \frac{\partial \Delta P_{term,h}}{\partial I_{dc,h}} = V_{dc,h}$$

Appendix C: IEEE 14-Bus System Data

TABLE C.1 UNIT DATA

Unit	Bus No.	Bid (\$/MW)	Pmin (MW)	Pmax (MW)	Qmin (MVar)	Qmax (MVar)	Min On/Off (h)
1	1	8	50	150	-100	100	1
2	2	10	20	50	-50	50	1
3	3	18	12	80	-60	100	1
4	6	25	10	45	-30	30	1
5	8	40	10	45	-30	30	1

TABLE C.2 BUS DATA

Bus No.	Min Voltage (pu)	Max Voltage (pu)	Bus No.	Min Voltage (pu)	Max Voltage (pu)
1	1.04	1.07	8	1.02	1.10
2	1.03	1.05	9	1.00	1.03
3	1.00	1.02	10	1.00	1.05
4	1.00	1.03	11	0.98	1.05
5	1.00	1.04	12	1.04	1.07
6	1.05	1.10	13	1.01	1.07
7	1.01	1.05	14	0.98	1.07

TABLE C.3 AC BRANCH DATA

Line No.	From Bus	To Bus	R (pu)	X (pu)	Charging Shunt (pu)	Flow Limit (MW)
1	1	2	0.0194	0.0592	0.0264	50
2	1	5	0.0540	0.2230	0.0246	65
3	2	3	0.0470	0.1980	0.0219	60
4	2	4	0.0581	0.1763	0.0187	60
5	2	5	0.0570	0.1739	0.0170	60
6	3	4	0.0670	0.1710	0.0173	60
7	4	5	0.0134	0.0421	0.0064	40
8	4	7	0.0000	0.2091	0.0000	65
9	4	9	0.0000	0.5562	0.0000	40
10	5	6	0.0000	0.2520	0.0000	65
11	6	11	0.0950	0.1989	0.0000	50
12	6	12	0.1229	0.1558	0.0000	50
13	6	13	0.0662	0.1303	0.0000	50
14	7	8	0.0000	0.1762	0.0000	50
15	7	9	0.0000	0.1100	0.0000	30
16	9	10	0.0318	0.0845	0.0000	50
17	9	14	0.1271	0.2704	0.0000	50
18	10	11	0.0821	0.1921	0.0000	50
19	12	13	0.2209	0.1999	0.0000	50
20	13	14	0.1709	0.3480	0.0000	50

TABLE C.4 DISTRIBUTION FACTORS OF LOADS AT DIFFERENT BUSES

Load	At Bus	MW Load Factor	MVar Load Factor
1	2	0.0838	0.1728
2	3	0.3637	0.2585
3	4	0.1846	-0.0531
4	5	0.0293	0.0218
5	6	0.0432	0.1020
6	9	0.1139	0.2259
7	10	0.0347	0.0789
8	11	0.0135	0.0245
9	12	0.0236	0.0218
10	13	0.0521	0.0789
11	14	0.0575	0.0680

TABLE C.5 HOURLY LOAD DISTRIBUTION

Hour	MW	MVar	Hour	MW	MVar
1	181.30	51.45	13	207.20	58.80
2	170.94	48.51	14	196.84	55.86
3	150.22	42.63	15	227.92	64.68
4	103.60	29.40	16	233.10	66.15
5	129.50	36.75	17	220.15	62.48
6	155.40	44.10	18	230.51	65.42
7	181.30	51.45	19	243.46	69.09
8	202.02	57.33	20	253.82	72.03
9	212.38	60.27	21	259.00	73.50
10	227.92	64.68	22	233.10	66.15
11	230.51	65.42	23	225.33	63.95
12	217.56	61.74	24	212.38	60.27

TABLE C.6 CONVERTER DATA FOR THE DC TRANSMISSION SYSTEM

Type	x_c (pu)	$\alpha_{\min}$ (Deg)	$\alpha_{\max}$ (Deg)	$V_{dc, \min}$ (pu)	$V_{dc, \max}$ (pu)	Min Tap	Max Tap
Rec.	0.126	5	30	0.95	1.20	0.9	1.1
Inv.	0.175	5	30	0.90	1.10	0.9	1.5

TABLE C.7 DC BUS DATA FOR THE DC TRANSMISSION SYSTEM

Bus No.	Min Voltage (pu)	Max Voltage (pu)
1	0.95	1.20
2	0.90	1.10

TABLE C.8 DC BRANCH DATA

Line No.	From DC Bus	To DC Bus	R (pu)	Flow Limit (MW)
1	1	5	0.0342	65

Transmission Congestion Analysis in the Eastern Interconnection using POMS

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Abstract—A methodology based on the security-constrained unit commitment (SCUC) is applied to analyze the transmission congestion in the Eastern Interconnection of the United States for 2008 and 2018. The proposed SCUC tool for this study is referred to as the POMS (Power Market Simulator). The identified congestions are visualized along with the Geographical Information System (GIS) data and compared with the results published by the U.S. Department of Energy’s National Electric Transmission Congestion Study (NETCS) in 2006. The POMS study also provides the locational marginal price (LMP) information in the Eastern Interconnection, which is not available in the NETCS report. The POMS simulation results for representing congested branches and LMPs could be applied to the future transmission expansion planning studies.

Index Terms—Transmission Congestion, SCUC, LMP, National Electric Transmission Congestion Study, Eastern Interconnection in the United States

I. INTRODUCTION

THE identification of possible congestion sites is the first step in any grid expansion and reinforcement studies. The Federal Power Act (FPA) 216(a) resulted in a study of the electric transmission congestion in the United States [1]. The first congestion study report, known as the National Electric Transmission Congestion Study (NETCS) and issued in August 2006, identified congestions and constraints in the Eastern and the Western Interconnections [2]. The NETCS report included the review of the available information on historical congestion, the simulation of future congestions, and the comparison of simulation results with the historical information. Another published report analyzes the available 2007 data for assessing the transmission congestion in the Eastern Interconnection [3]. For the purpose of comparison, this paper will focus on the NETCS in 2006.

This paper focuses on the congestion studies in the Eastern Interconnection of the U.S. by applying SCUC. In addition, the congestion and LMP results are visualized along with the GIS data. The rest of this paper is organized as follows. Section II describes the proposed methodology for identifying congestions and presents the congestion study results for the Eastern Interconnection in 2008 and 2018. The study results of 2008 are also compared with the results in the NETCS report. Section III concludes this paper.

II. METHODOLOGY FOR IDENTIFYING CONGESTION

A. Congestion Simulation

The tool used for this study is called Power Market

Simulator (POMS), which has been used extensively for power system studies for decades. The methodology in POMS simulates the hourly electricity market operation based on SCUC for identifying possible congestions¹. The POMS simulation results have several advantages over those of the optimal power flow (OPF). A POMS simulation study considering the commitment and the redispatch of generating units will provide a more realistic picture of possible scenarios. In essence, it may be necessary to consider potential changes in the hourly unit commitment to satisfy certain constraints.

The POMS applications to the Eastern Interconnection simulation consider a decomposition and coordination strategy shown in Fig. 1. A similar procedure is followed for considering contingencies [4]–[7].

Fig. 1 SCUC Solution for the Eastern Interconnection

In this section, we utilize POMS to simulate the congestions in the Eastern Interconnection based on the 2008 and 2018 data. We compare the POMS simulation results with those in the NETCS report, referred to as NETCS results thereafter, and analyze the variations in the POMS simulation results from 2008 to 2018. Note that there are about 70,000 branches at all voltage levels in the Eastern Interconnection. We consider in the POMS simulation only those branches that are above 200kV along with 1,000 flowgates.

B. POMS Simulation Results for 2008

In this case, POMS is applied to simulate the 8,760 hours of generation dispatch and transmission flows in the Eastern Interconnection in 2008. The pertinent definitions are provided in Appendix A.

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¹ The congestion in this paper is defined as a state in which the flow on a branch has reached the branch capacity.

B1) Transmission Congestions based on the Binding Hours Metric

The POMS simulation results show that in 2008 there are 1,325 congested branches², 270 of which are congested in all hours. The most congested branches are in the New York and the Chicago regions. There are also several congested branches in the boundary between Georgia and Florida. Fig. 2 shows the zoomed-out version of the congested branches based on the binding hours metric.

B2) Constrained Branches based on the U90 Hours Metric

As expected, more transmission branches are constrained based on the U90 hours metric. There are 2,497 U90 branches³, 483 of which are continuously loaded above 90% of their capacities. The U90 branches are again concentrated in the New York region, the Chicago region, and the boundary between Georgia and Florida. Fig. 3 shows the zoomed-out version of constrained branches based on the U90 hours metric.

Fig. 2 Binding Hours Information in 2008

Fig. 3 U90 Hours Information in 2008

B3) Number of Constrained Branches

Fig. 4 shows the number of constrained branches as a percentage of time. There are 1,325 congested branches and 439 (i.e. 33%) of these branches are congested in more than

80% of the annual hours and 600 (i.e. 45%) are congested in less than 20% of the annual hours. The U90 curve in Fig. 4 has a similar trend except that more branches are constrained based on the U90 metric. It is expected that more branches would be constrained if U75 was used as the metric.

Fig. 4 Constrained Branches as a Function of Time in 2008

B4) Locational Marginal Prices

Fig. 5 shows the 2008 annual average LMPs based on the POMS simulation results. The New York region shows the highest LMPs in the Eastern Interconnection because of its limited generation capacity. Due to the existing transmission congestions, much of the low cost power from neighboring regions cannot be transmitted to the New York region. So, the LMPs in the New York region are high due to its dependence on local expensive units such as gas units and oil units for supplying the local load. The LMPs in New England and Florida are relatively high for similar reasons. Even though the Chicago region also exhibits transmission congestion, the LMPs are not as high which is partly due to the cheap coal-fired and nuclear power generation close to the load centers. Large wind developments in the Midwest could provide large sums of low cost energy to the Midwest energy markets. So, LMPs in the northwest region of the Midwest are relatively low.

Fig. 5 Annual Average of LMPs in 2008

B5) Cost of Served Load and Congestion Cost

Based on the 2008 POMS simulation, the total cost of served load is about \$172.3 billion. The total congestion cost is about \$13 billion which is about 7.5% of the total cost of served load. The total production cost is about \$75.3 billion. Fig. 6 shows that the production cost as a function of the

² A congested branch is a branch with a non-zero binding hour.

³ A U90 branch is branch with a non-zero U90 hour.

hourly load. A higher production cost would appear in hours 5000-5500 (July and August), which are consistent with higher loads experienced during this time.

Fig. 6 Production Cost in 2008

C. POMS Simulation Results for 2018

The Eastern Interconnection is simulated in 2018 using POMS. The input data are based on the forecasts in the MISO MTEP 2008 study [8]. The loads are assumed to increase at an annual rate of 1.0128% based on the 2008 loads. The fuel prices are assumed to increase at an annual escalation rate of 4% for oil and gas, 2% for coal, and 3% for nuclear fuels. The transmission and generation projects that are under construction or are planned by 2018 in the Eastern Interconnection are incorporated in the 2018 simulation. New England and Florida, which were not included in the MISO MTEP 2008 study, are excluded from the POMS simulation.

C1) Transmission Congestion based on the Binding Hours Metric

The simulated 2018 congestion is shown in Fig. 7. There are 2,665 branches that are congested for at least one hour and 314 of those branches are always congested in 2018. Most of the congested branches are in the New York and the PJM interconnections. Certain branches in the west side of the SERC region are also congested.

Fig. 7 Binding Hours Information in 2018

C2) Constrained Branches based on the U90 Hours Metric

Fig. 8 shows constrained branches based on the U90 metric. There are 4,239 constrained branches based on U90 and 472 of those branches are continuously loaded in excess of 90% of their capacities. Such branches are mainly located in New York and in certain parts of the PJM system (including Chicago). A few branches are also constrained in the west side of the SERC region.

Fig. 8 U90 Hours Information in 2018

C3) Number of Constrained Branches

Fig. 9 shows the number of constrained branches as a percentage of time. Out of 2,665 branches that are congested in at least one hour, 524 (i.e. 20%) remain congested in at least 80% of the annual hours and 1,599 (i.e., 60%) are congested in less than 20% of the annual hours. Based on the U90 metric, there are 4,239 branches that are constrained, 710 (i.e., 15%) of such branches remain constrained in at least 80% of annual hours, and 2,715 (i.e., 65%) are constrained in less than 20% of the annual hours. The two curves have similar trends except that more branches are constrained based on the U90 metric.

Fig. 9 Constrained Branches as a Function of Time in 2018

C4) Locational Marginal Prices

The annual average LMPs based on the 2018 simulation are shown in Fig. 10. New York has the highest LMPs in the Eastern Interconnection. The LMPs in the East Coast are generally higher than those in other regions. High LMPs are also encountered in Louisiana and Mississippi indicating transmission congestions. LMPs in Illinois and Indiana are lower than those in the East Coast because there are cheap

coal-fired and nuclear power plants close to load centers. LMPs in the Northwest region of the Midwest are significantly lower than those in other regions due to expected high penetration of wind power.

Fig. 10 Annual Average LMPs in 2018

C5) Cost of Served Load and Congestion Cost

The total cost of served load in 2018 is about \$230.9 billion and the total congestion cost is about 10% of the total cost of served load. The total production cost in 2018 is \$83.6 billion with the hourly costs shown in Fig. 11, where higher hourly production costs appear in July and August.

Fig. 11 Production Cost in 2018

D. Comparison of POMS and NETCS Results in 2008

In this section, we compare the 2008 POMS simulation results with the NETCS results. The NETCS report reviewed the historical congestions and analyzed the 2008 congestion in the Eastern Interconnection using the optimal power flow (OPF) model [2].

D1) Regional Congestion

The POMS and the NETCS simulation results show that congestions are concentrated in the New York and the PJM regions (including Chicago). In addition, congestions are identified at the border between Georgia and Florida. With high LMPs in Florida, the cheaper energy is imported to the state which leads to congestions at the border. These congestions were not presented in the review of historical information in the NETCS report because the actual transactions between Florida and Georgia are based on long

term contracts which would limit the power flow across the Georgia-Florida border.

D2) Number of Congested Paths/Branches

In NETCS, 58 historically congested paths were identified with the detailed geographical information given in [2]. In the simulation results presented in NETCS, 171 congested transmission paths were identified in 2008. In comparison, the POMS simulation results for 2008 identified 270 congested branches that always constrained based on the binding hours metric. The difference is due to the fact that one transmission path in the NETCS report may represent several branches although the details are not given in the NETCS report.

One notable point is that both the NETCS and the POMS simulation results identify more congestions than what is reported by the historical data. This is due to the assumption in both simulations that economic transactions occur whenever is possible. A two-bus example presented in the Appendix B illustrates how economic transactions could cause additional congestions. It should be pointed out that almost all historical congestions have also been identified in the NETCS simulation results and the POMS simulation results.

D3) Constrained Transmission Capacities

Fig. 12 shows the percentage of constrained transmission capacity as a function of time and Fig. 13 shows the constrained capacity (GW) as a function time in 2008. In particular, it is shown in Fig. 12 that about 23% of the constrained transmission capacity is congested more than 80% of the annual hours based on the Binding Hours curve, and about 30% of the constrained transmission capacity is constrained more than 80% of annual hours based on the U90 Hours curve. Note that the U90 branches will always include the congested branches and that is why the U90 Hours curve is above the Binding Hours curve in Figs. 12 and 13.

In NETCS, heavy congestion occurs in only a few hours per year. For instance, 80% of the congestion occurs for less than 20% of the annual hours [2]. In comparison, the POMS simulation results in Fig. 12 show more congestion. In the latter case, 50% of the congestion occurs in less than 20% of the annual hours.

Fig. 12 Constrained Transmission Capacity (%) as a function of Time in 2008

Fig. 13 Constrained Transmission Capacity (GW) as a function of Time in 2008

This difference can be attributed to the differences in the input data and the modeling details. For instance, both branch flowgate limits are taken into account in the POMS simulation, while only branch limits are monitored in the NETCS. In addition, the NETCS was completed in 2006. Thus, some transmission projects that were completed since then might not be included in the NETCS simulation. It is also possible that certain transmission projects that were assumed in the NETCS are not built and thus not included in the simulation in this paper.

In Fig. 12, the two curves coincide beyond the 60% constrained transmission capacity point, i.e., about 40% of constrained transmission capacity is constrained less than 10% of the time. The difference between the two curves is more obvious in Fig. 13. 228 GW of transmission capacity is congested based on Binding Hour metric and 588 GW is congested based on the U90 Hour metric.

Fig. 14 also shows the constrained transmission capacity as a function of time. However, only the congested transmission branches are considered in calculating the constrained transmission capacity in both cases. In contrast to Fig. 12, the two curves in Fig. 14 are more distinguishable. For instance, 40% of the congested transmission capacity is congested as least 40% of the binding time. The same transmission capacity will be loaded to 90% or more at 70% of the time.

Fig. 14 Constrained Transmission Capacity as a function of Time in 2008 (congested capacity is used as base)

D4) Congestion Costs

In the POMS simulation results for 2008, the total cost of served load is \$172.3 billion and the congestion cost is about 7.5% of the total cost. In comparison, in the NETCS report, the total cost of served load is about \$171 billion and the

congestion cost is about 4.7% of the total cost. That is, the total costs in two cases are almost the same but the POMS simulation results show more congestion. Fig. 15 shows the relationship between the congestion cost and the constrained transmission capacity for the POMS simulation in 2008 and 2018. For the 2008 case, 20% of the constrained transmission capacity accounts for about 73% of the total congestion cost and 50% of the constrained transmission capacities account for 97% of the total congestion cost. For the 2008 case in the NETCS report, 20% of the constrained transmission capacity accounts for 60% of the total congestion cost and 50% of the constrained transmission capacity accounts for 95% of the total congestion cost [2]. The POMS simulation results are similar to those of the NETCS in this case.

The POMS simulation results in Fig. 15 also show that the congestion cost is caused by a small number of constrained branches. The POMS results are similar to the NETCS results. Since the congestion cost is ultimately passed through to consumers, this also means that the planning of a relatively small number of transmission projects along constrained transmission paths could lead to a significant reduction in congestion costs and introduce a major economic benefit to consumers.

Fig. 15 Congestion Cost and the Constrained Transmission Capacity

E. Comparison of POMS Results in 2008 and 2018

In this section, we compare the POMS simulation results for 2008 and 2018.

E1) Locational Marginal Prices

Figs. 5 and 10 show that LMPs in 2018 are higher than those in 2008. In fact, the average load-weighted LMP in the Eastern Interconnection increases from \$48.85/MWh in 2008 to \$65.93/MWh in 2018. The higher LMPs could be attributed to increasing loads and fuel prices.

E2) Production and Congestion Costs

The total production cost in 2008 is about \$75.3 billion as compared to \$83.6 billion in 2018. The hourly production costs in 2018 (Fig. 11) and 2008 (Fig. 6) are similar. In both cases, higher production costs appear in the summer months (July and August). As expected, the hourly production costs in 2018 are higher than those in 2008 due to the load growth and fuel price escalations. Even though the New England and the Florida are not considered in the 2018 simulation, the total cost of served load increases from \$172.3 billion in 2008

to \$230.9 billion in 2018. It is interesting to note that the total cost of served load increases by 34% while the total production cost increases by 11%. This phenomenon can be explained using a two-bus example presented in Appendix C.

The congestion cost as a percentage of the cost of supplying the load increases from 7.5% in 2008 to 10% in 2018, which shows that the system is more congested in 2018 due to the load growth and higher fuel prices. The results would also point out that sufficient generation and transmission projects investments may not have been planned within the 10-year period.

Fig. 15 shows that the 2018 curve is a little higher than the 2008 curve, 20% of the congested transmission capacity accounts for about 73% of the total congestion cost in 2008 while 20% of the congested transmission capacity accounts for 83% of the total congestion cost in 2018. This means that congestion costs are more concentrated on a small percentage of constrained transmission capacity in 2018 than in 2008. Fig. 15 also shows that 50% of the congested transmission capacity accounts for 97% of the total congestion cost in 2008 and that 50% of the congested transmission capacity accounts for 98% of the total congestion cost in 2018. This means that the congestion cost is attributed to half of the congested capacity. In Fig. 15, the two curves almost coincide above the 50% of congested transmission capacity, which shows that the other 50% of the congested transmission capacity has very small impact on the congestion cost in both 2008 and 2018.

E3) Constrained Transmission Capacity as a Function of Time

Fig. 16 shows the percentage of constrained transmission capacity as a function of time. Fig. 17 shows the MW constrained transmission capacity as a function of time in 2018. In 2018, about 549GW of transmission capacity is congested, 4.9% of which is continuously congested and 66% is congested less than 20% of the time in one year. Based on the U90 metric, about 944GW of the transmission capacity is constrained, about 5.4% of which is constrained continuously in one year. In 2008, 228GW of transmission capacity is congested, about 11% of which is congested continuously for the entire year and 50% is congested less than 20% of the time in one year. Based on the U90 metric, about 588GW transmission capacity is constrained in 2008, about 15% of which is constrained continuously for the entire year.

In Fig. 16, the two curves are closer in comparison to Fig. 12. This means that the transmission capacities that are identified as constrained by the U90 metric would be more often constrained in 2018 than in 2008. In Fig. 16, the two curves coincide beyond the 40% constrained transmission capacity which account for about 15% of the time, so about 60% of constrained transmission capacity is constrained only in a few hours for the one year. Again we see that the congestion would be more confined to a small percentage of constrained transmission capacities in 2018 as compared with those in 2008.

Fig. 16 Constrained Transmission Capacity as a Function of Time in 2018

Fig. 17 Percent of Time and Constrained Transmission Capacity in 2018

III. CONCLUSIONS

In this paper, a SCUC methodology is proposed in POMS for the congestion analysis in the U.S. Eastern Interconnection for 2008 and 2018. The POMS simulation results are compared with those in the NETCS report. The simulation results are integrated with GIS data to offer a comprehensive and intuitive understanding of transmission constraints and LMPs. We envision that the proposed POMS methodology and the result can provide valuable information for transmission expansion studies.

APPENDIX

A. Congestion Metrics

In NETCS, five metrics were defined to assess the magnitude of transmission congestion, including binding hours, U90, all-hour shadow prices, binding hour shadow prices, and congestion rents. The metrics used in this paper include binding hours, U90 hours, constrained transmission capacity, LMPs, cost of served load, and congestion cost.

1) Binding Hours and U90 Hours

Those branches on which the flows have reached their limits are identified as congested branches. In addition, branches with flows above 90% of the flow limits are identified as U90 branches. In this paper, two congestion metrics including the binding hours and the U90 hours [2] [9] are defined as follows which are based on a long term (e.g., 8,760 hours) POMS simulation.

$$\text{Binding hours of branch } l = \sum_{t=1}^{NT} x_{l,t} \quad (1)$$

$$x_{l,t} = \begin{cases} 1 & \text{if branch } l \text{ is congested at period } t \\ 0 & \text{otherwise} \end{cases}$$

$$\text{U90 hours of branch } l = \sum_{t=1}^{NT} y_{l,t} \quad (2)$$

$$y_{l,t} = \begin{cases} 1 & \text{if branch } l \text{ is loaded above 90\%} \\ & \text{of its capacity at period } t \\ 0 & \text{otherwise} \end{cases}$$

where NT represents the number of time periods (e.g., 8,760). These two definitions are similar to those in the NETCS report.

Similar to U90 hours, other metrics such as U75 hours or U60 hours can also be defined in order to assess the degree of congestion. These metrics can be used to classify and rank the identified congestions.

2) Constrained Transmission Capacity

The constrained transmission capacity of a system is the sum of the transmission capacity of all branches that are constrained at least in one hour during the study horizon. The constrained transmission capacity could be different when different congestion metrics are used, e.g., binding hours and U90 hours. If binding hours is applied to identify congestions, the constrained transmission capacity is formulated as follows.

$$\text{Constrained transmission capacity} = \sum_{l=1}^{NB} z_{l,1} * PL_{l,\max}$$

$$z_{l,1} = \begin{cases} 1 & \text{if binding hours of branch } l > 0 \\ 0 & \text{if binding hours of branch } l = 0 \end{cases} \quad (3)$$

where NB represents the number of branches and $PL_{l,\max}$ is the capacity of branch l . Similarly, if U90 hours is applied to identify congestions, the constrained transmission capacity is formulated as follows.

$$\text{Constrained transmission capacity} = \sum_{l=1}^{NB} z_{l,2} * PL_{l,\max}$$

$$z_{l,2} = \begin{cases} 1 & \text{if U90 hours of branch } l > 0 \\ 0 & \text{if U90 hours of branch } l = 0 \end{cases} \quad (4)$$

3) LMPs

LMPs at individual buses are calculated as part of the outputs from the SCUC based simulation. Since LMP differences in a system are caused by congestions, an LMP map would provide an intuitive way of visualizing congestions across the system. LMP information is not discussed in the NETCS report.

4) Cost of Served Load

The cost of served load is the total payment made by all loads in the system, which is calculated as,

$$\text{Cost of served load} = \sum_{t=1}^{NT} \sum_{j=1}^{ND} LMP_{j,t} * D_{j,t} \quad (5)$$

where ND represents the number of load buses; $LMP_{j,t}$ represents the LMP of load bus j at period t ; $D_{j,t}$ represents

the load at bus j at period t .

5) Congestion Cost

The congestion cost was calculated as the increase in the production cost due to the re-scheduling of units to alleviate congestions [10]. In this paper, the congestion cost is defined as the difference between the load payment and the generation credit based on LMPs,

$$\text{Congestion cost} = \sum_{t=1}^{NT} \sum_{j=1}^{ND} LMP_{j,t} * D_{j,t} - \sum_{t=1}^{NT} \sum_{i=1}^{NG} LMP_{i,t} * P_{i,t} \quad (6)$$

where NG represents the number of generator buses; $LMP_{i,t}$ represents the LMP at generator bus i at period t ; $P_{i,t}$ represents the generation at bus i at period t .

The congestion cost metric defined as (6) is similar to the congestion rent defined in the NETCS report [2]. Congestion cost as a percentage of the cost of served load could indicate the magnitude of congestion of the entire system.

B. Congestion Analysis

The one-line diagram of a two-bus system with two generators and two loads is shown in Fig. 18. G1 and L1 are located at Bus 1 and G2 and L2 are located at Bus 2. The capacities for both generators are 800MW and the incremental cost is 10\$/MWh for G1 and 20\$/MWh for G2. L1 is 400MW and L2 is 600MW. Bus 1 and Bus 2 are connected through one transmission line with a capacity of 300MW. In the ideal case, G1 and G2 will be dispatched to 700MW and 300MW, respectively. The economic transaction between Bus 1 and Bus 2 will be 300MW. Accordingly, the flow on the line will be 300MW, which makes the line congested. However, if we intentionally limit the transaction between Bus 1 and Bus 2 to 100MW, there will be no congestion on the line. This shows that economic transactions could cause congestions that are not present without the economic transactions

Fig. 18 Two-Bus System

C. Operation and Congestion Costs Analysis

The system is the same as the two-bus system in B. We assume the L1 is 250MW and L2 is 250MW at first. So the system will have no congestion. All the loads will be supplied by G1 and the production cost is \$5,000 and the cost of served load is \$5,000. If L1 and L2 are both increased by 50MW, the power flow on the transmission line will reach its limit 300MW). G2 will be the marginal generator at Bus 2 and the LMP at Bus 2 will be \$20/MWh. The production cost

is \$6,000, and the cost of served load is \$9,000. That is, the production cost increases by about 20% and the cost of served load increases by about 80% owing to the growth of loads.

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Investigation into Use of PMSG-based Wind Farm for Grid Support

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Abstract—Reliability and quality of the electrical power supply is of great importance for all grids. A well designed wind farm can help balancing the unpredictable power changes caused by the load-side of the grid. This paper offers some simulation tests on using PMSG-based direct drive wind turbine generator with full scale back-to-back converters for grid support. Different cases have been presented to show that wind energy could be an efficient back-up plan for voltage regulation and a brief study has been carried out which concentrates on possible dynamic compensation on improving the frequency stability of the grid.

Index Terms—dynamic compensation, full scale converters, PMSG, reactive power, short term voltage stability

I. INTRODUCTION

BECAUSE of higher and steadier wind speed, offshore wind turbines could generate more power with more reliability. Larger turbine size, less limits on shipping and erection and the closeness to the coastal centers of the nations, indicate offshore wind farm inevitably will become a vital part of wind energy. EU leads the world's offshore wind power capacity with 2,063 MW installed, and it is expected to reach 40 GW or more by 2020 (EWEA target) [1]. For US, the 420 MW Cape Wind project off the Massachusetts coast has won final approval in April 2010, and there are many projects at different stages of development, including in the Great Lakes [2].

With advances in technology, modern wind turbine generators are capable of responding positively to the network disturbances instead of being unable to respond to the changes in system situation or even aggravating the network's status. Considering the capability of operation under fault condition and the steadiness of functioning for long-time period, direct-drive wind turbine technology goes ahead of the contest with DFIG. For offshore wind farms, maintenance factor (especially on gearbox part) prevents DFIG to become the first choice. Among the direct-drive wind turbines generators, the one with permanent magnet synchronous generator (PMSG) has become prevalent in the recent years. For PMSG, no additional power supply is needed for the field

excitation and the absence of mechanical components such as slip rings brings higher reliability for generator itself. [3]

To control PMSG at variable speed situation, control of d and q components of the current to control the electromagnetic torque at the generator-side converter and active and reactive power decoupled control at the grid-side converter is proposed [4]. The capability of PMSG-based wind turbine generator to operate uninterruptedly during grid faults, with chopper at DC-link, under different control strategy for converters is tested [5, 6]. Direct-drive wind turbine generator with full scale converters has gained the capability to finish low-voltage ride through process and supply reactive power to the grid [5, 6]. For voltage regulation, a supervisory reactive power control strategy has been proposed on wind-turbine-infinite-bus model [7]. It is found that under this control, both active and reactive power outputs respond very fast in face of solid fault or load changes. However, contribution of the offshore wind farm to voltage and frequency stability of a system other than one connected to infinite bus has not been done yet.

In this paper: system voltage unstable condition cases due to large disturbances (grounded fault) are examined and then the same cases with wind energy support would be studied for comparison. For active power dynamic compensation study, same comparison strategy would be proposed. The simulation tests for all cases in this paper would be implemented with Matlab/Simulink.

II. PMSG-BASED WIND TURBINE GENERATOR WITH FULL SCALE BACK-TO-BACK CONVERTER MODEL AND CONTROL

A. Wind Turbine Model

The input wind power of the wind turbine could be defined as:

$$P_{wind} = \frac{1}{2} \rho A v_{wind}^3 = \frac{1}{2} \rho \pi \left(\frac{D}{2}\right)^2 v_{wind}^3 \quad (1)$$

Where ρ is the air density, A is the blade swept area, D is the blade diameter and v_{wind} is the mean value of measured wind speed.

The mechanical power of the turbine is [8]:

$$P_m = \frac{1}{2} \rho \pi \left(\frac{D}{2}\right)^2 v_{wind}^3 C_p \quad (2)$$

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Where C_p is turbine efficiency in converting wind energy to mechanical energy.

B. Permanent Magnet Synchronous Generator (PMSG) model

The dynamic model of PMSG in the d-q reference frame is as follows:

$$L_d \frac{d}{dt} i_d = u_d - R i_d + L_q \omega_e i_q \quad (3)$$

$$L_q \frac{d}{dt} i_q = u_q - R i_q - L_d \omega_e i_d - \psi \omega_e \quad (4)$$

$$T_e = \frac{1}{2} p [\psi i_q + (L_d - L_q) i_d i_q] \quad (5)$$

Where L_d and L_q are d and q axis inductances, R is resistance of the stator windings, i_d and i_q are d and q axis currents, u_d and u_q are d and q axis voltages, ω_e is electrical rotating angular velocity of the rotor, ψ is the amplitude of the flux induced by the permanent magnets of the rotor in the stator phases, p is number of pole pairs, and T_e is electromagnetic torque [9].

In this dynamics model of PMSG, back electromotive force (back EMF) is assumed to be sinusoidal in the stator. The mechanical system of PMSG can be expressed as:

$$J \frac{d\omega}{dt} = T_m - F\omega - T_e \quad (6)$$

$$\frac{d\theta}{dt} = \omega \quad (7)$$

Where J is the combined inertia of rotor and wind turbine, F is the combined viscous friction of rotor, wind turbine and load, θ is rotor angular position, T_m is the shaft mechanical torque [9].

C. Generator-side Converter Control

Since the PMSG-based wind turbine is equipped with full scale back-to-back converter, ther, the AC power generated by PMSG is converted into DC form through the generator-side converter.

To control stator d-q current components, Constant Torque Angle Control (CTA) is used in this study. CTA keeps the torque angle constant at 90 degrees, causing the stator current vector on q-axis [10]. Therefore, the electromagnetic torque would depend on the magnitude of q-axis current component exclusively. Subsequently, the electromagnetic torque produced by PMSG could be simplified as:

$$T_e = \frac{3}{2} p i_q \quad (8)$$

The current components could be controlled to control the voltage components in (3), (4). This leads to the generator-side converter control strategy with Field Oriented Control (FOC) scheme [10]. The control strategy of generator-side converter is shown in the following figure:

Fig. 1 Generator-side converter control strategy

Where:

$$\begin{aligned} \text{cmp}_1 &= L_d \omega_e i_q + \psi \omega_e + R i_d \\ \text{cmp}_2 &= -L_q \omega_e i_d + R i_q \end{aligned} \quad (9)$$

D. Grid-side Converter Control

One objective of controlling of grid-side converter is to keep the DC-link voltage constant regardless of amount of power produced by the generator [11]. The dynamic model of the grid-connected inverter in d-q reference frame rotating at ω_g could be shown to be:

$$\begin{aligned} u_d &= u_{id} - R i_{id} - L \frac{d}{dt} i_d + L \omega_g i_q \\ u_q &= u_{iq} - R i_{iq} - L \frac{d}{dt} i_q - L \omega_g i_d \end{aligned} \quad (10)$$

If the q-axis voltage component could be adjusted to be zero, which is [4]:

$$u_{grid} = u_d + j0 \quad (11)$$

Then, the active and reactive power injected into the network could be represented as:

$$\begin{aligned} P &= \frac{3}{2} u_d i_d \\ Q &= \frac{3}{2} u_d i_q \end{aligned} \quad (12)$$

Therefore, the independent control of active and reactive power could be achieved by controlling the d-q axis current components. The control strategy of grid-side converter is shown as follows:

Fig. 2 Grid-side converter control strategy

Where:

$$\begin{aligned} \text{cmp}_1 &= u_d + \omega_g L q^i - R i_d \\ \text{cmp}_2 &= \omega_g L i_q + R i_q \end{aligned} \quad (13)$$

III. SYSTEM DESCRIPTION

The study power system is a 3-generator-8-bus system with offshore wind farm integrated. Total generation capacity for traditional synchronous generators is 426MW, wind farm generation supply is 81MW (wind energy penetration level is around 16% for simulation). Onshore transmission voltage level is 230kV and connection between onshore system and offshore wind farm is HVAC submarine cable operated on the voltage level of 132kV. The receiving end of HVAC submarine cable is bus #8. The load side voltage levels are 10kV and 25kV for constant load (static model) and industrial load.

Fig. 3 8-bus system and Wind Farm Integrated into the System with Submarine Cable

IV. SIMULATION RESULTS

To study voltage (reactive power) support capability of the wind farm, a self clearing fault is applied in the system and stability of the system with and without reactive power support from the wind farm is compared. Some of the cases on voltage stability analysis are as follows:

Case 1: Three-phase symmetrical solid fault at bus #7 at $t = 1.5s$ cleared at $t = 1.57s$ ($\Delta t = 0.07s$, 4 cycles). Load center at bus#8.

The load at bus #8 consists of constant PQ load (10MW/10Mvar) and industrial load (modeled as an induction motor with 212MW rated power, voltage stability is load-driven stability based on the published literature [12, 13] and induction motor is widely used as the model of industrial

load for voltage stability studies.), which is about 44% of the total load (507MW). Loads at other buses are only constant PQ load. In this case, the load center (at bus #8) is located very close to the offshore wind farm. For reactive power support, the following control block would be used for grid-side converter.

Fig. 4 q-axis current component reference generator of wind farm for voltage regulation

Fig.5 Voltage magnitudes of buses #8, #2, #5 and #7, dotted red lines correspond to no support from the wind farm, blue lines show the improvement due to wind farm support

Fig. 6 Power output of wind farm and rotor speed of induction motor at bus #8, dotted red lines correspond to no support from the wind farm, blue lines show the improvement due to wind farm support

This case shows that without wind farm support voltages will not be recovered, whereas with wind farm support they

are recovered in 0.83 seconds. Therefore, wind farm support preserves voltage stability of the network. For wind farm, the reactive power output increased to about 0.6 p.u during the fault, attaining its original values once the voltages recovered. The rotor speed of the induction motor at bus #8 had a slight drop and back to its normal level.

Case 2: Three-phase symmetrical solid fault at bus #7 at $t = 1.5s$ cleared at $t = 1.57s$ ($\Delta t = 0.07s$, 4 cycles). Load center at bus#5.

Bus #5 is relatively far away from wind energy POI. The load at bus #5 consists of constant PQ load (10MW/10Mvar) and industrial load (modeled as an induction motor with 229MW rated power), which is 47% of the total load (507MW).

Fig. 8 Voltage magnitudes of buses #2, #5, bus #7 and #8, dotted red lines correspond to no support from the wind farm, blue lines show the improvement due to wind farm support

Fig. 7 Power output of wind farm and rotor speed of induction motor at bus #8, dotted red lines correspond to no support from the wind farm, blue lines show the improvement due to wind farm support

It can be seen in this case that voltages will not be recovered without wind farm support, whereas with wind farm support they are recovered in 1.03 seconds. Therefore, wind farm support preserves voltage stability of the network.

For wind farm, the reactive power output increased to about 0.6 p.u during the fault, attaining its original values once the voltages recovered. The rotor speed of the induction motor at bus #5 had a slight drop and back to its normal level.

Case 3: Three-phase symmetrical solid fault at $t = 1.5s$ cleared at bus #7 at $t = 1.58s$ ($\Delta t = 0.08s$, 5 cycles), wind farm would participate in reactive power support when fault happened

The following figures demonstrate the voltage changes for both scenarios where load center located at bus #8 and at bus #5 scenarios.

Fig. 9 Voltage magnitudes of buses #2, #5, #7 and #8, load center at bus #8

Fig.10 Voltage magnitudes of buses #2, #5, #7 and #8, load center at bus #5

For both scenarios, the voltage magnitudes did not go back to acceptable values even with wind farm support and the system lost its voltage stability.

For dynamic active power compensation study, a large disturbance is introduced into the grid causing large magnitude low frequency oscillation. To mitigate the oscillation, wind farm would adjust its active power output for compensation and the following control scheme would be imposed on grid-side converter control:

Figure. 11 Active power output control mechanism

Generator #3 would be tripped at $t = 6s$ and remain off line, generator #1 and #2 would pick-up the lost power output.

The results for two cases, with and without wind farm dynamic support are demonstrated as follows:

Fig. 12 System frequency after disturbance with and without wind farm compensation

Fig. 13 System Active Power after disturbance with and without wind farm compensation

Figure. 14 Wind farm active power output after disturbance with and without wind farm compensation

Figure. 15 Wind farm DC-link voltage magnitude after disturbance with and without wind farm compensation

Wind farm active power output is almost constant when it does not participate in dynamic compensation. When wind farm does participate in dynamic compensation, its active power output remains constant for the first half second after the disturbance, as it is producing its maximum power, and then it dips for about half a second due to control action. The energy stored during this time period will peak afterwards. DC-link voltage undergoes a sharp increase due to the reduction of active power output at grid-side and a rapid drop to release the stored energy into the grid.

V. CONCLUSION

According to the simulation results for short-term large-disturbance wind energy grid-support studies, conclusions could be made as followed:

Based on the test cases, wind energy reactive power compensation did make some contributions to grid support on voltage stability improvement. However, reactive power compensation from wind power will not be a vital countermeasure but a back-up plan if large disturbance like solid fault is encountered. The distances between the load center and wind farm would not make a large impact on

voltage stability improvement when large disturbance happens.

With the support from wind farm, oscillation in the system due to large disturbance is mitigated and the system frequency stability is improved. Due to the equipments' physical restriction, the power unbalance condition between DC and AC side of the converters should not last for too long and the power surge at DC side should be limited to a tolerable range. This means active power output reduction at the wind farm is limited.

Fast response of the power electronics in wind turbine generator and flexible control schemes show superiority of wind turbine generator in participating in more system regulations in the future.

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Investigation of Possible Dynamic Interaction between DFIGs of Different Capacity Operating in the Same Wind Farm

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Abstract- This paper explores the possibility of dynamic interaction between DFIGs of different capacity in a grid connected and islanding mode wind farm. The modeling of DFIG is presented in the paper. The case of adding 5 MW DFIGs to a wind farm with existing 1.5 MW DFIGs is considered. Grid-connected scenario is considered regarding the connection of the units. Moreover, step-up wind speed and fault at infinite bus will be introduced as disturbances to examine the possible dynamic interaction. Simulation using MATLAB and Simulink has been used to investigate all cases. To further justify the simulation results, a series of modal small perturbation analysis is also conducted.

Index Terms--DFIG, dynamic interaction, grid-connected, system modeling, modal analysis

I. INTRODUCTION

IN the last 10 years, the capacity of installed global wind farm has been growing at a rate of around 30% per year. Wind power is playing an increasingly significant role in global energy supply. Five types of wind turbine generators (WTG) have been employed in wind farms [1]. Among these, the Doubly Fed Induction Generator (DFIG) is currently the most efficient and therefore the most popular one. The biggest advantage of DFIG is its capability in decoupling control of active and reactive power while the machine is able to run asynchronously.

Regarding the dynamic interaction research on DFIG, there are some papers focusing on dynamic interaction of DFIG and other power sources, such as [2] which investigates the influence of DFIG control on wind farm stability and the interaction between the wind farm and power system, and [3] which simulates the dynamic interaction of DFIG and fuel cell with the AC grid. In [4], the eigenvalue analysis method is applied to observe the dynamic interaction between DFIG and synchronous generator. There are still no studies on the dynamic interaction between DFIGs of different capacity. Nowadays, the manufacture of DFIG with large capacity is developing rapidly and subsequently the capacity expansion of existing DFIG based wind farms with units of much larger capacity becomes more and more realistic. Therefore, the

importance and necessity of research into the dynamic interaction between DFIGs of different capacity has emerged.

To investigate this dynamic interaction, 5 MW DFIGs are added to a wind farm with existing 1.5 MW DFIG. For the grid connection case, sets of 5 MW and 1.5 MW DFIGs connected to infinite bus via a transmission line distributed by step-up wind speed and fault at infinite bus is simulated. The performances of 1.5 MW and 5 MW DFIGs wind farms in changing wind conditions are studied by observing their outputs of active power, reactive power, stator current and rotor speed. The responses of these two DFIGs to the faults are analysed and examined as well. A modal small signal analysis is implemented for observing the dynamic interaction by building system differential equations and obtaining eigenvalues.

II. DOUBLY-FED INDUCTION GENERATOR DYNAMIC MATHEMATICAL MODEL

A. DFIG Configuration

The configuration of DFIG shown in Fig. 1, consists of induction generator, wind turbine, drive train, rotor-side control, grid-side control and pitch control.

Fig. 1. Configuration of a Grid-Connected Wind Turbine Double-fed Induction Generator

B. Modeling of the Induction Generator

The electrical part of the machine is represented by a fourth-order state-space model [5]. All electrical variables and parameters are referred to the stator. This is indicated by the prime signs in the machine equations given below (1)~(4). All

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stator and rotor quantities are in the arbitrary two-axis reference frame (d/q frame).

$$V_{qs} = R_s \cdot i_{qs} + \frac{d\varphi_{qs}}{dt} + \omega \cdot \varphi_{ds} \quad (1)$$

$$V_{ds} = R_s \cdot i_{ds} + \frac{d\varphi_{ds}}{dt} - \omega \cdot \varphi_{qs} \quad (2)$$

$$V_{qr} = R_r \cdot i_{qr} + \frac{d\varphi_{qr}}{dt} + (\omega - \omega_r) \cdot \varphi_{dr} \quad (3)$$

$$V_{dr} = R_r \cdot i_{dr} + \frac{d\varphi_{dr}}{dt} - (\omega - \omega_r) \cdot \varphi_{qr} \quad (4)$$

C. Modeling of Wind Turbine Aerodynamics

The mechanical power extracted from the wind could be obtained by [6]:

$$P_m = \frac{1}{2} \rho A_r v_w^3 C_p \quad (5)$$

where ρ is the air density in kg/m^3 ; $A_r = \pi R^2$ is the area swept by the rotor blades in m^2 ; C_p is power coefficient; λ is tip-speed-ratio; and β is the blade pitch angle. $C_p(\lambda, \beta)$ can be calculated as:

$$C_p = C_1 \left(\frac{c_2}{\lambda + c_8\beta} - \frac{c_2 c_9}{\beta^3 + 1} - C_3\beta - C_4\beta^5 - C_6 \right) \cdot e^{-\left(\frac{c_7}{\lambda + c_8\beta} - \frac{c_7 c_9}{\beta^3 + 1} \right)} + C_{10}\lambda \quad (6)$$

where $C_1 \sim C_{10}$ are coefficients, and the maximum value of $C_{p-max} = 0.4382$ can be obtained by $\beta = 0$ and $\lambda = 6.325$.

D. Modeling of Drive Train

A two-mass drive train model [10] is used in this study, in which there are two separate masses to represent the low-speed turbine and the high-speed generator, and the connecting resilient shaft is modelled in (7)~(9) as a spring and a damper.

$$\frac{d}{dt} \omega_t = \frac{1}{2H_t} (T_m - T_{tg}) \quad (7)$$

$$\frac{d}{dt} \omega_m = \frac{1}{2H_g} (T_{tg} - F\omega_m - T_e) \quad (8)$$

$$T_{tg} = K_{sh}(\theta_t - \theta_m) + D(\omega_t - \omega_m) \quad (9)$$

where ω_t is the turbine speed; ω_m is the generator speed; T_m is mechanical torque applied to the turbine; T_e is electromagnetic torque of the generator; T_{tg} is the internal torque between turbine and generator; θ_t is turbine angular position; K_{sh} is the shaft stiffness; and D is the mutual damping coefficient.

E. Modeling of Rotor-Side Control

The Rotor-Side control scheme consists of two cascaded control loops [7]. The inner current control loops regulate independently the d-axis and q-axis rotor current components, i_{dr} and i_{qr} , according to some synchronously rotating

reference frame. The outer control loops govern both the stator active power (generator rotor speed) and reactive power separately. The basic rotor-side controller diagram is shown in Fig. 2.

Fig. 2. The Vector Control Scheme of Rotor-Side Control

F. Modeling of Grid-Side Control

The Grid-Side Control also consists of two cascaded control loops [7], the inner current control loops regulate independently the d-axis and q-axis GSC ac-side current components, i_{dg} and i_{qg} , in the synchronously rotating reference frame. The outer control loops regulate the dc-link voltage and the reactive power exchanged between the grid-side control and the grid.

The basic grid-side controller diagram is shown in Fig. 3.

Fig. 3. The Vector Control Scheme of Grid-Side Control

G. Design of Pitch Control

The differential equation of this pitch control [11] could be expressed as (10).

$$T \cdot \frac{d\beta}{dt} = K_{p_\beta} \cdot \frac{d\omega_r}{dt} + K_{i_\beta} \cdot \omega_{err} \quad (10)$$

Fig. 4, shows the scheme of pitch angle control loop [9];

Fig. 4. Wind Turbine Pitch Angle Controller

III. SIMULATION RESULTS

To demonstrate the possible dynamic interaction between 5 MW and 1.5 MW DFIGs, a double machine grid-connected system in Fig. 5, is built for simulation studies using Matlab/Simulink. The disturbance signals like step-up wind

input and self-clearing fault at infinite bus will be introduced into the system. The transmission line length varies in the case study to detect the effect of the distance of the wind farm from the grid on dynamic interaction. Both high and low level wind speeds are used as inputs in order to observe the potential interaction between these two DFIGs when they run both super-synchronously and sub-synchronously. The outputs of rotor speeds, active powers, reactive powers and stator currents of these two DFIGs are recorded for judging the possible dynamic interaction between them.

In Fig. 5, DFIG1 and DFIG2 represent 30 MW (6×5 MW) and 9 MW (6×1.5 MW) DFIGs respectively. The DFIG based wind farm is connected through a transmission line and a step-up transformer to an infinite bus.

Fig. 5. Two DFIG wind farms connected to infinite bus

A. Case I: Grid-connected 6×5 MW And 6×1.5 MW DFIGs With Step-up Wind Input

To observe the possible dynamic interaction between 5 MW and 1.5 MW DFIGs, 6×5 MW and 6×1.5 MW DFIGs are connected to infinite bus through a 30 km transmission line. The wind speed is assumed to be a step-up signal from 13 m/s to 15 m/s at $t = 1$ s for both wind farms. As the wind speed is above the rated value, the pitch controller is activated all the time. The RSC reactive power is regulated at $Q_s^* = 0$ and the GSC q-axis current is set at $i_{qg}^* = 0$ respectively.

The results (Fig. 6, and Fig. 7,) indicate that there is no dynamic interaction between 5 MW and 1.5 MW DFIGs. When the pitch controller is activated, the rotor speeds and active power outputs of both DFIGs are regulated at rated values. These two DFIGs are working well together under the condition of step-up winds.

Fig. 6. Step-up wind 13 to 15 m/s: rotor speed, active power output, reactive power output of 5 MW DFIG

Fig. 7. Step-up wind 13 to 15 m/s: rotor speed, active power output, reactive power output of 1.5 MW DFIG

B. Case II: Grid-connected 6×5 MW And 6×1.5 MW DFIGs Under Grid Fault With Smaller Wind Speed in Sub-synchronous State

A 100 ms three-phase short circuit is applied to the infinite bus at $t = 1$ s. In order to test the dynamic responses of 5 MW

and 1.5 MW DFIGs in sub-synchronous state, the wind speed is assumed to be 9 m/s. During pre-fault and post-fault condition, the commands of reactive power outputs and GSC q-axis current are maintained at 0 pu.

From Fig. 8, we can see 5 MW and 1.5 MW DFIGs do not oscillate against each other under all three wind speeds. The damping speed of each output varies as different winds are carried out; however, all the outputs of both DFIGs stabilize after a short while. This can prove that 5 MW and 1.5 MW DFIGs are able to work together either in sub-synchronous or super-synchronous states.

Fig. 8. Constant wind 9 m/s: rotor speeds, active power outputs and d-axis stator currents of 5 MW and 1.5 MW DFIGs

C. Case III: Grid-connected 6×5 MW And 6×1.5 MW DFIGs Under Grid Fault With Different Transmission Line Lengths

Different transmission line lengths are applied in this case, 10 km, 30 km, and 60 km. The dynamic responses of two DFIGs during and after a grid fault are presented. A 100 ms three-phase short circuit is applied to the infinite bus at $t = 1$ s. Wind speed is assumed to be 13 m/s. During pre-fault and post-fault condition, the reference values of reactive power outputs and GSC q-axis current are maintained at 0 pu.

It can be noted from Fig. 9 and 10 that, under the same wind conditions, the rotor speeds oscillation amplitudes of 5 MW and 1.5 MW DFIGs become larger as transmission line length increases, but the damping of active power outputs and stator currents turns faster. These two DFIGs can still work together very well, without sever dynamic interaction happening.

Fig. 9. Transmission line lengths 10, 30 and 60 km: rotor speeds, active power outputs and d-axis stator currents of 5 MW DFIG

Fig. 10. Transmission line lengths 10, 30 and 60 km: rotor speeds, active power outputs and d-axis stator currents of 1.5 MW DFIG

IV. MODAL ANALYSIS

To further justify the results of case study, a set of dynamic equations of double machine grid-connected system is established for small signal modal analysis. If all the eigenvalues are located on the left half of the complex plane, the equilibrium point selected is stable [4] and therefore, no dynamic interaction between 5 MW and 1.5 MW DFIGs can be determined.

For system small signal stability analysis, an equivalent circuit with equivalent voltage sources is built in a d-q reference frame [5]. The generator stator and rotor voltage equations (1)-(4) can be derived as the differential equations (11)-(14) of stator current and equivalent voltage behind transient impedance as state variables [12]-[4]-[8].

$$\frac{1}{\omega_b} \frac{di_{ds}}{dt} = -\frac{\omega_s}{X'_s} \left(R_s + \frac{X_s - X'_s}{\omega_s T_0} \right) i_{ds} + \omega_s i_{qs} + \frac{\omega_r}{X'_s} e'_{ds} - \frac{1}{X'_s T_0} e'_{qs} + \frac{\omega_s L_m}{X'_s L_r} v_{dr} - \frac{\omega_s}{X'_s} v_{ds} \quad (11)$$

$$\frac{1}{\omega_b} \frac{di_{qs}}{dt} = -\omega_s i_{ds} - \frac{\omega_s}{X'_s} \left(R_s + \frac{X_s - X'_s}{\omega_s T_0} \right) i_{qs} + \frac{1}{X'_s T_0} e'_{ds} + \frac{\omega_r}{X'_s} e'_{qs} + \frac{\omega_s L_m}{X'_s L_r} v_{qr} - \frac{\omega_s}{X'_s} v_{qs} \quad (12)$$

$$\frac{1}{\omega_b} \frac{de'_{ds}}{dt} = -\frac{1}{T_0} [e'_{ds} - (X_s - X'_s) i_{qs}] + (\omega_s - \omega_r) e'_{qs} - \frac{\omega_s L_m}{L_r} v_{qr} \quad (13)$$

$$\frac{1}{\omega_b} \frac{de'_{qs}}{dt} = -\frac{1}{T_0} [e'_{qs} + (X_s - X'_s) i_{ds}] - (\omega_s - \omega_r) e'_{ds} - \frac{\omega_s L_m}{L_r} v_{dr} \quad (14)$$

where L_r is stator voltage vector $v_s = v_{ds} + jv_{qs}$; rotor voltage vector $v_r = v_{dr} + jv_{qr}$; $X_s = \omega_s / L_s$; $X'_s = \omega_s (L_s - L_m^2 / L_r)$; $T_0 = L_r / R_r$. ω_b is frequency base. The equivalent circuit of grid-connected two DFIGs system can be presented as the graphic below:

Fig. 11. Equivalent Circuit of Two DFIGs Connected to a Grid

By adding differential equations of grid-side converter and two-mass drive train (7)-(9), we can obtain a set of differential equations to present simplified grid-connected double DFIG wind turbines system. Performance of 5 MW and 1.5 MW DFIG wind turbine under small perturbation in a grid-connected mode is studied by substituting corresponding equilibrium points.

A. Modal Analysis Case I: Grid-connected 6×5 MW And 6×1.5 MW DFIGs at Wind Speed 13m/s in Super-synchronous states

TABLE I
EIGENVALUES FOR 5 MW DFIG AT $V_w = 13\text{m/s}$, $\Omega_r = 1.2$ PU

Eigenvalues of 5 MW DFIG	Damping Ratio	State Variables
$-109.35 \pm j578.44$	0.186	i_{ds}, i_{qs}
$-22.53 \pm j376.00$	0.060	e'_{ds}, e'_{qs}
$-22.52 \pm j316.08$	0.071	i_{dg}, i_{qg}
$-27.46 \pm j341.04$	0.080	ω_r, θ_t
-1.28	1	ω_t

TABLE II
EIGENVALUES FOR 1.5 MW DFIG AT $V_w = 13\text{m/s}$, $\Omega_r = 1.2$ PU

Eigenvalues of 1.5 MW DFIG	Damping Ratio	State Variables
$-87.08 \pm j547.09$	0.157	i_{ds}, i_{qs}
$-18.36 \pm j311.43$	0.059	e'_{ds}, e'_{qs}
$-15.98 \pm j355.09$	0.045	i_{dg}, i_{qg}
$-22.33 \pm j345.66$	0.065	ω_r, θ_t
-0.04	1	ω_t

From Table I and II, the eigenvalues of all the state variables of both 5 MW and 1.5 MW DFIGs are negative, There is no direct coupling happening between these two DFIGs' rotor speeds or turbine speeds. It can be proved that the generator and wind turbine systems of these two DFIGs do not have dynamic interaction.

B. Modal Analysis Case II: Grid-connected 6×5 MW And 6×1.5 MW DFIGs at Wind Speed 9 m/s in Sub-synchronous states

TABLE III
EIGENVALUES FOR 5 MW DFIG AT $V_w = 9\text{m/s}$, $\Omega_r = 0.972$ PU

Eigenvalues of 5 MW DFIG	Damping Ratio	State Variables
$-109.31 \pm j578.44$	0.186	i_{ds}, i_{qs}
$-22.53 \pm j376.00$	0.060	e'_{ds}, e'_{qs}
$-22.46 \pm j316.10$	0.071	i_{dg}, i_{qg}
$-27.40 \pm j341.05$	0.080	ω_r, θ_t
-1.35	1	ω_t

TABLE IV
EIGENVALUES FOR 1.5 MW DFIG AT $V_w = 9\text{M/S}$, $\Omega_r = 0.982\text{ PU}$

Eigenvalues of 1.5 MW DFIG	Damping Ratio	State Variables
$-87.03 \pm j547.10$	0.157	i_{ds}, i_{qs}
$-18.29 \pm j311.43$	0.059	e'_{ds}, e'_{qs}
$-15.98 \pm j355.11$	0.045	i_{dg}, i_{qg}
$-22.28 \pm j345.67$	0.065	ω_r, θ_t
-0.04	1	ω_t

Compared this result to modal analysis Case I, we can find that as wind speed changes, the eigenvalues of stator currents, equivalent voltages and grid-side converter currents barely move. Two DFIGs of different capacity can still work together in sub-synchronous states.

C. Modal Analysis Case III: Grid-connected $6 \times 5\text{ MW}$ And $6 \times 1.5\text{ MW}$ DFIGs at Wind Speed 13 m/s With Transmission Line Length at 60 km

TABLE V
EIGENVALUES FOR 5 MW DFIG AT $V_w = 13\text{M/S}$, $\Omega_r = 1.2\text{ PU}$, $L = 60\text{KM}$

Eigenvalues of 5 MW DFIG	Damping Ratio	State Variables
$-210.75 \pm j720.02$	0.280	i_{ds}, i_{qs}
$-43.21 \pm j373.85$	0.115	e'_{ds}, e'_{qs}
$-36.06 \pm j299.06$	0.120	i_{dg}, i_{qg}
$-24.42 \pm j239.68$	0.101	ω_r, θ_t
-0.65	1	ω_t

TABLE VI
EIGENVALUES FOR 1.5 MW DFIG AT $V_w = 13\text{M/S}$, $\Omega_r = 1.2\text{ PU}$, $L = 60\text{KM}$

Eigenvalues of 1.5 MW DFIG	Damping Ratio	State Variables
$-163.74 \pm j671.10$	0.237	i_{ds}, i_{qs}
$25.52 \pm j334.30$	0.076	e'_{ds}, e'_{qs}
$-27.83 \pm j308.92$	0.090	i_{dg}, i_{qg}
$-14.98 \pm j222.54$	0.067	ω_r, θ_t
-0.96	1	ω_t

Most state variables of both two DFIGs have their eigenvalues move left and damping ratios increase as the transmission line distance enlarges. The performances of 5 MW and 1.5 MW DFIGs in the same wind farm are rarely affected by the transmission line distance to the grid.

V. CONCLUSION

Doubly-fed induction wind turbine generators of different capacity have good performance in grid connected mode when some disturbances are introduced to the system. The good fault-ride through capability is shown when 5 MW and 1.5 MW DFIGs are working together within the same wind farm.

There is little dynamic interaction emerging between 5 MW and 1.5 MW DFIGs. In the condition of step-up wind input, both DFIGs adapt the abrupt input change and are able to maintain the stable power outputs and rotor speed after a short term adjustment. Under faults, both DFIGs manage to be stable during post-fault period. They are demonstrated to be able to work perfectly together either sub-synchronously or super-synchronously by introducing different levels of wind speeds. The length of transmission line isn't a problem for both 5 MW and 1.5 MW DFIGs.

The modal small signal system analysis helps to explore the dynamic characteristics of double DFIGs grid-connected mode more intuitively. It can be justified that there is no direct coupling between the drive train systems of 5 MW and 1.5 DFIGs as well as their generators. Both DFIGs have negative eigenvalues for all the state variables when they work together.

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