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WEATHERING THE COLD OF '94

**A Review of the January 1994
Energy Supply Disruptions
in the Eastern United States**

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May 1995
U.S. Department of Energy

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May 1995
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Executive Summary

During the week of January 16–22, 1994, very low temperatures over a wide region of the Eastern United States caused unprecedented sustained demand for energy. Notably,

- At least 37 electric utilities experienced record winter peak demands on January 18 or 19.
- Many natural gas pipelines that supply the Eastern United States shipped record amounts of natural gas.

The January 1994 weather conditions were more severe and more widespread geographically than any previous cold-weather episode on record and affected more utility systems than any past situation.

Low temperatures on occasion caused petroleum products to congeal in pipelines, preventing or slowing throughput. In some cases, wet or frozen coal at electric generating plants forced utilities to burn more light oil and kerosene for flame stabilization, which, in turn, created shortages of these fuels. In a few instances, electric power outages further exacerbated energy-delivery problems by de-energizing petroleum pipeline pumps and natural gas pipeline compressors needed to maximize pipeline operations. Fortunately the cold weather of January 1994 did not significantly affect

natural gas production in the major producing regions.

In addition to the severe cold, in many areas there were major snow and ice storms in the week before the extremely low temperatures. These storms that constrained highway and rail transportation, severely restricted water movements of petroleum and coal, and downed electric lines.

Compounding the problems created by extreme weather conditions and unprecedented demand for energy was the fact that the temperature drop was unexpected and sudden. The first real warning of the extreme conditions to come did not occur until January 10, when the National Weather Service predicted "much-below-normal" temperatures for the Mid-Atlantic region. These much-colder-than-normal temperatures had not been anticipated in most earlier long-term weather forecasts. Furthermore, even during January, there continued to be large deviations between forecast and actual low temperatures, and there is no indication that accuracy improved as the time between the forecast and actual date decreased.

As a result, some electric and gas utilities were unable to meet actual peak consumer demand for limited periods of time. Electric power transmission, distribution, and

generation systems were fully loaded, as were flows through natural gas pipelines. Further, the distributors supplying propane, kerosene, and fuel oil to customers with alternate-fuel capability were unable to meet all demands. Inadequate communication among utilities, the media, customers, and governmental agencies at all levels (Federal, State, and local) exacerbated the situation.

Nonetheless, energy entities responded promptly and effectively to the extreme weather and record peak demands. Electric and gas utilities demonstrated great technical skills and flexibility in implementing highly effective response actions. Despite the peak and continuing high electric load levels due to the extreme low-temperature conditions, there was no risk to the integrity of the Eastern Interconnection. The short-term use of manual load shedding (rotating blackouts) by the Pennsylvania-New Jersey-Maryland (PJM) Interconnection and the operating subsidiaries of the Virginia Electric and Power Company (Virginia Power and North Carolina Power), although it temporarily inconvenienced consumers, was appropriate and necessary to match the available supply with the continuing series of very high peak loads and hourly energy requirements.

A number of actions taken by State and local governments—including appeals for voluntary energy conservation, closing of government operations, and transportation assistance to the energy supply entities—were both appropriate and effective. Likewise, actions by the U.S. Coast Guard in the Philadelphia area to break ice and maintain shipping channels were a key element in mitigating the public

health and safety impacts of January 18, 19, and 20.

Followup investigations by several States, the electric utilities and the PJM Interconnection, the North American Electric Reliability Council (NERC), the Federal Energy Regulatory Commission (FERC), and others consistently commended energy supply entities and did not identify any specific response action as inappropriate. These same reviewers, however, identified several additional actions that could have mitigated the extent of the crisis and made the response actions more effective.

Building on and supplementing the FERC and NERC conclusions and recommendations, this report identifies the following areas in which some incremental improvements appear to be appropriate:

- Communication within the energy infrastructure
 - Energy emergency situation reporting to State and Federal agencies, for both existing and anticipated emergencies
 - Accuracy of short-term load forecasting systems used by system operators to project hourly, next-day, and 2-day peak and energy loads based on available meteorological and other relevant data
 - Specific research activities by the electric industry dealing with fuel use and electrical equipment operations in extreme cold weather and freezing precipitation
 - Timely adjustments of bulk power transfer capability
 - Regular joint planning and conduct of energy emergency preparedness exercises involving energy supply entities, States, and the Federal Government
-

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Preface

Because of the widespread energy supply and distribution problems during the extreme cold weather of January 16–22, 1994, the Department of Energy initiated a detailed review of the situation, as did the North American Electric Reliability Council, the Federal Energy Regulatory Commission, and several State emergency management offices or State regulatory agencies. The common goal was to learn what caused or exacerbated the situation and what actions were taken or could have been taken to mitigate its impacts. The approach taken in this study consisted of four parts:

- Describe the cold-weather episode in terms of service interrupted, impact on public health and safety, and resulting societal costs
- Identify the causes of the energy problems encountered
- Recognize and evaluate response actions taken by industry and by State, local, and Federal government agencies
- Identify options to reduce the vulnerability to such episodes in the future or to improve the collective ability to respond to them

The Department published a notice in the *Federal Register* on April 7, 1994, announcing its intent to examine the circumstances of electric power and

natural gas supply during the January 1994 cold-weather episode. This notice was followed by a series of letters asking for cooperation and some relevant data from the organizations most directly involved in dealing with the situation. Table P-1 lists the organizations that cooperated. The findings, conclusions, and recommendations in this report have been developed largely from material provided by these organizations.

As part of this review, events were reconstructed chronologically across geographic regions, industry organizations, and governmental entities; and interactions, dependencies, and interdependencies among them were noted and examined. Emergency protocols and their implications were also reviewed. Instances of creative cooperation were discovered that may have avoided or mitigated disruptions in supply. For example, the Pennsylvania National Guard helped with fuel deliveries by clearing roads and even transporting fuel in heavy-duty military vehicles. Conversely, this study identifies some missed opportunities for cooperation that actually may have exacerbated the public impacts of the cold weather episode. For example, during rolling blackouts in Pennsylvania, compressor stations on a natural gas pipeline lost power, limiting the flow of gas and worsening

Table P-1. Organizations Most Directly Involved in the Cold-Weather Episode of January 16-22, 1994

Electric Industry	Natural Gas Industry	Government
Electric Power	Natural Gas Associations	Federal
North American Electric Reliability Council (NERC)	American Gas Association	Department of Energy
Edison Electric Institute (EEI)	Interstate Natural Gas Association of America	Federal Energy Regulatory Commission
American Public Power Association (APPA)	Natural Gas Pipelines	Environmental Protection Agency
National Rural Electric Cooperative Association (NRECA)	Iroquois	General Services Administration
PJM Interconnection Association (PJM)	Transco	Department of Transportation
Selected PJM Utilities	Texas Eastern Transmission Co.	Office of Personnel Management
Philadelphia Electric Co.	Natural Gas Pipeline Co.	Internal Revenue Service
Public Service Electric & Gas Co.	Tenneco	Defense Fuel Supply Center (DOD)
Pennsylvania Power & Light Co.	Consolidated NG	State Government and Regulatory Agencies
Baltimore Gas & Electric Co.	Local Distribution Companies	Maryland
Potomac Electric Power Co.	West Penn Gas	Pennsylvania
Other Utilities/Power Pools	Boston Gas	New Jersey
Virginia Electric and Power Co.	Elizabethtown Gas	Delaware
Allegheny Power System, Inc.	Washington Gas	Virginia
American Electric Power Co.		Local Government Agencies
New York Power Pool		District of Columbia Energy Office
		District of Columbia Public Service Commission

an already-tight natural gas supply. Had utilities and pipeline operators communicated better, this situation could have been avoided.

This report emphasizes the interdependency of energy systems (such as the gas-supply system's use of electricity and electric utilities' need for gas, oil, and coal) and the special protocols adopted by each for emergency use. Emergency protocols for one energy form, such as electricity, are sometimes not known by suppliers of other energy forms, such as natural gas.

This report is organized into four sections, plus appendices. Section 1 presents an overview of the energy supply and demand picture during the week of January 16-22 and then

focuses on the meteorological conditions in which the energy and emergency response systems were forced to operate during the entire episode.

Section 2 discusses the effects of the weather on electric power and how the industry, States, and the Federal Government dealt with those effects. Section 3 discusses the effects of the weather on natural gas demand and supply and how the various agents dealt with those impacts. Finally, Section 4 provides some conclusions believed by the Department to be relevant to the situation and makes recommendations considered appropriate to reduce the likelihood or impact of similar occurrences in the future.

1 January 1994: Vagaries of Weather

OVERVIEW

During the week of January 16–22, 1994, very low temperatures over a wide region of the Eastern United States caused unprecedented sustained demand for all forms of energy, from New England to Tennessee and from the Atlantic Coast to Ohio and Indiana. The January 1994 weather conditions were more severe and more widespread geographically than any previous cold-weather episode on record, and therefore affected more utility systems than any past situation.

At least 37 electric utilities experienced record winter peak demands on January 18 or 19, and, in many instances, natural gas pipelines that supply the Eastern United States shipped record amounts of natural gas at the same time. Natural gas pipelines and supply entities curtailed or interrupted natural gas to large commercial and industrial customers when allowed by contractual arrangements. Electric utilities throughout the Eastern United States were affected by these gas curtailments, and began to use alternate fuels, principally light oil, with a small increase in the use of heavy oil.

Low temperatures on occasion caused petroleum products to congeal in pipelines, thereby preventing or

slowing throughput. In some cases, wet or frozen coal at electric generating plants forced utilities to burn more light oil and kerosene for flame stabilization, which, in turn, created some consumer shortages of these fuels. In a few instances, electric power outages further exacerbated energy-delivery problems by de-energizing petroleum pipeline pumps and natural gas pipeline compressors needed to maximize pipeline operations.

The extreme cold also negatively affected equipment used in substations at the terminals of bulk electric power transmission lines and at petroleum and natural gas facilities and generating stations. For example, ice may sometimes prevent high-voltage mechanical electric switches from operating.

In addition to the severe cold, in many areas there were major snow and ice storms in the week before the extremely low temperatures—storms that constrained highway and rail transportation, severely restricted water movements of petroleum and coal, and downed electric lines in southeastern Pennsylvania due to heavy ice accumulation. A heavy snow and ice storm in southeastern Pennsylvania during the second week of January created a major emergency for the PECO Energy Company, which

supplies energy for this area and the City of Philadelphia. The electric energy supply to more than a million customers was disrupted, forcing PECO Energy to implement many emergency actions, including extensive overtime for its employees.

Compounding all this was the fact that the first real warning of the extreme conditions to come did not occur until January 10, when the National Weather Service predicted "much-below-normal" temperatures for the Mid-Atlantic region. Further, the commercial meteorological services used by energy suppliers all had large deviations between forecast and actual high and low temperatures—even for 1-day projections. The extreme and sudden low temperatures significantly—and quickly—increased energy requirements, and were a major contributing factor to the January 1994 energy supply shortages. And the lack of accurate temperature projections made it difficult for utilities to make advance preparations.

These conditions—unprecedented demand, extreme conditions, and inaccurate forecasts—caused disparities between short-term peak-load forecasts and actual requirements, which resulted in the following:

- Much-greater-than-expected demand for electricity
- Higher-than-expected unavailability of generating units
- A bulk electrical power transmission system loaded to maximum capacity
- Shortages of primary fuel supplies needed to generate electricity

As a result, some electric and gas utilities were unable to meet actual

peak consumer demand for limited periods of time. Electric power transmission, distribution, and generation systems were fully loaded, as were flows through natural gas pipelines. Further, the distributors supplying propane, kerosene, and fuel oil to customers with alternate-fuel capability were unable to meet all demands. Communication difficulties among utilities, the media, customers, and governmental agencies at all levels (Federal, State, and local) exacerbated the situation.

The responses of energy suppliers varied widely, with the extreme being controlled, manually implemented, short-term (10- to 30-minute) disruptions in energy supplies in the Mid-Atlantic region and portions of Virginia and North Carolina as demand for electricity threatened to exceed available supply. All the affected utilities and control areas implemented their established emergency load curtailment plans. Actions included direct appeals to commercial and industrial customers and public appeals to all consumers to conserve energy. System voltage reductions of about 5 percent also were implemented to mitigate load requirements and preserve the integrity of the utility network. At the urging of the Potomac Electric Power Company (Pepco), which was speaking as a representative of the Pennsylvania-New Jersey-Maryland (PJM) Interconnection and the Washington Gas Light Company, the Mayor of Washington, D.C., ordered nonessential businesses and city government operations to close on Thursday, January 20. The Federal Government in Washington, D.C., closed most operations between late afternoon of January 19 and the morning of

Heating Degree-Days

The severity of the cold temperatures of January 1994 can also be described in terms of "heating degree-days"—a measure of the minimum cold temperatures, which are added to provide a cumulative total. The National Weather Service defines a heating degree-day as the number of degrees per day the daily average temperature is below 65 degrees Fahrenheit. For example, if the average temperature is 45 degrees, there would be 20 heating degree-days for that day ($65 - 45 = 20$). (The daily average temperature is the mean of the maximum and minimum hourly temperatures for a 24-hour period.)

These data are published regularly by the National Weather Service for a number of metropolitan areas around the Nation.

As shown in Table 1-1, an analysis of heating degree-days indicates that January 1994 was a relatively cold month throughout the United States and that the Mid-Atlantic region was much colder than normal. While average U.S. temperatures in January (measured in heating degree-days) were 6 percent below normal, temperatures in Richmond were 7 percent below normal; in Philadelphia, 9 percent; and in Washington, 20 percent.

Table 1-1. Heating Degree-Days, January 1994 Versus Normal January

Location	Jan 1-29, 1994	Normal for January	Percent Increase
Philadelphia International Airport	1,060	970	9.3
Washington National Airport	1,026	853	20.3
Richmond International Airport	883	822	7.4
U.S. Total*	911	858	6.2

*Excludes Alaska and Hawaii

January 21 in support of the mayor's actions. Declarations of Emergency also were issued in the District of Columbia, New Jersey, Pennsylvania, and Virginia under which government and, in some cases, commercial and industrial operations were curtailed.

INACCURATE TEMPERATURE FORECASTS

From January 16 through January 22, actual temperatures in many locations in the Mid-Atlantic area were significantly lower than projected; and, as

shown in Figure 1-1, much lower than historical levels. This figure compares normal January average minimum and maximum daily temperatures with those reported by the National Weather Service for several cities in the affected area for each of the days included in this assessment. In Philadelphia, for example, the low temperatures for 5 of the 7 days during this period ranged from -5 to +5 degrees Fahrenheit. Similar extremes extended over all the Mid-Atlantic States and the eastern area of the Nation. For example, in Pennsylvania, the following all-time record low temperatures (in degrees Fahrenheit) were set: Pittsburgh, -22 degrees; Harrisburg, -22 degrees; Scranton, -21 degrees; and Erie, -18 degrees. Harrisburg, Pennsylvania, received 14 inches of snow on January 17; and in Pittsburgh, temperatures remained below zero for 52 consecutive hours. A Pennsylvania State University meteorologist has predicted that this magnitude of cold weather should not occur in Pennsylvania for another 50 to 100 years.

These much-colder-than-normal temperatures were not expected in most long-term weather forecasts. During the fall of 1993, the National Weather Service's 30- and 90-day temperature projections expected normal and above-normal temperatures for the Eastern United States, and the National Oceanic and Atmospheric Administration's Climate Analysis Center was predicting a mild winter for the northeastern part of the country as late as November 1993. And the actual temperatures in the Eastern United States—particularly in the Mid-Atlantic region—in fact were

above normal during the fall and early winter, conforming to these projections.

Through the fall of 1993, the year had been uneventful for electric energy supply entities across the Nation. Only the Pacific Northwest region had been identified as having a potential electric power supply problem, and that was due to low levels of water in its many reservoirs. Public reports from the North American Electric Reliability Council (NERC) and some of the regional electric reliability councils all stated that no electric energy supply problems were anticipated during the 1993-94 winter; however, each of these assessments was based on normal winter weather.

The National Weather Service's 30-day temperature outlook published in late December for January was its first indication that "below-normal" temperatures were anticipated for the Mid-Atlantic States ("below normal" is a National Weather Service term for temperatures 3 to 5 degrees lower than historical norms). This temperature projection indicated "much-below-normal" temperatures (temperatures more than 5 degrees lower than historical norms) for New York and the western areas of New England. Actual temperature conditions were "much-below-normal" in the Mid-Atlantic States and "below-normal" in New York and New England. In late December, the average temperatures in the Midwest and Eastern United States dropped significantly, and there were large accumulations of ice and snow in many areas. On December 26, 1993, snow and sleet fell in most areas of the Mid-Atlantic States, and

Figure 1-1. High and Low Temperatures in Selected Cities, January 16-22, 1994, Versus Normal January Average

temperatures dropped sharply to below-normal levels. Below-normal conditions then continued for the next 2 months.

The first real warning of the serious conditions did not come until January 10, 1994, when the National Weather Service issued its 6-to-10-day temperature outlook for January 16-20, which forecast "much-below-normal" temperatures for the Mid-Atlantic region. On Tuesday, January 11, a strong cold front from Canada sent snow, sleet, and freezing rain to Southern Appalachia; a second front sent snow, sleet, rain, and freezing rain over the Mid-Atlantic States and New England.

However, there continued to be large deviations between forecast and actual low temperatures, and there is no indication that accuracy improved as the time between the forecast and actual date decreased. Figure 1-2, which is based on data supplied by the Potomac Electric Power Company, illustrates this situation. The figure shows that the January 15 low-temperature forecast for Washington, D.C., for Tuesday, January 18, was 18 degrees. On January 16th, this low-temperature forecast was reduced to 11 degrees, and on January 17 to

7 degrees. On January 18, it was increased to 11 degrees. The actual low temperature on January 18 was 2 degrees. Similar disparities between forecast and actual temperatures occurred on other days and in other areas, such as Philadelphia. As the days of January passed, temperatures became lower and lower, and National Weather Service projections began to specify this trend. Many severe weather bulletins were issued.

ECONOMIC COSTS

Although the closings of businesses and power interruptions of January 19, 1994, clearly had economic effects, DOE staff, and the various State regulatory agencies that have conducted investigations, have been unable to document or quantify these effects for the following reasons: Generic economic evaluations of power outages do not apply to the events of January 1994 because the cold weather itself may have depressed baseline economic activity and because few customers actually went without power for any extended period of time (in contrast to the New York City blackout of 1977).

Figure 1-2. Low-Temperature Forecasts for Washington National Airport and Philadelphia International Airport Versus Actual Low Temperatures, January 15-21, 1994

2

Electric Power

During the week of January 16, 1994, the weather and power supply situation was especially severe in that part of the Mid-Atlantic region served by members of the Pennsylvania-New Jersey-Maryland Interconnection Association (PJM), an 11-member power pool, and the Virginia Electric and Power Company (VEPCo [Virginia Power and North Carolina Power are operating subsidiaries of VEPCo]). Peak loads for many of the PJM utilities and VEPCo reached all-time record levels, and were also substantially higher than those of the previous 5 years. PJM experienced a new record peak load that surpassed the previous winter peak load of Christmas 1989. Figure 2-1 compares the pattern of PJM hour-by-hour demand for January 18-21, 1994, with the demand pattern on December 22, 1989. Both PJM and VEPCo instituted manual load shedding on Wednesday, January 19, to ensure the continuing reliability of the bulk power supply system.

Systems in other areas also experienced high loads caused by the cold weather. In the area of the East Central Area Reliability Coordination Agreement (ECAR), the Allegheny Power System (APS) issued public appeals to reduce electricity use, instituted voltage reductions, and curtailed interruptible loads. Ameri-

can Electric Power Company (AEP) operating subsidiaries in ECAR implemented voltage reductions. In the area of the Southeastern Electric Reliability Council (SERC), the Tennessee Valley Authority (TVA) system and Carolina Power and Light Company (CPL) implemented voltage reductions. In the Northeast Power Coordinating Council (NPCC), the New York Power Pool (NYPP) implemented voltage reduction to facilitate its sale of emergency power to PJM and recalculated the amount of power that could be delivered and still meet the established operations criteria.

Table 2-1 shows the utilities that set winter peak demand records on either January 17, 18, 19, or 20, 1994.

NORTH AMERICAN POWER SUPPLY STRUCTURE

The electric power supply structure for the contiguous United States is divided into nine regional reliability councils. Seven of these councils covering the Eastern United States operate in synchronism to form the Eastern Interconnection. The remaining two councils operate as independent entities for their respective geographic areas. In the Eastern Interconnection, the Hydro-Quebec

Figure 2-1. Comparison of the PJM Power Pool's Load on January 18-21, 1994, With December 22, 1989

Source: Provided in the written testimony of Phillip G. Harris, President, PJM Interconnection Association, to the Subcommittee on Energy and Power of the House Committee on Energy and Commerce, February 9, 1994.

system operates in an asynchronous mode from the rest of the Eastern Interconnection, thereby creating four major electric system operating groups, which cover most of North America. This arrangement is shown in Figure 2-2.

Each of these four networks has bulk electric transmission lines that connect the separate utilities to enable the transfer of limited amounts of electric power and energy from one part of the network to another. These interconnections have been constructed primarily for economic considerations such as shared ownership of large generating

stations. Through such arrangements these interconnections help enhance the reliability of the bulk power system. The largest of these networks by far is the Eastern Interconnection.

Within these four operating groups, electric energy supply operations are coordinated through about 140 operational control areas. These control areas are elements of the nine regional electric reliability councils shown in Figure 2-3. Inadequate generation in one area of an operating group affects other areas in the group that are sometimes very distant. However, this form of operation makes it possible for generation in a

Table 2-1. Peak Electricity Demand Records Set During the Week Ending January 22, 1994

System	Date of Peak Demand (January 1994)	Demand (Megawatts)
New England		
Boston Edison Co.	19	2,473
Connecticut Valley Electric Exchange	19	6,271
Eastern Utilities Associates	19	794
New England Electric System	19	4,121
Mid-Atlantic		
Atlantic City Electric Co.	19	1,510
Baltimore Gas & Electric Co.	19	6,038
Central Hudson Gas & Electric Corp.	20	840
Consolidated Edison Co. of NY	19	7,787
Delmarva Power & Light Co.	19	2,525
Long Island Lighting Co.	19	3,001
New York State Electric & Gas Corp.	19	2,618
Niagara-Mohawk Power Corp.	19	6,408
Pennsylvania Power & Light Co.	18	6,403
PECO Energy Co.	18	5,957
Potomac Electric Power Co.	18	5,010
Central Industrial		
Allegheny Power System, Inc.	18	7,153
American Electric Power Co. Inc.	19	19,236
Central Illinois Public Service Co.	18	1,989
Cincinnati Gas & Electric Co.	18	4,077
Cleveland Electric Illuminating Co.	18	3,233
Commonwealth Edison Co.	18	14,179
Consumers Power Co.	19	5,496
Dayton Power & Light Co.	18	2,747
Detroit Edison Co.	19	7,264
Illinois Power Co.	18	3,115
Indianapolis Power & Light Co.	18	2,543
Northern Indiana Public Service Co.	18	2,154
Ohio Edison Co. and sub.	18	5,098
Toledo Edison Co.	18	1,471
West Central		
Empire District Electric Co.	19	670
St. Joseph Light & Power Co.	17	276
Wisconsin Public Service Corp.	19	1,668
Southeast		
Carolina Power & Light Co.	19	10,129
Duke Power Co.	19	16,630
Kentucky Utilities Co.	19	3,092
South Carolina Electric & Gas Co.	19	3,444
Southern Company (P)	19	24,545
Tennessee Valley Authority	18	24,723
Virginia Electric and Power Co.	19	14,877
Total Number of Systems: 39		

Source: Based on a special telephone survey by the Statistics Department of the Edison Electric Institute, January 24, 1994

P= Preliminary

Figure 2-2. Major North American Electrical System Interconnections

Source: North American Electric Reliability Council, 1987. *1987 Reliability Assessment: The Future of Bulk Electric System Reliability in North America, 1987-1996*. Princeton, NJ. 1987.

(Figure provided in the written testimony of Phillip G. Harris, President, PJM Interconnection Association, to the Subcommittee on Energy and Power of the House Committee on Energy and Commerce, February 9, 1994)

remote area to be used to supply a load requirement in another area.

These regional reliability councils have established subareas, which are often the same as a control area. Members of the regional reliability councils themselves are connected by transmission lines of varying voltages and capacities. These interconnections are generally known as the bulk electric transmission system (sometimes called the power grid).

ENSURING THE RELIABILITY OF THE BULK POWER SYSTEM

Operating Parameters and Limits

The bulk electric transmission system operates according to laws of physics that cause the available electric energy to flow through the path of least impedance from the generator to

Figure 2-3. Regional Electric Reliability Councils in the Eastern Interconnection

ECAR: East Central Area Reliability Coordination Agreement

NPCC: Northeast Power Coordinating Council

MAAC: Mid-Atlantic Area Council

SERC: Southeastern Electric Reliability Council

MAIN: Mid-America Interconnected Network

SPP: Southwest Power Pool

MAPP: Mid-Continent Area Power Pool

Note: The HYDRO-QUEBEC area of NPCC operates asynchronous from its neighboring NPCC members.

the load. Despite this apparent simplicity, the many interconnection routes, with their varying operating voltages and capacities (sometimes due to line conductors and other times to terminal equipment ratings), and the basic nature of an alternating-current circuit make the analysis of the bulk power transmission system a very complex engineering study. Electric energy supply operations are dynamic and require highly trained

operators with detailed knowledge of their particular system and excellent communications with neighboring electric energy supply organizations.

Because each transmission system analytic study can represent only one instant in time, utility engineers attempt to ascertain the parameters (for example, maximum load, minimum load, and generator unit or transmission line outages) that will provide the maximum stress on the

system. From these analytic studies, operating parameters and limitations are established. One of these parameters is first contingency incremental transfer capability (FCITC), which is the amount of power, incremental above normal base power transfers, that can be transferred over the transmission network in a reliable manner. The FCITC is often referred to inaccurately as the transfer limit, as if it is an absolute number that is known to system operators and available to them through a sophisticated communications system. In reality, the FCITC should be considered as guidance only, because it is determined for only a single, very specific set of conditions.

The key elements in calculating the FCITC usually are capacity ratings, which, for most bulk electric transmission lines, are determined by conductor heating as current flows through them. Some of these ratings are limited by the rating of equipment at the terminal substations. In low ambient temperatures, conductor heating with increased load becomes only a minor concern, and loading usually can be increased to the equipment limits as controlled by the relevant protective relay systems. Protective relays that use data obtained from various local and remote monitoring devices are installed to ensure the safe operation of all components of an electric energy supply system. These factors allowed both NYPP and the Florida Coordinating Group (FCG) to increase temporarily their power delivery capability on January 19—NYPP, to PJM, and FCG, to Georgia, and thus the rest of the Eastern Interconnection.

NERC Operating Criteria and Guides

To keep supply and demand in balance and ensure the integrity of the interconnected system during the events of January 16–22, 1994, utilities followed the NERC Operating Manual's operating criteria and guides, which detail the control areas' obligations during energy emergencies. Actions taken during January 1994 in accordance with these guidelines included the following:

- Demand-side load management actions
- Interruptibility provisions of power supply contracts with large industrial and commercial customers
- Requests to large customers (including government agencies) for voluntary load reductions
- Public appeals for reduction of power use
- System voltage reductions
- Short-term (10- to 30-minute) rotating outages ("rolling black-outs") on selected distribution circuits

System operators operate their systems in accordance with the NERC Operating Manual, which requires that transmission facilities (including substation equipment) be operated within their nominal ratings, that voltage levels be maintained within specified tolerances, and that one control area does not operate in a manner that burdens the adjacent control area, except when prior arrangements have been coordinated.

Adequate Generation

One of the key elements in the reliability of electric energy supply is the availability of adequate generation. The capital cost of generating stations has forced State utility regulatory commissions to require that utilities only install the minimum generation required to serve the projected peak loads. In addition, the hourly operating costs of a generating unit are significant, and the inappropriate use of a system's electric generators can have a major impact on the finances of that utility. Thus, economic considerations are fundamental to the operations of the bulk electric energy supply system.

There are generating stations of various types, sizes, designs, fuels, and ages across the United States, all of which require regular maintenance, which is generally scheduled 2 to 3 months in advance with the other entities within the control area or power pool. Generating equipment experiences operating failures like all other mechanical equipment. These failures, commonly called forced outages, sometimes limit the output of the generating unit, while other times result in the loss of the entire unit.

Data regarding generator availability are routinely collected and compiled by the operating entity and forwarded to NERC for inclusion in the Generator Availability Data System (GADS). These availability data are utilized in electric system operating studies such that the proper actions can be taken to ensure that the highest degree of reliability is obtained.

System Frequency

Monitoring system frequency is a fundamental element in bulk electric power system operation. This frequency is directly related to maintaining a nominal balance between electric demand and the generating capacity available to supply it. When this balance is achieved, a nominal system frequency of 60 hertz (Hz; cycles per second) is achieved. As incremental load increases occur, the system tends to slow down while automatic generation control equipment opens valves, making additional generation available almost instantaneously to restore system frequency to 60 Hz. This frequency varies above and below 60 Hz throughout each day, with system operators implementing actions in accordance with NERC operating criteria to cause the sum of these frequency excursions to approximate zero each day. On January 19, the system frequency in the Eastern Interconnection began to drop below 60 Hz by 0.01 to 0.05 Hz in the early morning. When it dropped to 59.91 Hz at 7:00 A.M., with an apparent trend lower, PJM operators took many actions designed to restore the system to normalcy.

Figure 2-4 shows the nominal 60-cycle frequency of alternating current in the Eastern Interconnection on a typical winter day and compares it with the frequency on January 19, 1994. The system frequency on the 19th dropped to a value lower than normal for a short time. By implementing rotating manual load shedding (that is, rolling blackouts) in relatively small amounts, reducing voltage, and asking customers to reduce energy use, system operators

Figure 2-4. System Frequency on the Eastern Interconnection, January 19, 1994, Versus Typical Winter Day

managed to arrest the frequency decline well before the frequency approached the level at which automatic underfrequency relays would have initiated a load shedding of about 10 percent. Altogether, the 5-percent voltage reduction on January 19 lasted 13 hours and 43 minutes; and according to PJM, it reduced the peak demand by 600 MW, thereby reducing the amount of manual load shedding required.

Fuel Supply

Operating utilities usually have storage facilities at each generating site; these facilities generally can store approximately 40 to 60 days' worth of coal and heavy oil for the baseload coal- and oil-fired generators. These fuels are bought directly by the electric generator operator from a large fuel supply entity and usually are delivered by train or barge. Thus, there is little probability of a baseload fuel supply problem except during labor work stoppages or distribution anomalies. An often overlooked requirement of these heavy-oil and coal-fired baseload stations is the need to use light oil (the same as home heating oil) for ignition and flame stabilization. Because of its higher cost, light-oil use is normally minimized, and onsite storage capability is significantly less because light oil is available from many local sources. During cold and wet weather, however, the use of light oil for flame stabilization usually increases sharply because of the low fuel temperatures and possibly damp fuel.

Over the past 5 years, the use of natural gas to produce electric energy has increased sharply. Its cleanliness

and competitive price have made natural gas the fuel of choice for any electric utility that can receive and use it. To prevent natural gas shortages in times of peak demand, most natural gas used by electric utilities is acquired either through curtailable or interruptible contracts, thereby requiring the operating electric utility to have an alternate fuel supply. In most cases this alternate fuel is oil, with most of this being light oil. But because it decomposes over time, utilities maintain only minimum stocks of light oil at their generating station sites. Thus, when natural gas supply is curtailed, the light fuel oil requirements of the involved electric utilities increase significantly.

Light fuel oil is usually delivered by truck from local jobbers or the pipeline terminal over public roads, or by barge from nearby refineries when practical. Icy roads and frozen waterways therefore can cause fuel supply problems at some generating stations—a situation that actually occurred at many PJM locations during January 1994. Some generating stations used their entire on-hand fuel supply before the very low temperatures of January 18 and 19; as a result, this generating capacity was lost and unavailable to meet the peak loads on those days. The Pennsylvania National Guard was mobilized by the Governor of Pennsylvania to assist in the delivery of fuel to some electric generating stations.

Manual Load Shedding

Manual load shedding of customer load is the proper name for what is commonly called a "rotating blackout" by the media and even the

electric utility industry itself. The purpose of manual load shedding is to reduce the peak-load requirements in a specific electric bulk power supply control area (which may be a single utility, a group of utilities, or a large power pool such as PJM). It is used only when the total power requirements in a specific control area exceed or are projected to exceed the actual total available power supply. This total power supply is the sum of the operating electric generation plus the power available through the transmission interconnections with other control areas.

Manual load shedding is the last and most drastic step in the management of the bulk electric energy supply system, and is employed only after all available demand-side management (DSM) systems (including customer appeals and the direct control of selected customer loads) and reductions in system voltages (of 3 to 7 percent) have been implemented. Manual load shedding, in contrast to automatic underfrequency load shedding, is a system-operator-controlled operation that is usually implemented only on radial distribution (2.4/4.14 kV to 19.9/34.5 kV) circuits by distribution system operators via System Control and Data Acquisition (SCADA) systems.

The operating procedures of all electrical control areas contain detailed procedures for manual load shedding. Usually, these procedures specify the process to be employed to disconnect the load and the amount of the load expected to be dropped. Some electric utility SCADA systems are sophisticated enough to be programmed to take disconnection actions until a certain amount of load

is disconnected. Manual load shedding becomes a rotating blackout shortly after it is initiated, because utilities attempt to minimize customer inconvenience by returning a distribution feeder circuit to service within a reasonable time after its interruption, and after another feeder is interrupted to maintain approximately the same amount of load interrupted.

In the past, most manual load shedding operations have occurred during the summer peak-load period, and operating procedures of some utilities allowed the disruption period to extend for about an hour or a little longer. The use of manual load shedding in winter, however, poses a number of potential serious public health and safety problems (mostly linked to the operation of home heating systems); therefore, the interruption periods are much shorter. During the power shortages of January 19, 1994, the data from the involved utilities indicate that the interruptions ranged from 10 to 25 minutes, with most in the 10- to 15-minute range. Sometimes, when electrical load is interrupted on a distribution feeder at a substation through SCADA control and then restored remotely, a phenomenon known as "cold load pickup" causes other problems, such as line sectionalizer lockouts or blown line fuses. When this occurs, the length of the customer outage is significantly extended because an electrical service person must come to the location, ascertain the problem, and take the appropriate corrective action.

During the January 19 manual load shedding by the Baltimore Gas and Electric Company, a "cold load pickup" problem occurred in the

Columbia, Maryland, area, and the subsequent customer outage lasted several hours.

Keeping the outage period short is a key element in reducing the number of "cold load pickup" problems. Most electric utilities involved in the January 1994 crisis have prepared and tested media relation programs that explain what is happening during a manual load shedding, and they provided specific procedures for customers to follow when their load was disrupted for more than the prescribed time. Without such procedures the public health and safety impacts of manual load shedding could be exacerbated.

To mitigate the potential public health and safety impacts of manual load shedding operations, utilities—with the approval of their State regulatory agency—exempt certain circuits that supply hospitals, public safety facilities, or similar loads. Identifying these loads *before* a manual load shedding becomes necessary is a key preparedness activity. The exemption of feeder circuits must be minimized or there could be very little load left to be shed in an emergency. For this reason, the appropriate State regulatory agencies often are directly involved in approving circuits for exemption. During the manual load shedding of January 19, some hospitals, natural gas compressor stations, and other critical loads were disrupted. Adjustments were made by the involved utilities to remove these critical circuits from the next rotation once the problems with the manual load shedding were accurately defined.

Because of technical reasons, areas in an electric utility service area that

are supplied by networks are usually exempt from manual load shedding operations. These networks are used by electric utilities that serve large metropolitan areas to provide a higher degree of service reliability. These service arrangements are justified by the fact that the load density in these areas is usually very high, and there is the possibility of severe public health and safety problems during a manual load shedding. Networks are supplied by multiple underground cables that may originate at different bulk transmission substations. Restoring urban underground electrical cable system networks presents many special technical challenges—all feeders could have to be connected at the same time, or there could be an overload on the remaining feeders, which could cause significantly more severe equipment damage. The Public Service Commission of the District of Columbia examined Pepco's actions during January 1994 and concluded that exempting networks from manual load shedding operations was an appropriate and proper action.

CHRONOLOGY OF THE MAJOR EVENTS OF JANUARY 1994

The actions taken by energy supply entities during January 1994, along with government actions, are described in the following paragraphs. A detailed chronology of major events during the crisis period, beginning with PJM's Cold Weather Message on January 13, is provided in Appendix C. In general, the actions taken by

electric utilities were those they had implemented in the past to deal with similar power shortages during peak-load periods. PJM, for instance, has dealt with abnormal demand/supply events a number of times in the past (Appendix E) and has developed effective response procedures.

PJM

Role of PJM

The Pennsylvania-New Jersey-Maryland Interconnection Association is composed of 11 electric energy supply entities in the Mid-Atlantic region. From its control center near Valley Forge, Pennsylvania, PJM controls the electric system operations in the same area as MAAC, an electric reliability council composed of major investor-owned utilities. PJM is responsible for coordinating the dispatch of the power generators owned by its members and for operating the bulk power transmission system in the region. It is a single control area and the largest power pool in the country.

PJM is a highly integrated, formal, tight power pool (that is, it operates as a single system wherein there is constant "free flowing" energy among its member companies). About 60 percent of its installed capacity is under automatic control. PJM also ensures that its members follow the established NERC operating criteria and guides in the NERC Operating Manual.

There is a formal agreement among the PJM members that has been approved by the Federal Energy Regulatory Commission. The agreement principally covers the economic

aspects of PJM operations, including provisions for both electric energy exchange among members and with outside parties. In addition to this agreement, PJM has developed a set of operating procedures, including actions in power supply emergencies, that apply to all of its members. The load reductions of specific PJM procedures are listed in Table 2-2.

PJM strives to enhance the adequacy and reliability of the bulk electric power supply of its members and to achieve economic efficiencies—and therefore savings—for its member utilities. PJM has an extensive data and voice communications network with and among its members. This communications network uses dedicated commercial telephone system circuits along with microwave and fiber-optic systems owned and operated by member utilities. Economic bulk power system operations data and bulk transmission system status reports are routinely shared among the members through these communications networks. However, the PJM agreement does not cover the operations of the lower voltage power distribution and secondary systems used to deliver electric power to its customers, nor does PJM become involved in the acquisition of fuel or the management of fuels at individually or multiparty-owned-and-operated generating stations.

PJM Actions

Section 2 of the PJM operating guidelines provides for and describes the required actions for issuing alerts and warnings to member organizations when appropriate. In accordance with these guidelines, on Friday, January

**Table 2-2. PJM Emergency Load-Reduction Procedures
(in order of implementation)**

Load-Reduction Procedure	Estimated Peak Load Reduction (megawatts)
1. Curtailment of nonessential power company station light and power	75
2. Curtailment of controllable interruptible/curtailable loads	1,700 (summer) 1,000 (winter) dependent on customer response
3. Five-percent voltage reduction	750
4. Curtailment of nonessential load in power company buildings	25
5. Voluntary customer load curtailment as required, up to maximum shown on a procedural basis	525 (summer) 400 (winter)
6. Radio and television load curtailment appeal	Dependent on public response
7. Manual load dumping ("rolling blackouts")	As required

14, PJM issued a Cold Weather Alert as specified in section 4.4. The alert lasted from 5:00 A.M. to 9:00 P.M. on Sunday, January 16. The PJM guidelines state that such alerts are to be issued in advance of a scheduled load period so member organizations have sufficient time to prepare for the anticipated conditions.

Under a Cold Weather Alert, dispatchers are to assume a higher rate of unavailability of power purchases from the west, thereby making PJM more dependent on its own generating resources. In addition, PJM dispatchers are required to furnish an estimated running rate for the "highest priced" combustion turbine, presumably so PJM utilities can prepare for additional operation of these combustion turbines. In addition to these actions, the Cold Weather Alert requires member

utilities to assign operating staff and maintenance capabilities to ensure the availability of any needed combustion turbines and to ensure that the appropriate cold-weather additive is added to the fuel supply of units using No. 2 fuel oil.

The PJM Cold Weather Alert triggered a number of actions by its member utilities. DOE is not in a position to evaluate the appropriateness or consistency of the actions taken. However, it is clear that the principal cause for the mandatory PJM load shedding on Wednesday, January 19, 1994, was the unavailability of the installed generation in the PJM area.

Fuel shortages and fuel-handling difficulties due to the extremely low temperatures have been identified as major factors in this unavailability. Because of a much-higher-than-

normal or -expected usage of generators (especially some combustion turbines using light fuel oil), the fuel supply at several PJM generating stations had become very limited or exhausted by the evening of Sunday, January 16, 1994. Icy and snow-covered roads, along with the frozen Delaware and Schuylkill Rivers, prevented or limited fuel resupply activities.

Monday, January 17, was a Federal holiday, and Federal and most State government agencies and many industrial concerns in the PJM area were closed. Historically, both the peak load and energy supply requirements on a Federal holiday are less than on a normal Monday in January, so PJM dispatchers operated the PJM network on the 17th without implementing any special or emergency procedures. However, both the peak load and energy supply needs were much higher than had been expected. An additional complicating factor on this day was snowfall in many areas throughout the PJM area; for example, Harrisburg, Pennsylvania, received more than 17 inches.

On the morning of Tuesday, January 18, PJM achieved a high peak load that required a high level of power purchases from adjoining utility systems. This peak load identified a potential problem for the evening peak that was expected around 6:00 P.M. Several executive-level telephone conference calls among the member organizations were conducted, and the PJM dispatchers made arrangements to purchase all available power from APS to the west and NYPP to the north. Between 6:00 and 7:00 P.M., PJM established a record winter peak load

of 41,350 MW, exceeding its previous winter peak load of 38,100 MW in December 1989. To supply this record peak load, PJM issued several alerts and warnings, including the following: Maximum Scheduled Generation at 3:40 P.M., Maximum Emergency Generation at 4:30 P.M., Voltage Reduction Warning at 4:48 P.M., and Manual Load Dump Warning at 5:08 P.M. Between 7:00 and 9:00 P.M., PJM's spinning reserve was at zero as it struggled to supply the load.

After 9:00 P.M. the load requirement began to decrease, and PJM's spinning reserve increased to nearly 2,100 MW by midnight. After the record peak load on Tuesday evening, PJM updated its power supply assessment for Wednesday morning, January 19, and determined that it would be able to meet load requirements. However, temperatures on the night of January 18 and during the early morning hours of January 19 plummeted to lower-than-projected levels, causing system peak load and energy requirements for this period to be much higher than had been projected. Following the loss of a large coal-fired generating unit at the Conemaugh Station in the early morning, PJM made another assessment of the expected situation during the Wednesday morning peak load and determined that it probably could obtain some additional power from NYPP. A technical study was required to increase the power transfer limits. However, PJM did issue a series of alert and warning orders to its member utilities. Among these orders were the following: Primary Reserve Warning at 3:55 A.M., System-Wide Voltage Reduction Warning at 5:06 A.M., the Implementation Order at 6:45

A.M., and radio and TV appeals urging customers to minimize their electric use. By 7:00 A.M., the PJM spinning reserve had dropped to zero.

As the conditions changed during the early morning of January 19, PJM dispatchers were involved in many telephone calls with Eastern Interconnection management and the executives of the member utilities. There were several conference calls involving the PJM Operating and Management Committees. System frequency in the PJM area and throughout the Eastern Interconnection had fallen below the nominal 60 Hz by a few hundredths of a cycle in the early morning hours, but there were some limited periods of frequency recovery to nearly 60.0 Hz (Figure 2-4). Electric utility system operators in many areas of the Eastern Interconnection communicated extensively with neighboring and nearby electric utility systems to ensure that any available generation was on line, and/or took action to buy or sell all available power.

Despite the extensive communication among PJM, VEPCo, APS, AEP, and many other utilities in the eastern area of the Eastern Interconnection, there were, after the fact, reports from the MAIN (Illinois, Wisconsin, Iowa, and Missouri) and SPP (Arkansas, Missouri, Oklahoma, Mississippi, Kansas, eastern Texas, and Louisiana) regions of the interconnection at a NERC meeting in April 1994 indicating that, for the most part, they were unaware of the developing critical power supply situation in the eastern areas of the interconnection until it was mostly over.

Although power flows from the west to the east across the ECAR region were very heavy and near load

limits, no control area has provided any documentation of any overload on the interconnection, or other major uncorrectable problem, that would have been caused by the flow of some additional amounts of power to PJM or VEPCo—power that could have partially mitigated the developing crisis. FERC's evaluation of the bulk power transmission system failed to identify any contractual constraints that may have prevented the flow of additional power to the PJM or VEPCo areas.

Shortly after 6:00 A.M. on January 19, two 500-kV transmission lines—one in the PJM area, one in the APS area—tripped. The loss of these lines and the increasing loads exacerbated the overall bulk power supply situation, and system frequency began to drop (Figure 2-4). Levels I and II of a Reliability Coordination Plan (RCP) involving PJM, VEPCo, and APS had been previously implemented to alleviate some APS system voltage and transmission line-loading problems. The RCP implementation placed special coordination requirements on VEPCo, APS, and PJM for additional power transfers and established the need to possibly require generation adjustments, a freeze on power transfers, or even a reduction in power transfers. Despite all these actions, system frequency continued to drop, with a sharp drop between 6:30 and 7:00 A.M. when it reached a low of 59.91 Hz. Because the PJM peak-load requirements had exceeded projected levels and were more than the available generating capacity, PJM—as required by the NERC operating procedures stating that no control area is to “lean” on the interconnection to the detriment of

the other operating systems—was required to take action. At 7:05 A.M., PJM made the decision to manually shed 500 MW of load. Following this manual load shedding, the system frequency began to recover, and there appeared to be some lessening of load requirements, apparently due to consumer responses to the radio and TV appeals. With this apparent load stabilization and the arrest of the frequency decline, PJM at 7:41 A.M. directed its members to restore all manually shed load.

With the rotating "blackouts," the seriousness of the situation became a constant media subject, and consumers appeared to cooperate extensively by minimizing their electricity requirements. The PJM member utilities initiated many actions to inform the public of the situation and to request their assistance in reducing the PJM peak-load requirement. All available demand-side-management schemes were activated, and direct contacts with large commercial and industrial customers were made, in accordance with preestablished procedures, to request them to minimize their electrical load requirements.

The Department of Energy's Headquarters in Washington was contacted by APS for assistance in approving the reduction of the load requirements of the nuclear fuel enrichment facility in Portsmouth, Ohio. This DOE load was reduced by 365 MW by 10:00 P.M. that day.

By 8:00 A.M. conditions on the PJM system had improved significantly, and an emergency sale of 500 MW was made to VEPCo to help it meet its growing loads. However, the power supply conditions in the PJM area began to deteriorate again, and the

sale was curtailed at 8:15 A.M. The loss of this power exacerbated the conditions on the VEPCo system, which initiated manual load shedding shortly thereafter. The New York Power Pool instituted a 5-percent systemwide voltage reduction at 8:22 A.M. to make additional increments of power available for delivery to PJM.

As the morning passed, PJM load requirements continued to increase, causing the system frequency to begin to decline again. With the power flow on the transmission connections from New York approaching its FCITC limit, PJM decided to reinstitute manual load shedding in the PJM area at 9:22 A.M., ordering its member entities to shed 500 MW at that time. An additional 500 MW was shed at 10:10 A.M. and another 500 MW at 11:44 A.M., for a total of 1,500 MW of customer load rotated in and out of service. The average load disruption lasted from 10 to 30 minutes. PJM directed its members to begin the restoration of all manually curtailed loads at 12:54 P.M., and this action was completed by 1:07 P.M.

Around 9:00 A.M. on Wednesday, January 19, NYPP, at the request of PJM, initiated a reevaluation of the FCITC between these two adjacent regions. By 11:12 A.M., the necessary technical studies had been completed, and the limit was increased from 3,000 MW to 3,600 MW, thereby enhancing NYPP's capability to provide assistance to PJM. In a similar situation, the Florida Coordinating Group of the Southeastern Electric Reliability Council and the Georgia Power Company reevaluated their limits on power flows from Florida to Georgia via the available transmission interconnections; the previously

established limit of 1,300 MW was increased to 3,000 MW (in increments of 500 megawatts) as security studies indicated.

Virginia Electric and Power Company Actions

Virginia Power and North Carolina Power are operating organizations of the Virginia Electric and Power Company (VEPCo). VEPCo's executive headquarters and systems operations office are both in Richmond. Virginia Power supplies electric power to most of central and eastern Virginia and a large portion of northern Virginia. North Carolina Power supplies consumers in northeastern North Carolina. VEPCo is a separate control area like PJM and as such has operating procedures in accordance with the NERC Operating Manual. VEPCo is a member of the Virginia-Carolinas (VACAR) subregion of SERC.

VEPCo experienced a new system peak load on Saturday, January 15, and saw this peak load exceeded again on Tuesday evening, January 18. Many other electric utilities experienced similar conditions. After implementing its DSM system (involving mostly hot-water heaters and direct contacts with their large commercial and industrial customers), a Tuesday evening peak load of 13,422 MW was established at 7:00 P.M., only to be surpassed by a 9:00 P.M. peak load of 13,478 MW. The usual time for evening peak loads in the winter is 7:00 P.M.; therefore, the 9:00 peak load was very unusual. It is likely that the reconnection of the water heaters for the 7:00 P.M. peak

and low temperatures combined to create this unusual peak-load time. The system load declined to 12,427 MW at 1:00 A.M. on Wednesday, January 19, and then began to increase again. Another oddity occurred when VEPCo experienced a new winter peak load of 14,877 MW at 8:00 A.M. despite the use of its DSM system and radio and TV appeals asking customers to minimize their electric use. VEPCo estimates that without these actions their peak load would have been around 15,600 MW.

On Tuesday evening, as the new peak loads were being established, VEPCo utilized its short-term daily load projection computer model to plan for the next day's operations. This model indicated that its peak load should have been about 13,800 MW and that a total of 15,337 MW of generation capacity and purchased power would be available to serve this load. These modeling results assumed the availability of 3,125 MW of power from nonutility generators (NUGs) that had contracts with VEPCo. However, nearly 1,100 MW of this NUG capacity was not available Wednesday morning. In addition, some power purchases from other systems were not available because of the low temperatures over much of the Eastern Interconnection and some forced generating outages on other systems.

Another factor in VEPCo's supply shortage and manual load shedding on January 19 was the limits on the output of the Bath County Pumped Storage Plant near Staunton, Virginia, a generating station VEPCo jointly owns with APS. VEPCo has 1,260 MW of generation at Bath County. Because it is a pumped storage facility, the

amount of generation available depends on the water available in the upper reservoir, which must be pumped to that location using the generators as pumps during periods of light load.

The VEPCo system operator had made heavy usage of the Bath County generators during the peak loads of Tuesday evening, which reduced the water available in the upper reservoir to operate the generators. Because in normal situations, and even according to the available computer models, the load level significantly decreases during the late night and early morning hours, it was anticipated that the upper reservoir could be refilled by the time of the peak load on Wednesday morning. However, as previously stated, load levels remained high throughout the night, and there was no power available from VEPCo generating stations or other nearby utilities to refill the upper reservoir before the Wednesday morning peak.

According to VEPCo, the most significant element of its power supply shortages on Wednesday, January 19, was the inaccuracy of its short-term peak-load forecasting computer model in the system operator's office. This system, based on the expected low temperatures, had projected a peak load for Wednesday morning of 13,800 MW, which turned out to be 1,800 MW lower than the estimated potential load of 15,600 MW. VEPCo officials indicated that had the short-term load model provided a more realistic number for the projected peak loads, they would have taken a number of additional actions, such as public appeals, during the night and early the next

morning that may have prevented the need for manual load shedding.

At 3:10 A.M. on Wednesday, January 19, the on-duty system operator notified VEPCo management that the early morning loads were much higher than projected and that there were some possible major problems on the horizon. At 5:32 A.M., a decision to institute public appeals on radio and TV was made and the appropriate actions initiated. Because of the timing of these appeals, very little effect was realized immediately. At 5:43 A.M., VEPCo activated its Plan IIB and began to directly contact its industrial customers, requesting them to reduce their current and expected load requirements for the morning of January 19. With the system power supply condition very tight, VEPCo implemented a systemwide voltage reduction at 6:17 A.M. and continued efforts to purchase all available power. A 200-MW load diversity contract delivery to APS was cancelled to make more capacity available for VEPCo's own loads.

When PJM manually shed load at 7:05 A.M., the situation in the Eastern Interconnection was ameliorated to some degree. The VEPCo situation improved substantially beginning at 8:00 A.M., when PJM initiated the sale of 500 MW under the provision of an emergency purchase tariff. Unfortunately, PJM notified VEPCo at 8:15 A.M. that this sale would be cancelled in 5 minutes (at 8:20 A.M.) because of conditions on the PJM system. VEPCo made an immediate decision to institute manual load shedding of 400 MW, which began at 8:22 A.M. At 8:45 A.M. another block of 400 MW was placed in the manual load shedding program, for a total of 800 MW of

load manually shed on a series of rotating interruptions, each of which lasted approximately 15 minutes.

As system conditions improved because of additional power available for purchase and the lowering of consumer load requirements in response to public appeals, the amount of manual load shedding was gradually reduced in four 200-MW blocks beginning at 11:00 A.M. The second 200-MW block was restored at 11:30 A.M., the third at noon, and the last at 12:15 P.M.

Allegheny Power System Actions

The Allegheny Power System is a holding company for the West Penn Power Company, which serves a large area of western Pennsylvania; the Monongahela Power Company, which serves a portion of West Virginia; and the Potomac Edison Company, which serves portions of Maryland and Virginia. APS, a member of the East Central Area Reliability Coordination Agreement, is a single control area and operates a system control center in Greensburg, Pennsylvania, that covers geographic regions in Pennsylvania, Maryland, Virginia, and West Virginia. Its bulk transmission system connects to PJM to the east, to Virginia Power to the south and east, and to AEP and other ECAR members to the west. Its location is critical to most electric power flows from the west to PJM or VEPCo.

APS experienced many of the same conditions as PJM and VEPCo over the weekend and on the Federal holiday on January 17. By the afternoon of Tuesday, January 18, the APS system was facing a peak-load

projection that would have been difficult to supply. Public radio and TV appeals and direct commercial and industrial customer contacts were made to lessen the expected peak-load requirements. Despite these actions and a 5-percent systemwide voltage reduction initiated at 5:40 P.M., APS experienced a system peak load of 7,153 MW on Tuesday evening—7 percent higher than the previous winter. The systemwide voltage reduction continued until 11:27 A.M. on Wednesday, January 20.

The APS system lost a 555-MW generator on Saturday, January 15, and then another 550-MW generating unit on Tuesday morning, January 18, because of forced outages. Both units experienced boiler tube ruptures, which require several days to repair. With the forced outage of these two large generating units, APS had to import additional power from the west to ensure adequate power to supply its customers. These increased imports by APS reduced the power that could flow through the APS system to meet the emergency requirements of either PJM or VEPCo, because these high power flows to APS loaded the APS transmission system to near its capacity. Levels I and II of the RCP were implemented in response to these indicators, and to allow the maximum power to be made available to every system needing it.

Other Electric Utility System Actions

Most electric utilities in the Eastern Interconnection took actions involving only their system to assist their

neighboring systems. Some of these actions were as follows:

- Indianapolis Power and Light: Appeals to industrial and large commercial customers; public appeals
- Duquesne Light Company: Public appeals; appeals to large commercial and industrial customers
- Carolina Power and Light: Water Heater Control Program; 5 percent system voltage reduction
- Tennessee Valley Authority: Curtailment of Economy Energy sales; public appeals; distribution load reduction programs
- American Electric Power: Interruptible industrial customer loads; appeals to large commercial and industrial customers
- Duke Power Company: Water heater control program; standby generator program
- East Kentucky Cooperative: Public appeals; appeals to large commercial and industrial customers
- Cincinnati Gas and Electric: Appeals to large commercial and industrial customers
- Ohio Edison: Interruptible customers; appeals to large commercial and industrial customers
- New York Power Pool: 5 percent systemwide voltage reduction

The above list was taken from the NERC report on the events of January 1994 and is included as a demonstration of the cooperation and mutual support in the electric energy supply industry.

Communications and Coordination

Throughout the Northeastern United States and Eastern Canada, the operations systems of the major electric energy supply control areas communicate through a wide-area computer network known as ORNS. This name is derived from the group of northeastern electric utility systems operations representatives that established it many years ago as a teletype network. ORNS currently has terminals at Ontario Hydro in Toronto; Canada American Electric Power in Columbus; the Ohio Michigan Electric Coordination Center in Ann Arbor; the Michigan Cleveland Electric Illuminating Company in Cleveland, Ohio; Ohio Edison in Canton, Ohio; the Allegheny Power System in Greensburg, Pennsylvania; the PJM Interconnection in Valley Forge, Pennsylvania; VEPCo in Richmond, Virginia; the New York Power Pool in Schenectady, New York; and the New England Power Exchange in Holyoke, Massachusetts.

ORNS has protocols for information sharing and is used extensively during emergencies to share information on the condition of the electric power supply. Despite ORNS's extensive use for electric utility bulk power supply operations, it is not described in the NERC Operating Manual.

NERC sponsors an Eastern Interconnection Interregional Emergency Telephone Network that uses dedicated telephone circuits with two-

digit dial codes. This network is commonly known as the NERC Hotline. According to the NERC Operating Manual, "this telephone network is intended for emergency or near-emergency situations of a nature which involve or affect the Eastern Interconnection and when time is a major factor in recognition." There is a single terminal within each of the regional reliability councils in the Eastern Interconnection. Each terminal operator is responsible for the further dissemination of Hotline information in its council area per established procedures. The only identified use of this communications system on January 19, 1994, was a request by the Carolina Power and Light Company in Raleigh, North Carolina, at 6:15 A.M. for emergency assistance.

Within the next 2 years, a group of electric utilities, mostly in the Northeast and mostly the same as those on ORNS, will have developed and begun to install equipment for another wide-area data exchange network—the Informational Data Exchange Committee network, or IDEC system. IDEC now extends beyond the ORNS members to include Duke Power Company in Charlotte, North Carolina. IDEC is intended to process and share selected key bulk power system operating data among the involved systems. Much of this information will be provided to IDEC via telemetry points at critical points on the involved utility systems.

Installation of IDEC was incomplete in January 1994.

CANADIAN ASSISTANCE

Canadian utility members of the Eastern Interconnection provided substantial assistance to U.S. systems during the emergency. Even though low temperatures in Canada resulted in high domestic demands for electric power, sufficient additional resources were available to provide large amounts of needed capacity and energy to utilities in New York, Michigan, and Minnesota. On January 18, for instance, the Hydro-Quebec system met a new all-time domestic peak demand of 30,345 MW while fulfilling supply contracts with other Canadian systems; and it also provided a maximum of 3,500 MW to U.S. utilities. On January 19, Ontario Hydro sold a combined total of 4,119 MW to utilities in New York and Michigan; the previous record was 3,208 MW sold on December 21, 1979. On January 20, the Manitoba Hydro-Electric Board furnished 912 MW to U.S. utilities in the north-central part of the Eastern Interconnection. This inflow of power from Canada also allowed the northernmost U.S. systems to contribute power to utilities farther south.⁴

STATE AND LOCAL ACTIONS

State and local governments took a variety of actions to deal with the energy supply problems of January 1994, including issuance of emergency waivers of transportation and environmental regulations; situation monitoring; clearing of ice from

roads; arrangement of deliveries of natural gas, fuel oil, propane, and kerosene; and expanded public health and safety services. In New Jersey, Pennsylvania, Virginia, and the District of Columbia, Declarations of Energy Emergency were issued. These declarations varied widely in their provisions, from temporarily restricting and closing business establishments to shutting down government operations.

Each State's energy emergency response activities are organized differently, but typically a State energy office and the State agency that regulates utilities will be involved with the State's separate emergency management office. County offices are also an important part of the emergency response structure in many States.

Pennsylvania provides an illustration of State government activities during January 1994.⁵ The Pennsylvania State emergency management office was first notified of utility problems on Wednesday, January 18, several days after utilities were aware of potential problems. The State public utility commission alerted the energy office that a utility had lost several large units and might have trouble meeting demand. Because of voltage reductions, interruptible customer cutoffs, and rolling blackouts, the State government lost phone service for a short period, a refinery in Philadelphia had to shut down, and fuel suppliers had difficulty pumping critically needed product into their trucks. At the request of PJM, the State government attempted to reduce statewide load. Governor Casey expanded the State's Declaration of Emergency to include the entire State

and requested voluntary commercial and industrial closings.

Frozen rivers in Pennsylvania prevented delivery of coal and fuel oil by barge. The Philadelphia Electric Company requested and received assistance from the U.S. Coast Guard, which brought icebreakers in from the Atlantic Ocean to free fuel barges. The Pennsylvania National Guard worked 24 hours a day assisting in deliveries of fuel oil to two Philadelphia Electric Company oil-fired turbine facilities and a Philadelphia cogenerator, and also coordinated emergency shelter activities.

FEDERAL GOVERNMENT ACTIONS

The Federal Government took a number of actions to deal with the cold-weather episode, including the following:

- The Department of Energy reduced the electrical demand of its facility at Portsmouth, Ohio, by 365 MW in compliance with a request by the Allegheny Power System to reduce load
- The U.S. Coast Guard provided icebreakers to assist in moving fuel barges on frozen rivers
- Federal buildings in Washington, D.C., and most areas of Pennsylvania were closed, except for the most essential activities, on January 20 to reduce demand on the Pepco system
- The U.S. Department of Transportation declared a regional emergency to allow interstate carriers to

function in the region without all standard permits

Notes

¹These responses are documented in testimony before the Subcommittee on Energy and Power of the House Committee on Energy and Commerce by Phillip G. Harris, President of PJM, February 9, 1994, by John M. Derrick, Jr., President and Chief Operating Officer, Pepco, March 17, 1994; and by Larry W. Ellis, Senior Vice President, Virginia Power, March 17, 1994, and in testimony before the Washington, D.C., Public Service Commission by Paul Dragoumis of Pepco, (Volume II of IV), April 4, 1994.

²Waivers reported by Pepco in Volume II of its testimony before the D.C. Public Service Commission included the following:

- Hours of service exemption for Commercial Motor Vehicle Drivers (CMV) from Maryland, D.C., and Virginia to allow drivers to "book" extra hours and continue to operate. (This exemption also applied to Pepco's electric system repair crews, enabling them to work longer hours in response to weather-related customer outages.)
- Waiver of Maryland oil vehicle operator certificates by the Maryland Department of

the Environment, to allow out-of-state vehicles to immediately begin transporting fuel oil to Maryland facilities.

- A regional emergency declared by the U.S. Department of Transportation, to allow interstate carriers to function in the region without all standard permits.
- Lifting of weight restrictions on fuel vehicles by the Virginia Department of Transportation, allowing carriers to "bypass" the scales and expedite fuel oil deliveries.

³Holiday loads are generally typical of weekend loads, when many commercial and government establishments are closed.

⁴Letter dated May 4, 1994, from the Canadian Embassy in Washington, D.C., to Dennis K. Taillie, Director, Office of Emergency Planning, U.S. Department of Energy, and subsequent information furnished by Hydro-Quebec.

⁵Pennsylvania State events are documented in testimony before the House Subcommittee on Energy and Power by Brian T. Castelli, Executive Director, Pennsylvania Energy Office, February 9, 1994.

3

Natural Gas

Natural gas demand during the week of January 16, 1994, approached record levels. The 2,538 billion cubic feet (bcf) of gas consumed in January 1994 was the highest level since January 1973. Had the West not been warmer than normal, a national all-time consumption record might have been established. Further, the gas supply in January 1994 was delivered to more users, and over a significantly greater area, than in January 1973 (this is because large volumes of sales in 1973 went directly to powerplants in the Southwest and to other industrial boiler-fuel users, which also reduced the burden on distribution systems as compared with January 1994).

On average, natural gas use in consuming regions in January is about twice that of August; during the winter months, any significant departure from normal temperatures will directly and immediately increase demand for natural gas. January 1994 is an excellent example of a monthly peak that was created by extremes in a few daily peaks that occurred during the week of January 16–22. (Monthly peaks are calculated by summing daily peaks; in a “normal” winter month, wide variations in daily supply and demand are common.)

In a survey of 21 pipeline companies that supplied the Eastern United States during the week of January 16–22, the Interstate Natural Gas Association of America (INGAA) found that the throughput level for the week represented an all-time high and was larger than the sum of the historic peaks from any year for the 21 pipelines surveyed. INGAA reported that 12 pipelines equalled or exceeded all-time weekly throughput levels. On average, the throughput level for the 12 pipelines was 9 percent higher than previous all-time highs. Four pipelines also met or set all-time highs for the week for storage withdrawals.

New all-time daily highs were also set: The INGAA survey reported new records for send-out, market deliveries, scheduled transportation, and throughput, and eight pipelines set all-time records for individual days. On average, these records were 8 percent higher than previous records.

Peak-day demand can significantly exceed the supply of gas from current production and imports. Deliverability, particularly during demand surges, depends heavily on the availability of natural gas in storage. Energy Information Administration (EIA) data show that 723.8 bcf of gas

was withdrawn from storage in January 1994 for the entire United States. This is a monthly record and a 30-percent increase over January 1993.

The American Gas Association (AGA) surveyed several of its member local distribution companies (LDCs) in the general area affected by the cold to determine their send-out volumes during the January 18-20 period. All seven of the LDCs surveyed equalled or exceeded their design day at least twice, and five LDCs equalled or exceeded their design day for the 3-day survey period (Table 3-1). Although LDCs do not always use the same methodology in calculating their design day, a design day generally refers to a 1-day send-out that would occur no more than once in 25 years.

Fortunately, the cold weather of January 1994 did not significantly affect natural gas production in the major producing regions. Although some downstream storage fields in Ohio, West Virginia, Pennsylvania, and New York experienced some storage withdrawal problems due to frozen valves, these were fixed

quickly, and their overall impact on production and service was limited.

GENERAL NATURAL GAS INDUSTRY OPERATIONS DURING PEAK DEMAND PERIODS

Natural gas is moved from major producing regions, such as the Gulf of Mexico and East Texas, to major consuming regions through large interstate pipelines. Pipelines must carefully coordinate receipts from producers and withdrawals from storage to ensure a balance between these inputs and the gas taken from the system by consumers. This helps maintain adequate pressures to maximize pipeline throughput during peak-demand periods. Figure 3-1 shows the basic industry structure for the flow of gas from source to consumer during peak periods.

Underground storage facilities are a key element in ensuring that pipelines are able to meet peak-day

Table 3-1. Peak Day Send-Outs (kilodekatherms)

Company	Monthly Average, January 1993	Design Day	Average Daily Send-Outs, January 1994		
			18	19	20
Washington Gas	750	1,245	1,245	1,288	1,131
Union Gas Limited	2,700	4,174	4,405	4,562	4,323
Nat. Fuel Gas Dist. Corp.	772	1,219	1,386	1,409	1,276
Nat. Fuel Gas Supply Corp.	1,100	2,008	2,023	2,126	2,014
Elizabethtown Gas Company	243	354	324	357	347
LIGI Utilities, Inc.	334	439	466	478	447
East Ohio Gas Company	1,361	2,391	2,586	2,548	2,224

Figure 3-1. Natural Gas Flows During Peak Periods

deliverability. During offpeak periods, underground storage facilities in Ohio, West Virginia, Pennsylvania, and New York are filled to capacity. In the winter months when demand exceeds overall pipeline capacity, natural gas is withdrawn from these facilities to meet expected cold-weather-related demand surges. LDCs provide additional storage at "peak shaving" facilities located close to the point of consumption; such facilities include liquefied natural gas (LNG), propane-air, and low-pressure natural gas stored in aboveground tanks. Peak shaving, used to meet hourly swings in demand and to provide short-duration peak service, is usually limited to a few days each winter because of the high cost of maintaining such supplies.

Line-packing, in which pipelines are temporarily overloaded (with some loss in economics), is another operational technique to meet a

predicted surge in demand. By varying pressure in the line, natural gas is temporarily stored for several hours in the pipeline system in anticipation of an increase in demand. Line-packing is an intraday management operation that requires up to 1-day's advance notice to build up pressure to pack the lines.

Pipelines and LDCs also use interruptible sales agreements to provide additional operating flexibility in cold weather. These agreements allow pipelines and LDCs to interrupt service to nonfirm customers to ensure service to firm customers. In most cases interruptible customers are industrial and powerplant consumers who can switch to an alternate energy source. Interruptible consumers are compensated for the inconvenience by a significant reduction in the cost of gas service. In an emergency, pipelines can issue operational flow orders (OFOs) requiring a shipper to inject or

withdraw gas into or from the system at specific receipt or delivery points to ensure the continued flow of gas through the pipeline. Several hours to a full day's notice must be given before pipeline companies can implement an OFO.

Curtailment is the most severe control strategy. Under curtailment, pipeline companies may cut off transportation or storage service to their shippers in the event of a major supply or capacity disruption. However, curtailments are not used for firm transportation (service offered under contracts that anticipate no interruptions) absent force majeure. Order 636, issued by the Federal Energy Regulatory Commission (FERC) on April 8, 1992, to introduce greater competition in the natural gas industry, provides protection to high-priority users in the event of a pipeline emergency (full implementation of Order 636 began on November 1, 1993). As part of the Order 636 restructuring filing, each pipeline company was required to submit for FERC approval a priority schedule for curtailment to firm transportation shippers.

INDUSTRY ACTIONS DURING JANUARY 1994

The record demand for natural gas during the week of January 16, 1994, was met by a combination of sustained maximum production, optimization of all available storage, and import levels that set new records.

Domestic Production

As previously noted, domestic natural gas production was not hampered to any degree by the cold temperatures. Discussions with industry officials indicate that of the few disruptions in service that took place, none can be attributed to a disruption of natural gas production.

Monthly natural gas production displays little seasonal variation. Typically, January production may exceed July production by only about 5 or 6 percent. The ability to increase natural gas production on a month-to-month basis is very limited. January 1994 production, estimated at 1,620 bcf, exceeded January 1993 production by about 3 percent. (These data include production originally destined for warmer-than-normal Western markets that was diverted to the East.)

Imports

Canadian imports accounted for nearly one-third of the total gas supply in New England in January 1994, and nearly one-quarter of the supply in New York (see Table 3-2). Canadian gas is delivered to U.S. markets in the East by TransCanada PipeLines Ltd. (TCPL). Primary transportation routes from the Canadian border to eastern U.S. markets are through the Iroquois and Tennessee Gas pipeline systems (see Figure 3-2), which account for about 90 percent of the supply to Eastern U.S. markets. During the middle of the January 1994 cold spell, TCPL re-

Table 3-2. Natural Gas Imports as a Percentage of Total Gas Deliveries by State for January 1994

State	Imports (MMcf)			Total Deliveries (MMcf)	Imports as % of Total Deliveries
	Canadian	Mexican	Algerian		
New England					
Connecticut	4,835	0	556	16,780	32.1
Maine	246	0	0	777	31.7
Massachusetts	8,774	0	4,431	43,328	30.5
New Hampshire	455	0	384	2,904	28.9
Rhode Island	2,784	0	336	8,761	35.6
Vermont	1,181	0	0	1,181	100.0
Total	18,275	0	5,707	73,731	32.5
Mid-Atlantic					
New Jersey	4,358	325	78	82,479	5.8
New York	27,679	522	172	122,809	23.1
Pennsylvania	641	0	16	102,982	0.6
Total	32,678	847	266	308,270	11.0

Sources: Import data: filings submitted by importers to Office of Fuels Programs, Fossil Energy; total deliveries data: Energy Information Administration (EIA) form EIA-857. See EIA's *Natural Gas Monthly* (DOE/EIA-0130(94/09), Table 22.

ported a single-day record for exports to the United States of 3.3 bcf. Total TCPL aggregate deliveries to Canada and the United States for the month of January also established a new record, reaching 221 bcf, an increase of 17 percent over January 1993.

The 1993-94 winter was the first in which additional Canadian supplies via the Iroquois interconnection with TCPL were made available to New York and New England. In the first 3 months of 1994, the average daily take level under firm long-term imports was 645 million cubic feet (MMcf). The average take level for short-term imports was 92 MMcf. The normal operating capacity for the Iroquois pipeline is 670 million cubic

feet per day (MMcf/d). However, during January 16-22, 1994, Iroquois was able to operate all its compressors (not a normal operating procedure) to provide an additional 140 MMcf/d above Iroquois' firm transportation requirements. Most of the additional volume went to electric power generators. TCPL was able to provide Iroquois with additional natural gas in part because of cooperation from eastern Canadian LDCs. Two major LDCs relinquished some discretionary purchases to allow an increase in exports to the United States.

Canadian gas supplies via Iroquois were extended further south through an interconnection with the Tennessee Gas pipeline system. By the use of

Figure 3-2. TransCanada PipeLines and Connecting Systems

displacement with Tennessee Gas, additional gas service was made available in Pennsylvania and New Jersey.

New England is at the terminus of the only two major pipelines that transport gas from producing regions in the Gulf Coast and Southwest to the Northeastern United States. Because this reduces possible alternative supply options in the event of any supply disruptions to the south or west, New England is usually one of the first regions to experience reductions during peak-demand periods and seasonal termination of interrupt-

ible service. This unique situation has made imported LNG from Algeria an important supply source in eastern New England, particularly during peak periods. LNG also can be stored and transported, further adding to its versatility as a peaking supply source.

Distrigas of Boston, which imports LNG from Algeria, supplied a record 6.06 bcf of firm supply to New England during January 1994; it also recorded its highest daily send-out during the week of January 16. An additional tanker of Algerian LNG was delivered to Distrigas on short notice to supplement normally

scheduled deliveries at Boston. Distrigas noted that the vaporized LNG not only helped meet the region's peak demand but also made a major contribution to maintaining the system integrity of the Iroquois and Tennessee Gas pipelines by helping to avoid excessive demands on these systems.

Storage

Storage comprised approximately 29 percent of the January 1994 natural gas supply, as compared to 25 percent for January 1993. (Table 3-3 lists the actual sources of supply for January 1994.) However, storage accounted for 37 percent of total supply for the 1-week period beginning on January 15. Using the AGA weekly survey of working gas in storage, Table 3-4

shows the change in U.S. working gas levels in underground storage on a weekly basis (the AGA survey period starts and ends a day earlier than the January 16-22 period). Because warmer western regions were included in the data, the full impact of storage on the supply of gas to consumers in the Eastern United States is somewhat understated.

Actions Taken by Local Distribution Companies

The suddenness and severity of the cold weather during the week of January 16 appeared to surprise at least some in the gas industry. More than a few operations personnel expected that temperatures would begin to moderate or at least not worsen during the middle of the

Table 3-3. Sources of Natural Gas Supply for January 1994

Source	1994 Volume (bcf)	Percent of Total	1993 Volume (bcf)	Percent of Total
Conventional Production	1,634	62	1,584	66
Underground Storage	755	29	607	25
Peak Shaving	13	<1	13	<1
Imports	220	8	198	[?]
Total	2,622	100	2,402	100

Table 3-4. Sources of Natural Gas Supply for the Week of January 16-22, 1994

Source	Volume (bcf)	Percent of Total
Production	369	55
Underground Storage	253	37
Peak Shaving	3	<1
Imports	50	7

week, when, in fact, they turned much colder. This may have placed unnecessary stress on key personnel and on distribution systems that already were experiencing inordinate demand. There is some basis to believe that had the 2-day weather forecast for January 19 been more accurate, more LDCs would have used line-packing in anticipation of the demand surge. In the end, most LDCs met firm commitments through a combination of maximum storage withdrawals, including the use of peak shaving, and prudent supply and demand management.

The ability of LDCs to maintain natural gas service was further tested by rolling blackouts in Delaware, Pennsylvania, Maryland, and Virginia, which sometimes caused electrically operated compressors to shut down and created difficulties in gas system control-room operations. These blackouts reduced operations at some peak-shaving plants. The City of Richmond and the Washington Gas Light Company both reported some problems in maintaining local gas system pressures because of the electric power disruptions during the rolling blackouts. In one unusual situation, a sudden and large surge in natural gas demand that occurred when natural gas furnaces in the blackout area all came on simultaneously, when electric service resumed, almost caused an LDC serving thousands in Pennsylvania to lose pressure.

Several LDCs reported sporadic deliverability problems, and in a few instances firm service was interrupted. Most of these interruptions were related to system capacity limitations—that is, demand simply

exceeded pipeline design throughput capacity. LDCs and State and local officials made appeals for conservation of natural gas to prevent a tight situation from getting worse, and frequent news media broadcasts requested consumers to lower thermostats and reduce hot-water use.

A key element in managing demand for most LDCs was the enforcement of interruptible contracts. Under interruptible contracts, gas consumers agree to voluntarily stop gas use when requested by LDCs in return for significantly reduced prices. Whether for customers under interruptible sales agreements or transportation customers (such as gas producers who buy only pipeline transportation services), LDCs for the most part exercised interruptibility provisions to ensure the integrity of service to firm customers. This also is the one area that created the greatest number of problems: When consumers who buy gas under interruptible contracts do not cease gas use when asked to do so, higher priority customers such as residential households are in jeopardy of losing their gas supply.

The Virginia State Corporation Commission noted that several large interruptible apartment complexes in Northern Virginia that had their gas service interrupted had very little reserve fuel to meet their heating requirements—in some cases, only 2 days of supply for a gas interruption that lasted 10 days. Washington Gas made several calls to the Virginia Emergency Management Office notifying them of the precarious fuel-oil supply situation for a number of apartments. The demand for fuel oil was so great in some cases that the additional demand from interrupted

gas users could not be met by local fuel dealers. In discussions with Pennsylvania, Maryland, and Virginia officials, it was noted that fuel-oil dealers did not serve interrupted gas users to the extent those users would have preferred. Washington Gas, the Virginia Office of Emergency Services, and the Virginia State Corporation Commission all worked together to resolve the crisis by assisting interrupted gas consumers in locating and arranging for fuel deliveries.

The fact that a significant number of interruptible gas users continued to consume gas when they were asked not to do so proved to be a widespread and serious problem. Washington Gas, in testimony before the Public Service Commission of the District of Columbia, reported that 69 of 286 interruptible customers in the District consumed gas during the 10-day interruption (they did not state whether these were transportation or direct sales customers). An LDC in Pennsylvania reported that its interruptible transportation customers continued to consume gas while its interruptible sales customers went off without complaint. A contentious situation developed in Ohio when a number of interruptibles refused to stop taking gas and complained to the Governor. There were limited reports of LDCs having to go to the interrupted customer and physically shut off the supply.

Interstate Pipeline Activities

Pipeline operations from January 16 to 22 cannot be viewed in isolation but must be considered in the context of the overall distribution system,

from wellhead to burner tip. Pipelines rely on producers to get gas into the system, on underground storage operators to supplement supplies to meet peak demand, and on customer cooperation to stay within (or reduce) their design-level gas use. Pipelines must be able to communicate quickly with all these entities to properly coordinate their activities.

Effective response to the cold-weather episode by interstate pipelines is confirmed by the number of send-out records established during January 16-22. Only one pipeline, Texas Eastern, reported an interruption in firm transportation service, and that was for only 16 hours and was due to a mechanical-electrical problem when electric service on the PJM system was curtailed and Texas Eastern's backup electric generators failed to operate. This event highlights the need for coordination among electric and gas utilities in a crisis and the importance of reliable backup systems ready for use. Utilities cannot ensure undisrupted service during an extreme weather situation such as January 1994.

Electronic bulletin boards provided an early alert to changing conditions and instantaneous communication to all concerned parties. Along with other direct communication links, these bulletin boards enabled shippers and pipelines to monitor gas supply, storage withdrawals, customer demand, and capacity availability in time to respond to rapidly changing conditions. Upstream pipelines kept in close contact with their customers to respond to changing needs, which were then communicated to downstream pipelines. Marketers communicated with

pipelines on hastily arranged deals, and pipelines made arrangements to serve each others' customers. Information about random equipment failures due to extreme cold was quickly communicated to interconnecting pipelines to seek assistance. INGAA reported that 8 of the 22 pipelines they surveyed issued control directives during the week, ranging from alert day notices to operational flow orders. Actions such as these require excellent communications and a high state of readiness by all concerned parties.

GOVERNMENT ACTIONS

Government actions varied widely but were largely focused at the State and local level because most problems dealt with LDCs coping with extraordinary demand, electric power outages, and mechanical problems associated with extremely low temperatures.

Federal

The only pipeline under FERC jurisdiction that experienced any major operational problems was Texas Eastern. However, given the short duration of the emergency (16 hours on January 19), FERC assistance was not requested. No other interstate pipeline under FERC jurisdiction experienced major problems requiring FERC assistance. Therefore, FERC activities were limited to monitoring and surveying pipelines. The events related to LDCs were monitored by such DOE offices as the Office of

Emergency Management. This office closely monitored unfolding events and kept Secretary O'Leary informed on possible response options available to the Department. DOE's actions before and during the week of January 16 centered on facilitating the movement of badly needed fuel oil to consumers whose gas supply was interrupted under the provisions of supply or transportation contracts. DOE worked closely with the Department of Transportation on waivers allowing longer hours for drivers to expedite fuel-oil movements.

The Defense Fuel Supply Center (DFSC) supports the centralized acquisition of petroleum products and natural gas for the Department of Defense and the General Services Administration's (GSA) central steam production facilities in Washington, D.C. When GSA's fuel supply became marginal, DFSC became a key element in the Federal Government's response actions.

In addition to managing both petroleum and natural gas supplies at most Federal Government buildings in the Washington, D.C., area, GSA operates a local area steam supply system for the Federal buildings in the District's central (mall) area. Steam is produced at two fossil-fired plants (with oil backup) in Washington (one in Georgetown, the other in Southwest). However, in response to economic conditions, in 1993 GSA established an "interruptible" natural gas contract with the Washington Gas Light Company for these steam-producing installations so they could use gas. In the fall of 1993, because of new environmental restrictions, the

use of coal was discontinued, and low-sulfur oil became the backup fuel.

On January 19, 1994, GSA had its gas service interrupted and found itself with an inadequate on-hand stock of conforming low-sulfur oil. The Washington Gas Light Company said that it notified GSA in December 1993 that gas supplies were tight and that GSA needed to begin using alternate fuels. Under the provisions of the contract, however, GSA opted to continue to use natural gas and pay additional fees. But on January 19, Washington Gas Light ordered GSA to cease taking gas at its two steam-production plants. With the extremely low temperatures and icy and snowy conditions, obtaining a supply of the conforming low-sulfur light oil became a major problem. The loss of steam generation for the local central heat system would have resulted in severe damage to the plants and many building heating systems by allowing systems to freeze. The situation became so critical that the availability of D.C. National Guard units to assist in the delivery of fuels to GSA was discussed.

DFSC mounted an extraordinary effort to provide GSA with enough fuel to ensure that Federal buildings were adequately heated. On the 19th, DFSC mobilized Air Force refuelers at Andrews Air Force Base in Maryland to deliver JP-5 (military kerosene-type) to the two GSA facilities around-the-clock. DFSC's northeast regional office in Philadelphia then arranged the deployment of an Army petroleum supply organization from Fort Lee to Washington both to bring additional fuel oil to the area and to

assist in the delivery of fuel from local suppliers in the Washington area to the GSA facilities.

State and Local

Responses at the State level varied widely. Although only one State, Pennsylvania, issued a formal request to reduce natural gas consumption, other States issued general appeals to reduce energy consumption overall. In other States such as Virginia, where local supply problems appeared to be more widespread, no appeal was issued. In these situations, LDCs usually issued their own appeals to reduce consumption.

Natural gas at the State level is a highly regulated commodity and, consequently, most LDC actions usually require some type of approval from or coordination with State public utility commissions (PUCs). This was the case during the January cold spell, with most PUCs closely monitoring—and approving when necessary—LDC actions. LDCs generally were proactive in contacting their respective PUCs as problems became evident.

State governments activated emergency management agencies which, for the most part, are designed to respond to all types of emergencies but typically deal with natural disasters (floods, storms, and so forth). Most of their energy-emergency experience dealt with spot fuel-oil and propane shortages; prior experience with a natural gas emergency was almost nonexistent. Consequently, State emergency agencies were faced with complex situations that usually required them

to defer to PUCs and State energy offices. However, emergency agencies carried out the important role of informing State agencies of events as they developed. In Maryland and

Virginia, the emergency management offices played a pivotal role in coordinating fuel-oil deliveries to interrupted natural gas consumers.

4

Conclusions and Recommendations

Energy entities responded promptly and effectively to the extreme weather and record peak demands of January 1994. Electric and gas utilities demonstrated great technical skills and flexibility in determining the facts of many very different emergency situations and in implementing highly effective response actions. Established procedures were used when available; however, many of the response actions demonstrated much innovation and initiative. State regulatory agencies monitored response actions closely and provided appropriate and timely guidance or approval when necessary.

Followup investigations by several States, the electric utilities and the PJM Interconnection, the North American Electric Reliability Council (NERC), the Federal Energy Regulatory Commission (FERC), and others consistently praised the involved energy supply entities and did not identify any specific response action as inappropriate. These same reviewers, however, identified several additional actions that could have mitigated the extent of the crisis and made the response actions more effective. This report builds on these observations.

DOE has concluded that despite the peak and continuing high electric load levels due to the extreme low-

temperature conditions, there was no risk to the integrity of the Eastern Interconnection. The short-term use of manual load shedding (rotating blackouts) by the PJM Interconnection, Virginia Power, and North Carolina Power, although temporarily inconveniencing consumers, was appropriate and necessary to match the available supply with the continuing series of very high peak loads and hourly energy requirements. (Virginia Power and North Carolina Power are operating subsidiaries of VEPCo.) Further, except in a few isolated instances, those subjected to manual load shedding had previously been identified as not being critical public health and safety customers.

DOE has identified a number of actions taken by State and local governments—including appeals for voluntary energy conservation, closing of government operations, and transportation assistance to the energy supply entities—that were both appropriate and very effective. Likewise, actions by the U.S. Coast Guard in the Philadelphia area to break ice and maintain shipping channels were a key element in mitigating the public health and safety impacts of January 18, 19, and 20.

Fundamental to the DOE assessment were many “after-action”

reports and investigations conducted by others. The DOE staff has reviewed the available documents and concluded that all of the recommended actions in these reports are appropriate and that both the energy supply entities and the involved State and local government agencies should, if they have not done so already, develop detailed schedules to implement those actions.

Despite the fact that the report of the NERC Blue Ribbon Task Force covered only 7 hours on Wednesday, January 19, DOE believes that its conclusions and recommended actions address all actions appropriate for the bulk power supply component of the electric energy supply system (see box). The DOE review of the appropriate guidelines of the NERC Operating Manual indicated these guidelines are appropriate, and that they were effectively imple-

mented during the January 1994 crisis.

Immediately after the crisis, FERC initiated an "Inquiry Concerning Conditions in Portions of the Eastern Interconnection" in Docket EL94-23000. FERC collected data from more than 22 utilities and holding company systems on the electric energy transfers over the bulk electric transmission system. After reviewing much of the data collected by FERC, DOE concurs with the FERC conclusion that the electric power system performed well under the extreme conditions of January 1994 and that this performance attests to "the resilience of the electric power system and its ability to maintain reliable service to millions of ultimate customers." However, DOE also agrees with the FERC conclusion that there is room for incremental improvement in three areas: communications, energy

Recommendations of the NERC Blue Ribbon Task Force Report on the Events of January 1994

- 1. *Pursue better communications and information sharing***
- 2. *Develop the capability to calculate the first contingency transfer capability in real time***
- 3. *Review mutual assistance agreements among regions, subregions, pools, and coordinating groups***
- 4. *Review backup fuel inventory policies***
- 5. *Continue to improve operational coordination during emergencies***

tariffs, and transmission system ratings.

Building on and in addition to the FERC and NERC conclusions and recommendations, the DOE staff has identified the following areas in which some incremental improvements appear to be appropriate:

- Communications within the energy infrastructure
- Energy emergency situation reporting to State and Federal agencies, for both real and anticipated emergencies
- Accuracy of short-term load forecasting systems used by system operators to project hourly, next-day, and 2-day peak and energy loads based on available meteorological and other relevant data
- Specific research activities by the electric industry dealing with fuel use and electrical equipment operations in extreme cold weather and freezing precipitation
- Timely adjustments of bulk power transfer capability
- Regular joint planning and conduct of energy emergency preparedness exercises involving energy supply entities, States, and the Federal Government

These areas are discussed in detail in the following sections.

COMMUNICATIONS WITHIN THE ENERGY INFRASTRUCTURE

Both the NERC and FERC reports concluded that some improvement in communications is appropriate and

necessary, and DOE, following its own analysis, agrees that enhanced communication within and by the energy supply entities is needed. Specifically, DOE recommends that all energy supply entities across the Nation review the following areas:

- *The procedures for using the NERC telephone "Hotline."* Hotline procedures should be reviewed with the goal of making it more useful during potential emergency situations and actual emergencies. In the long term, NERC should give full consideration to replacing this limited-capability hotline with a modern, computer-driven bulletin board and significantly increasing access to it.
- *The use of ORNS.* The computerized ORNS communications system used by electric energy supply entities in the Mid-Atlantic and Northeastern United States is an excellent system that could serve as a model for similar communications systems in other areas. The NERC Operating Manual could be expanded to recognize ORNS and any other regional electric energy supply communications systems used to coordinate operations. NERC also should consider developing dedicated communications circuits that link these regional networks. Information sharing via electronic bulletin boards as mandated by FERC Order 636 was considered a key factor in mitigating the impacts of low temperatures on the natural gas supply. A similar system within the electric energy supply infrastructure may be appropriate.

- *Expansion of the IDEC system.* The DOE staff commends those involved in creating the recently developed IDEC communications system, which provides data links among many electric energy supply entities in the Northeast, Midwest, and South, and recommends further expanding this network to cover the entire Eastern Interconnection.
- *Knowledge of appropriate waivers.* The waiver of certain Federal and State government regulations, such as limits on driving hours, truck weight restrictions, and air emissions limitations, in some areas mitigated the impacts of the events of January 1994. DOE staff interviews determined that certain Federal and State government agencies can grant waivers in a timely manner, while others disclaimed any knowledge of benefits that may have been obtained from such waivers. DOE concluded that preemergency coordination is a key element and recommends that the NERC Operating Committee, the regional reliability councils, and each energy supply entity review its system emergency response procedures, identify regulatory waiver actions that may reduce the impacts of an energy supply emergency, and communicate this information to the involved government agency so that specific implementation procedures can be developed. The DOE staff will be available to assist in this activity as deemed appropriate.
- *The use of interruptible supply contracts by both electric and natural gas suppliers.* DOE supports the appropriate use of interruptible contracts. However, several consumers requiring a continuous, uninterrupted energy supply had established interruptible contracts without establishing an adequate means of alternate supply. As a result, the interruption of energy supply to residential apartment buildings and even some heavy industrial customers required special response actions by the involved energy suppliers and in some cases the State emergency management agency. DOE recommends that both the energy suppliers and the State regulatory agencies review in detail the use of interruptible contracts to ensure that critical facilities are allowed to use interruptible contracts only when they have an adequate and regularly tested backup energy supply.
- *Effect of electric interruptions on other forms of energy.* In several areas, manual load shedding actions affected the supply of other forms of energy. To prevent a reoccurrence of this situation, DOE recommends expanding communication within the energy supply infrastructure—especially at the operations level. Critical electric and gas facility operations centers, including pipeline operations, should develop a system for information sharing during crises. Depending on the media to provide this link

proved to be unsatisfactory in January 1994. The recommended system should specifically identify the energy supply entity, the geographic location of its operations center, and both commercial and other means of communications that may be available during an emergency. The ongoing activities of NERC and the Interstate Natural Gas Association of America to effect emergency coordination at the bulk supply level should be viewed as one element of this coordination.

- *Timely and accurate dissemination of information.* Energy suppliers must recognize the "Information Superhighway" and develop appropriate public plans, procedures, and systems to disseminate timely, accurate information, which is critical during energy emergency operations. DOE discovered instances where the availability of such information to responsible government and other public facility managers may have lessened the public health and safety impacts of January 1994. Both live television and radio interviews with energy supply executives or managers to validate the information being disseminated should be used. In addition, appropriate facilities should be established and staffed with an adequate number of trained operators and communicators to provide continuing information throughout the emergency.

ENERGY EMERGENCY REPORTING TO STATE AND FEDERAL GOVERNMENTS

DOE has determined that compliance with established Federal requirements for reporting certain bulk electric power supply conditions was inadequate during the events of January 1994. DOE received no reports on Tuesday, January 18, regarding the critical situation of meeting the evening peak loads on that day, nor were any reports received citing potential electric power supply problems on the morning of Wednesday, January 19. In its followup analysis, DOE learned of a number of fuel supply problems that should have been reported. This lack of official information caused DOE, FERC, and others to make a number of telephone inquiries to electric utilities, regional reliability councils, and others in an effort to accurately ascertain the situation. These calls did not fully clarify the situation or provide a basis for appropriate response actions.

The current bulk power system reporting requirements are published in title 10, section 205, of the *Code of Federal Regulations* and have been restated in a widely distributed DOE publication, *Power System Emergency Reporting Procedures*. Electric utilities, regional reliability councils, NERC, and many other interested parties are routinely included in the distribution of this publication. These current reporting requirements were established in 1989 and are modifications

of bulk electric power system reporting requirements established by the Federal Power Commission in 1966. Over the past decade, these requirements have been lessened to reduce the reporting burden—possibly to the extent that many electric power system operators are not familiar with established requirements.

During interviews with several State emergency management agencies, DOE found that many State officials also had been surprised by the energy supply crisis, and received notification only after manual load shedding operations had begun. This lack of information delayed some emergency response actions.

Electric energy suppliers, and the entire energy infrastructure, must ensure that their operations staffs understand the critical public health and safety impacts of a major energy supply outage or curtailment. Likewise, the Federal and State governments must ensure that energy suppliers understand the potential response capabilities and actions that may be taken to mitigate the effects of an energy emergency. These concepts must be understood within the energy supply infrastructure to be mutually supportive and not as an indication of failure.

DOE should review its requirements and procedures for reporting bulk power system emergencies, make any changes that will minimize the reporting burdens on the involved energy suppliers, and ensure that State emergency management agencies are fully informed regarding any potential or actual energy supply crisis. Consideration should be given to concurrent joint reporting of emergency data or possible reports by

the energy infrastructure to States, so that State governments and the Federal Government receive the same information at the same time.

REAL-TIME POWER-TRANSFER-LIMIT ADJUSTMENTS

On the morning of January 19, two significant ad-hoc operational actions were taken to make more power available to PJM and Virginia Power—one by PJM and the New York Power Pool, and the other by the Florida Electric Power Coordinating Group and the Southern Company System. In both actions, the first contingency incremental transfer capability (FCITC) limit was significantly increased after it was recalculated following special joint systems analyses. These analyses reflected the actual available and operating generation, the actual load requirements, and the actual loading on the bulk transmission lines connecting the New York Power Pool and PJM and those connecting the Southern Company System to utilities in Florida. Both actions allowed additional power to be transferred to the deficient areas. The NERC Blue Ribbon Task Force recognized these actions as appropriate and acknowledged that the increased power transfer capabilities were a factor in the curtailment of all of the manual load shedding actions in the early afternoon of January 19. In light of this now “proven” capability to recalculate the FCITC to reflect current real system conditions, DOE agrees with the NERC recommendation that all utility

operating procedures be modified to include provisions for such special studies in power supply crises and that the necessary technical equipment and systems be made available to operating staff as required.

ACCURACY OF SHORT-TERM LOAD FORECASTING

The inability of energy suppliers' short-term load forecasting systems to accurately relate their peak load requirements for the next hour, the next day, and the next 2 days—in particular, determining the incremental load requirements for each degree of temperature drop below zero—appears to have been a contributing factor to the need for manual load shedding.

DOE believes that if the peak load requirements for Wednesday morning, January 19, had been accurately forecast on Tuesday evening, many electric utility system operations managers would have taken actions to manage their power supply systems differently—specifically, steps to use pumped storage capacity and available fuel supplies more effectively and special efforts to increase generator availability. Several utility operators interviewed by DOE concurred, stating that the Wednesday morning load probably could have been supplied with no rolling blackouts if the peak loads had been accurately forecast. Although the significant differences between forecast and actual minimum temperatures made it difficult to predict load requirements with reasonable accuracy, the Department nonetheless

recommends that electricity suppliers review and make appropriate adjustments to their short-term peak load forecasting systems to reflect the experiences of January 1994. Ameliorating this situation requires no additional legislation by either the Federal or any State government.

RESEARCH ACTIVITIES

DOE has concluded that some additional research to enhance the delivery of electric energy during extremely low temperatures is probably appropriate. Most of the many "after-action" reports at least somewhat support this conclusion.

Specifically, DOE recommends that electric suppliers in low-temperature areas of the Nation review their procedures for dealing with such situations and make improvements where and as appropriate. Frozen coal piles and conveyor belts and congealed oil in pipelines were significant factors in the energy disruptions of January 1994. The DOE staff discovered that some electric suppliers had minimal problems with these situations, while others had major problems. The lessons learned must be shared with all appropriate energy entities, and research documenting the situations and identifying possible mitigation actions is needed.

Electrical equipment operations in very low temperatures also requires research. There were a number of extra-high-voltage circuit breaker trips that exacerbated the energy supply situation. Most of these trips involved circuit breakers that used SF-6 (sulphur-hexafluoride) gas as the insulating medium. The DOE staff

recognizes that this has been a concern since SF-6 circuit breakers were introduced in the 1960s and that a number of design modifications have been made and special operating procedures implemented. However, the persistence of the problem requires further research—in particular, examining the operations of all types of circuit breakers in low-temperature situations in detail and reviewing all types of electrical equipment, including the instrumentation at generating stations. The goal should be a well-documented technical paper with detailed actions to mitigate operational problems in low temperatures. NERC should consider coordinating this activity and possibly providing some oversight; and it must ensure this information is widely distributed through its Operating Manual and other NERC publications.

REGULAR, COORDINATED ENERGY EMERGENCY EXERCISES

Nearly all who were interviewed agreed that the longstanding DOE sponsorship of energy-emergency-preparedness exercises involving States and energy suppliers was a significant factor in the response actions of January 1994. The DOE staff verified that the personal relationships among the various State energy and emergency management office personnel established by these exercises were instrumental in many of the successful actions of January 1994.

Based on this input, the DOE staff recommends continuing these exercises regularly, and that all elements of the energy infrastructure become involved, as well as State emergency management offices and regulatory agencies. Even if no Federal action is requested or taken, these exercises enhance the emergency preparedness of States and the energy infrastructure.

Overview of U.S. Electric Power Supply

At the end of 1993 the electric generating industry in the United States was composed of 3,212 utilities that can be grouped into four ownership categories and some 1,200 nonutility generators (NUGs). Some utilities are integrated from generation to end-user; that is, they own generating plant, transmission, and distribution capability and have customer franchises granted by the states or local jurisdictions in which they operate. Other utilities only participate in one part of this business, such as a utility that participates only in the wholesale market, providing generation and transmission services, or utilities that participate only in the end-user market, buying power from others and distributing the power to end-use customers.

Utilities are usually categorized as investor-owned, publicly owned (for example, municipal utilities and public utility districts), cooperatively owned, or federally owned. In addition to utilities, nonutility generators (such as qualifying facilities and exempt wholesale generators) also supply power to the grid. The largest group of utilities is the publicly owned group (2,007). However, publicly owned utilities supplied only 9 percent of net utility electricity generation in 1993. Many of these utilities do not own generating capability, but buy their power from others.

The next largest classification of utilities is the cooperatives, which are utilities owned by their own customers. The cooperatives numbered 941 and represented less than 5 percent of net utility generation in 1993. Most of the cooperatives buy their power from others and distribute it to their members.

There were 254 investor-owned utilities (IOUs) at the end of 1993. These utilities are mostly integrated utilities and accounted for 79 percent of the net generation in 1993. The 10 Federal utilities (such as the Tennessee Valley Authority and the Bonneville Power Administration) are mainly power wholesalers, and provided 8 percent of net utility generation in 1993. Nonutility generators supplied 181,515 gigawatthours (GWh) in 1993 to augment the total net utility generation of 2,882,525 GWh.

In addition to U.S. generation, Canada and Mexico supplied a net of 28,427 GWh to customers in the United States.

Today, most electric utility systems are interconnected with other systems to form *networks*. These networks evolved as a result of increases in system size and interconnections over the last 100 years. The evolution of the industry led to the current situation, in which power supply in the 48 contiguous States is provided by three large integrated networks: the Eastern Interconnection, the

Western Interconnection, and the Texas Interconnection. The Eastern Interconnection extends into Canada and has ties to the Hydro-Quebec System (also known as the Quebec Interconnection). The Western Interconnection extends into Canada and Mexico. The Texas Interconnection is confined (by the choice of Texas utilities) to a portion of the State of Texas and has only minor interconnection capacity with the Eastern and Western groups. For economic reasons, interconnection capacity between the Eastern and Western Interconnections is limited. Essentially, the three large interconnections can be considered to operate in isolation from each other. Within each of the networks a change in demand or generation will be perceived throughout the entire group of interconnected utilities of that network. If no transmission constraints existed, demand at any point in an interconnection could be supplied by any generating unit within the group.

To facilitate the operation of such large, complicated networks, groups of utilities within each interconnection agreed to combine some features of their daily operations. Each group, called a "control area," is responsible for supplying the aggregate demand of the systems within the group by means of the aggregate generating capacity of the group. This capacity is in most cases supplemented by purchases from utilities outside the control area. If an imbalance occurs within the control area between total supply and total demand, utilities within the control area are responsible for correcting the imbalance to keep generation and transmission facilities from becoming overloaded. Each control area has its own control center (a facility from which the loading of generating units is adjusted or directed to meet internal needs) as well as commitments to buy or sell power to systems external to the control area. The loading adjustments, depending on the facilities and agreements among the control area members, may be made directly by operators in the control center, or they may be effected, at the direction or request of the control center operator, by personnel of the systems owning the generators. The Eastern Interconnection has about 100 separate control areas that normally communicate directly with all adjacent control areas.

B

Glossary of Terms and Acronyms

This glossary is intended only as an aid to understanding the text of the report; it is not intended as an exhaustive definitive dictionary of terminology for the electric power and natural gas industries. The definitions given are based on those in glossaries published by the Energy Information Administration (EIA), the North American Electric Reliability Council, the Edison Electric Institute, the (former) Federal Power Commission, and other sources but may not follow the exact wording of those publications. In some instances the definitions have been expanded on the basis of information in the technical literature of electric power systems. It is intended that this glossary be used only in conjunction with this report, not as a substitute for any other glossary or dictionary.

ACRONYMS

ACE	(Atlantic City Electric Company) A member of PJM.
AEP	(American Electric Power Company) A holding company that has seven electric utility operating subsidiaries in ECAR.
APPA	(American Public Power Association) An electric power industry trade association whose members are electric utilities owned by governmental agencies (Federal, State, local).
APS	(Allegheny Power System) A holding company that has three electric utility operating subsidiaries in ECAR.
BGE	(Baltimore Gas and Electric) A combined utility serving the control areas of Maryland. Its electric operations function within PJM.
CGE	(Cincinnati Gas & Electric Company) A combined gas and electric utility. The electric system operates as a member of ECAR.
CPL	(Carolina Power & Light Company) A utility in SERC.
DLCO	(Duquesne Light Company) A utility in ECAR.

Duke	(Duke Power Company) A utility in SERC.
EEI	(Edison Electric Institute) An electric power industry trade association whose members are privately owned electric companies.
EKPC	(East Kentucky Power Cooperative) A cooperatively-owned electric utility in ECAR.
GPU	(General Public Utilities) A holding company with three electric utility operating subsidiaries; GPU is a member of PJM.
HE	(Hoosier Energy Rural Electric Cooperative, Inc.) A utility in Indiana.
IPL	(Indianapolis Power & Light Company) A utility in ECAR.
JCPL	A subsidiary of General Public Utilities (GPU)
METED	(Metropolitan Edison Company) A subsidiary of GPU.
NEPOOL	(The New England Power Pool) A group of electric utilities in New England, bound by contract to operate as a power supply entity, under agreed-upon rules.
NERC	(North American Electric Reliability Council) An electric power industry association whose members are the Regional Electric Reliability Councils. NERC's function is to improve the reliability of electric power supply in North America.
NRECA	(National Rural Electric Cooperative Association) An electric power industry trade association whose members are rural electric cooperatives and some public power districts.
NUG	(Non-utility generator) A generating unit, powerplant, or company that produces electric power for sale to electric utilities per established contracts developed under State regulatory agency oversight. A NUG company is not an electric utility and is not allowed to sell electric power at retail.
NYPP	(The New York Power Pool) A group of electric utilities in New York State, bound by contract to operate as a power supply entity under agreed-upon rules.
OE	(Ohio Edison Company) A utility in ECAR.

Pepco	(Potomac Electric Power Company) An electric utility member of PJM.
PJM	(Pennsylvania-New Jersey-Maryland Interconnection) A power pool that has 11 electric utilities as members; the service areas of the members include the District of Columbia, all of Delaware and New Jersey, part of Maryland and part of Pennsylvania, and that part of Virginia on the southern tip of the Delmarva Peninsula.
PPL	(Pennsylvania Power & Light Company) An electric utility member of PJM.
PSC	(Public Service Commission) See PUC.
PSEG	(Public Service Electric & Gas Company) An electric utility member of PJM.
PUC	(Public Utility Commission) A State agency that regulates the rates, and certain other aspects, of public utilities in that State and that may have other, related powers, as granted by the State legislature. Some State regulatory agencies are called "Public Service Commissions," "State Corporation Commissions," or "Public Utility Boards."
SOCO	(Southern Company) A holding company based in Birmingham, Alabama; members are Georgia Power, Alabama Power, Mississippi Power, Gulf Power, and Savannah Power operating subsidiaries.
TVA	(Tennessee Valley Authority) An agency of the U.S. Government, with electric utility functions and other responsibilities; operates over a seven-state area in SERC, selling wholesale power to cooperatives and municipal utilities.
VEPCo	(Virginia Electric and Power Company) An electric supply entity in the VACAR subregion of SERC with Virginia Power and North Carolina Power as its operating elements
VP	(Virginia Power Company) An operating element of the Virginia Electric and Power Company

REGIONAL ELECTRIC RELIABILITY COUNCIL

An association of electric utilities whose purpose is to improve reliability and adequacy of electric power supply in the total area served by the member utilities, by means of coordinated planning and operation. The Regional Electric Reliability Councils in the United States are:

ASCC	Alaska Systems Coordinating Council
ECAR	East Central Reliability Coordination Agreement
ERCOT	Electric Reliability Council of Texas
MAAC	Mid-Atlantic Area Council
MAIN	Mid-America Interconnected Network
MAPP	Mid-Continent Area Power Pool; includes Canadian systems
NPCC	Northeast Power Coordinating Council; includes Canadian systems
SERC	Southeastern Electric Reliability Council
SPP	Southwest Power Pool
WSCC	Western Systems Coordinating Council; includes Canadian and Mexican systems

DEFINITION OF TERMS

Actual Path	The actual route of power flow (usually multipath) over operational transmission lines.
Availability	A condition that allows equipment to be used at the discretion of the system operator. Availability is expressed numerically as the ratio of the time period during which an item of equipment was available for operation to the total time period under consideration. For example, if a generator could have been operated for 30 days (not necessarily consecutive) in 1 year, the availability for that year would be expressed as 30/365, 0.0822, or 8.22 percent.
Combustion Turbine	A turbine for which the driving power is the gaseous product of the combustion of a fuel, which may be natural gas, light oil, or gas derived from coal. The turbine can be used to drive a compressor associated with a pipeline, or as an electric generator.

Contract Path	The apparent transmission system route (usually the route for the majority, but not all, of the contracted power flow) over which purchased power is <i>presumed</i> to flow, for contractual purposes.
Control Area	<p>A single electric energy supply or a group of interconnected electric energy supply entities where the combined system aggregate electric demand is expected to be equal to the sum of aggregate generation plus the net of aggregate scheduled purchases and sales of electricity by the systems within the control area.</p> <p>Changes in aggregate demand are met by changes in aggregate generation and temporary purchase and sale transactions with systems outside the control area, while scheduled purchases and sales are maintained as contracted for.</p>
Control Center	A facility which serves as the "nerve" center for a specific energy supply entity or group of energy supply entities with the mission to oversee system operations so as to achieve reliability criteria, meet economic goals, and provide the man-machine interface for the operations of specific facilities to include scheduling maintenance, switching the facilities to and from service, and developing both the routine and emergency reports required by energy supply entity managers and government agencies.
Demand (Electrical)	The time rate at which electric energy is delivered or used. Peak demand is the highest 1-hour rate at which energy is delivered or used during a specified period; it is usually computed as the greatest amount of electric energy (in kilowatthours or megawatthours) delivered during any 1-hour period of a day, week, month, season or year. For instance, the greatest number of megawatthours delivered during any one hour in the course of a calendar year is referred to as the annual peak demand in megawatts.
Deliverability	The volume of gas that can be delivered in a specified time period, taking into account production, storage, and pipeline capacity.
Demand (Natural Gas)	The quantity of natural gas delivered by a system over a 24-hour period.

Direct Control Load Management	The magnitude of the demand that can be interrupted by a system operator, for a short time, under preexisting agreements, in emergency situations when the utility determines that the capacity available to it may be insufficient to supply the total demand on the system and maintain system integrity. This option is designed to disconnect groups of residential loads such as air-conditioners, hot water heaters, swimming pool pumps, or similar devices that can be switched off for large groups of customers by the system operator via special control equipment, without affecting the supply of electricity for lighting or small appliances for those customers. This type of controlled short-term load reduction is not considered to be "interruptible" load, although the large-scale effect on total system demand is similar.
Forced Outage	The unexpected automatic or manual removal of equipment from service due to malfunction.
Gas Turbine	(see Combustion Turbine)
Generating Plant	A location at which there are one or more generating units; the units may be of different types and sizes. All the units at a given plant are generally operated by a single entity; however, for some plants the ownership of the units and of the capacity are shared among several utilities. The operating entity may be one of the owning utilities or may be an "Operating Company" organized by the owners for the purpose of operating all the units in the plant.
Generating Unit	An assembly of devices, equipment and machinery designed to produce electric energy from energy in some other form (moving water, nuclear fission, combustion of coal or other material, sunlight, wind, or geothermal sources).
Hydro Unit	A generating unit for which the source of energy is water, either flowing in a stream or from a pond, lake, or reservoir.
Installed Reserve	The difference between the total demonstrated net generating capacity of the units controlled by a system and that system's projected peak demand.

Interruptible Demand (or Interruptible Load)	Demand that can be interrupted (discontinued completely) or reduced by the system control operator or by the customer at the request of the operator, when the utility considers a reduction of load is necessary, under the terms of a contract under which the customer receives electric service. "Interruptible contracts" are not standardized; the contract conditions are generally different for different utilities, and may be different even for different customers of any one utility. Interruptible contracts are usually designed for use with industrial customers. In consideration of the fact that the power supply may be subject to curtailment or cessation (which may adversely affect the customer's operations) the utility charges a rate lower than that which would ordinarily be charged. The interruptibility conditions may be the length of notice to be given to the customer that service will be curtailed or interrupted, the duration of the interruption, the number of instances during a specified period (one month, one year, or other) that the interruptibility option may be exercised by the utility or other factors. A usual condition for implementation of the interruptible contract terms is the existence of a supply emergency on the utility's system.
Load	A term generally used as a synonym for demand, but also sometimes for energy supply.
Load Dispatcher	An individual who coordinates the operation of generating units, usually by means of the devices in a control center.
Nuclear Unit	A generating unit for which the source of energy is nuclear fission. The U.S. Nuclear Regulatory Commission uses the term "plant" instead of "unit."
Operating Reserve	The actual reserve generating capacity in excess of demand that a system has available at any time. The term may include spinning reserve, 30-minute reserve, and other available types.
Peak Demand	See Demand.
Power Pool	Two or more electric systems that coordinate their planning and operations, usually to operate as a single control area. The detailed parameters require FERC approval. A power pool contract may include the following: (1) an agreement to share reserve capacity;

(2) centralized dispatch of the generating units of all parties; (3) free flow of power among the parties without the need for advance agreements as to magnitude, timing, and cost; (4) sharing of the cost and output capacity of new generating units; (5) agreement to contribute a specified amount or percentage of reserve capacity to the pool; and (6) other relevant matters. The systems that form the pool are in the same geographical area and may all be subsidiaries of one holding company or may be individual electric utilities with no intercompany contracts other than the pool agreement.

Pumped Storage

A hydroelectric energy generation site whereby water is pumped via a reversible motor generator to an elevated reservoir during nonpeak periods and stored. When additional capacity is needed, the water is released to generators located at a lower level and the output electric energy is sent to the system. Scheduling the pumping and generating times for a pumped storage facility is complex and dependent on many factors.

Purchase

A transaction between two or more utilities for a specified amount of capacity and/or energy from the other for a specified time period at a negotiated price.

Reserve

A general term used to state the difference between generating capacity and the current control area or system peak load demand. It must be qualified to indicate whether it refers to planning reserve or operating reserve, and there are categories within these general terms.

Rotating (Rolling)
Blackout

An element of an electric energy supply entity emergency plan whereby the service to a specific group of customers is manually disconnected for a stated period (usually 5 to 30 minutes) and is then restored while service to a different group is disconnected. The purpose of rotating (rolling) blackouts is to reduce the control area's peak load so it matches the available power supply.

Sale	A transaction between two utilities in which one sells a specified amount of power to the other for a specified time period at a negotiated price, so that the purchasing utility may resell the power to its customers. Such sales may be firm and/or nonfirm such as emergency and economy energy transactions and may be capacity or energy only.
Scheduled Outage	Removal of equipment or other components from service according to a coordinated prearranged schedule.
Sendout	The daily volume of natural gas that an LDC puts into its system to meet customer needs.
Steam Unit	A generating unit that uses steam to operate a turbine (or turbines) that in turn provides mechanical energy to an electric generator, which produces electric energy.
System Operator	An individual at a control center with responsibilities for specific functions within the control center. Some system operators perform load dispatch oversight operations while others perform oversight duties for the bulk power transmission system and switching. Others perform planning and/or maintenance coordination functions.
Throughput	Actual or estimated volume of natural gas that may be carried by a pipeline over some period of time.
Voltage Reduction	The directed reduction by a utility or control area of the system voltage level to a lower voltage such that consumer delivery voltages and nominal power requirements are less. Usual system or control area voltage reductions as a percentage of nominal voltage on the circuit are 3 percent and 5 percent. By law, such reductions must be reported to the U.S. Department of Energy.

Chronology: January 13–20, 1994, Cold-Weather Events

ACRONYMS USED IN THIS CHRONOLOGY

ACE	Atlantic City Electric Co.
AEP	American Electric Power System
APS	Allegheny Power System
BGE	Baltimore Gas & Electric Co.
CNG	Consolidated Natural Gas Co.
CP&L	Carolina Power & Light Co.
DLCO	Duquesne Light Co.
Duke	Duke Power Co.
HE	Hoosier Energy Rural Electric Cooperative, Inc.
IPL	Indianapolis Power & Light Co.
JCPL	Jersey Central Power & Light Co.
MET ED	Metropolitan Edison Co.
NCP	North Carolina Power
NEPEX	New England Power Exchange
NYPP	New York Power Pool
PECO	PECO Energy Co.
PEPCO	Potomac Electric Power Co.
PJM	Pennsylvania-New Jersey-Maryland Interconnection
PPL	Pennsylvania Power & Light Co.
PSEG	Public Service Electric & Gas Co.
SOCO	The Southern Company System
TVA	Tennessee Valley Authority
VEPCo	Virginia Electric and Power Co.

APPENDIX C. CHRONOLOGY: JANUARY 13-20, 1994, COLD-WEATHER EVENTS

	Time	System	Event
Thursday, January 13, 1994	1617	All PJM utilities	Cold weather message issued by PJM control center.
Friday, January 14, 1994	1020	All PJM utilities	Cold Weather Alert for Sunday, January 16, 0500-2100 hours.
	1020	PEPCO (PJM)	All generating stations ordered to have combustion turbine units staffed from 0400 hours on January 15 through January 18.
Saturday, January 15, 1994	0800	PSEG (PJM)	All interruptible gas customers ordered to be off-line.
	1338	PECO (PJM)	Declares Cold Weather Alert
Monday, January 17, 1994	1000	PECO	Schuylkill No. 1 reduces generation to conserve fuel
	2000	APS	Severe condition alert declared
	2015	PECO (PJM)	Schuylkill No. 1 steam generating unit, 166 MW, oil fuel with no alternate fuel, out of service because of lack of fuel.
	2200	PP&L (PJM)	Martins Creek units 3&4 limited to 173 MW to conserve oil supplies
	2330	PP&L (PJM)	Conemaugh No. 1 (850 MW) returned to service
Tuesday, January 18, 1994	0049	All PJM utilities	500-kV circuit breaker on Wescosville West line in Pennsylvania tripped because of air system leak.
	0400	VEPCo	CNG natural gas pipeline notifies VEPCo that the natural gas supply to Chesterfield No. 7 generating unit (170 MW) will be curtailed. Unit fuel supply is switched to heating oil until an additional gas supply source is found on January 19. No unit outage.
	0540	APS	Hatfield Unit No. 1 (555 MW) trips due to tube leak.
	0745	MET ED (PJM)	Titus No. 1 steam generating unit, 79 MW, coal-fired, out of service because of lack of fuel (oil).
	1137	PECO (PJM)	Cold Weather Alert declared.

Time	System	Event
1200	PECO (PJM)	Croydon Combustion Turbines No. 12, No. 32, No. 41, and No. 42 reduce generation to conserve oil.
1500	ACE (PJM)	Deepwater No. 4 steam generating unit, 54 MW, oil-fired, no alternate fuel, out of service because of lack of oil.
1535	ACE (PJM)	DuPont No. 7 (Deepwater 7) generating unit, 24 MW, out of service because of lack of fuel (oil).
1629	All PJM utilities	Order issued for maximum emergency operation of all steam generating units.
1645	All PJM utilities	PJM Operating Committee teleconference to review load conditions.
1645	VEPCo	Possum Point No. 1 steam generating unit, 74 MW, oil fuel, no alternate fuel, tripped because of operator error.
1648	All PJM utilities	Warning issued for system voltage reduction.
1705	All PJM utilities	Order issued for maximum emergency generation operation for combustion turbine units.
1708	All PJM utilities	Warning issued for manual load shedding.
1719	BG&E (PJM)	Eight combustion turbine generating units, total 136 MW, natural gas-fired, no alternate fuel, out of service because of curtailment of natural gas supply.
1726	APS	Five-percent system voltage reduction ordered by APS System Operator on Monongahela and West Penn Power System.
1735	APS	APS System Operation Office initiates action to contact industrial and large commercial customers and request voluntary load reductions.
1740	APS	Five-percent voltage reduction order on Potomac Edison System
1800	JCPL (PJM)	South River nonutility generator, 252 MW, out of service because of lack of natural gas.

	Time	System	Event
	1935	PP&L (PJM)	Brunner Island No. 1 (321 MW) tripped due to frozen drum line.
	2031	APS	Wylie Ridge 500-kV breaker locks out.
	2215	APS	Five-percent voltage reduction canceled.
	2335	ACE (PJM)	Mickleton No. 1 generating unit, 59 MW, natural gas-fired with kerosene as alternate fuel, out of service because of unavailability of natural gas and lack of kerosene.
Wednesday, January 19, 1994	N.A.	Governor of NJ	State of Emergency declared.
	0012	All PJM utilities	Warning for manual load shedding canceled.
	0012	All PJM utilities	Warning for voltage reduction canceled.
	0019	All PJM utilities	Maximum emergency generation condition canceled.
	0235	APS	Kammer-Harrison-Ft. Martin 500-kV transmission line tripped because of failure of a "Transfer Trip" relay. This was not a weather-related problem.
	0245	APS	Two 500 kV circuit breakers at Fort Martin trip and lock out due to low air pressure.
	0301	PJM system	Homer City 345/230 kV north autotransformer tripped.
	0322	PJM system	Conemaugh No. 2 generating unit, 850 MW, coal-fired, no alternate fuel, output shared among the PJM utilities, tripped due to circulating pump problems.
	0321	All PJM utilities	Request 100 percent spinning reserve to be synchronized.
	0335	All PJM utilities	100 percent spinning reserve request cancelled.
	0351	All PJM utilities	Supplementary Status Report information requested.
	0355	All PJM utilities	Primary reserve alert and warning issued.
	0355	All PJM utilities	Voltage reduction and voluntary customer load curtailment alerts issued.

Time	System	Event
0356	All PJM utilities	Homer City-Watercure 345-kV transmission line in New York tripped.
0400	PSEG (PJM)	Burlington No. 10 generating unit, 170 MW, out of service because of lack of fuel.
0400	VEPCo	Gravel Neck No. 2 combustion turbine generating unit, 28 MW, oil fuel with natural gas as alternate, tripped.
0405	All PJM utilities	Alburtis-Juniata 500-kV transmission line in Pennsylvania opened when its 500-kV circuit breaker at Alburtis trips.
0410	All PJM utilities	The 345/230-kV "South" autotransformer at Homer City in New York operating in overload condition.
0416	VEPCo	Possum Point No. 1 steam generating unit, 74 MW, oil fuel, returned to service. (This unit had tripped on Tuesday, January 18, at 1645 hours because of operator error.)
0420	All PJM utilities	Maximum emergency generation from combustion turbines requested.
0436	All PJM utilities	Load management steps 1 and 2 alert issued. Order issued for 5 percent voltage reduction at 0630.
0446	All PJM utilities	Homer City-Watercure 345-kV transmission line returned to service relieving overload on Homer City 345/230 kV and South Autotransformer. This line had tripped this morning at 0356 hours.
0500	APS	Order issued for immediate 5 percent system voltage reduction on Potomac Edison System.
0503	All PJM utilities	Maximum generation from all combustion turbines requested.
0506	All PJM utilities	Manual load-shed warning issued.
0508	Pepco (PJM)	Benning No. 15 steam generating, 275 MW, oil-fired, no alternate fuel, tripped because of tube leak.

Time	System	Event
0515	All PJM utilities, VEPCo, APS	Level 1 of Reliability Coordination Plan declared to be in effect based on heavy flows on APS transmission system. No action taken. Flows are manageable.
0515	IPL	System Operations Department authorized actions to initiate contacts with industrial and large commercial customers and request voluntary load reduction.
0530	VEPCo	System Operations Department authorized initiation of public appeals for electric power conservation.
0530	DLCO	System Operations Department authorized initiation of public appeals for electric power conservation.
0600	All PJM utilities	Operating Committee teleconference reviewed situation and the need for emergency procedures between 0800 and 1000.
0600	VEPCo	Gravel Neck No. 1 combustion turbine generating unit, 17 MW, oil fuel with natural gas as alternate, tripped because of a combustor problem.
0600	PECO (PJM)	Issues Cold Weather Alert.
0600	All PJM utilities	PJM System Operator ordered load management curtailment steps 1, 2, 3, and 4.
0600	Pepco (PJM)	Radio/TV appeals for electric power conservation initiated in Washington, DC, and company load management programs implemented.
0608	CPL	Initiated implementation of water heater demand-side load management plan.
0615	CPL	Initiated call on NERC "Hot Line" requesting assistance, and initiated action to effect a 5-percent voltage reduction as ordered by System Operations Department.

Time	System	Event
0615	VEPCo	Notified APS that the 200-MW power delivery specified in an existing load diversity contract to begin at 7 A.M. would not be available that day.
0618	APS	Wylie Ridge-Harrison 500-kV transmission line trips because of low air pressure in a circuit breaker.
0623	VEPCo	Implemented 5-percent nominal system voltage reduction as directed by the System Operations Office.
0631	TVA	Initiated action to notify customers that economy surplus "B" was being cancelled.
0645	All PJM utilities	Initiated actions to effect a 5-percent voltage reduction as ordered by the PJM System Operator.
0645	All PJM utilities	Operating Committee teleconference reviewed current situation. The Committee was informed of the imminent implementation of voluntary customer load curtailment and the issuance of radio/TV appeals for electric power conservation.
0645	TVA	Initiated action to notify customers that economy surplus power deliveries under option "A" were being curtailed.
0645	APS, all PJM utilities, and VEPCo	Initiated actions to implement Level II of the Reliability Coordination Plan. No action taken. Power flows manageable.
0653	All PJM utilities	Hosensack-Quarry 230-kV transmission line in Pennsylvania trips.
0700	VEPCo	Northern Neck No. 3 and No. 4 combustion turbine generating units, 19 MW each, oil fuel, no alternate fuel, tripped because of instrument indication of high temperature on the main winding of the transformer serving both units.

Time	System	Event
0700	All PJM utilities	PJM System Operator ordered the beginning of radio and TV appeals for voluntary electric power curtailment.
0700	DLCO	System Operations Dept. directed that actions be implemented to contact industrial and large commercial customers to request voluntary electric power conservation.
0701	APS	Transmitted phone-mail message to the U.S. Department of Energy's Office of Emergency Management requesting assistance in obtaining a load reduction at the Department's nuclear processing facility in Portsmouth, Ohio.
0702	SOCO	Generating unit No. 4, 900 MW, coal-fired, at Plant Bowen on the Georgia Power Company system tripped; unit No. 2 at this plant experienced a run-back of about 500 MW.
0705	All PJM utilities	Order issued for all PJM member utilities to shed all nonessential building loads.
0705	All PJM utilities	The PJM System Operator ordered issuance of voluntary load curtailment request to customers.
0705	All PJM utilities	The PJM System Operator ordered manual shedding of 500 MW of load by the system.
0705	All PJM utilities	Manual load shedding begun.
0710	DOE	DOE's Portsmouth plant received request from supplier to drop load throughout the day.
0713	Duke	Water heater control program activated.
0713	PP&L (PJM)	Martins Creek No. 1 tripped while supplying 140 MW due to frozen drum level line.
0720	PEPCO (PJM)	Manually controlled rotating load shedding begun.
0733	TVA	Economy surplus power customers (Option "E") curtailed.

Time	System	Event
0739	PPL (PJM)	PJM Control Center notified that all 230-kV circuit breakers at the Susquehanna 230-kV substation have leaks and could trip at any time.
0741	All PJM utilities	500 manual load shedding order cancelled.
0743	APS	Initiated action to make public appeals for electric power conservation.
0753	Pepco (PJM)	All load that had been shed manually is restored.
0800	All PJM utilities	Initiated sale of 500 MW of emergency power to VEPCo.
0800	TVA	Initiated distribution load reduction programs and public appeals.
0800	EKPC	Initiated actions for public appeals to conserve electric power and to make direct appeals to industrial and large commercial customers for electric power conservation.
0800	CGE OE	Action taken to initiate direct appeals to industrial and large commercial customers for electric power conservation.
0800	APS	Kammer-Harrison-Ft. Martin 500-kV transmission line returned to service. This line had tripped this morning at 0235 hours.
0802	Duke	Initiated implementation of interruptible service program.
0815	All PJM utilities VEPCo	Sale of 500 MW of emergency power to VEPCo cancelled; actual delivery was 167 MWH.
0815	APS	Phone-mail message received by DOE, and action initiated to obtain approvals and notify the Portsmouth, Ohio, facility to reduce its electric power requirements.
0821	NYPP	Five percent Quick Response voltage reduction in NYPP accomplished in response to a request from PJM to enhance power deliveries from NYPP to PJM.
0823	VEPCo	System Operator orders manual shedding of 400 MW of firm load.

Time	System	Event
0825	DOE	Portsmouth plant initiated 100-MW load drop.
0828	APS	Control center requested all 500-kV substations be manned.
0830	PJM	Notified APS it was selling 1,000 MW to other systems.
0830	All PJM utilities	Joint teleconference of PJM Management and Operating Committees to review status of system.
0830	APS	Intercepted 359 MW of sale from AEP to PECO for own needs on emergency basis.
0830	AEP	Issued public appeals for electric power conservation.
0845	VEPCo	System Operator orders manual shedding of an additional 400 MW of firm load.
0902	AEP	System voltage reduction ordered to reduce system load.
0915	HE	Directed action to appeal to industrial and large commercial customers for electric power conservation and initiated public appeals for electric power conservation.
0922	All PJM utilities	PJM operators order manual load shedding of 500 MW.
0930	PPL (PJM)	230-kV circuit breaker on the Sunbury 230-kV transmission line trips.
0934	SOCO	Georgia Power Co.'s Plant Bowen Unit No. 2, 700 MW, coal-fired, tripped.
0934	PJM	Requested NYPP to implement manual system voltage reduction to enhance amounts of power available for export to PJM.
0936	NYPP	In response to PJM request, NYPP directed its member utilities to implement manual voltage reduction such that additional power could be made available for export to PJM.

Time	System	Event
0940	All PJM utilities	NYPP notifies PJM that the export stability limit has been reached.
0941	SOCO , OG, MEAG, and CD	Plant Vogtle No. 1 nuclear unit, 1,200 MW, tripped; SOCO recalls 800 MW of sales to other utilities.
0944	All PJM utilities	PJM requests NYPP to restudy their export stability limitation.
1000	Pepco (PJM)	Load management programs terminated.
1010	All PJM utilities	PJM System Operator ordered an additional 500 MW of load to be shed; total was now 1,000 MW.
1010	PJM	Homer City North 345/230 auto-transformer returned to surface (had tripped at 0301).
1020	APS	Received notification from the DOE Portsmouth facility that their load requirements had been reduced by 185 MW.
1100	VEPCo	200 MW of manually shed load ordered restored.
1106	NYPP	Terminated its 5 percent Quick Response voltage reduction.
1112	NYPP	Completed technical studies and rerated intersystem transfer from NYPP to PJM.
1114	NYPP	NYPP notifies PJM that power export stability limit has been increased to 3,600 MW and PJM schedules 3,400 MW of power purchases.
1130	VEPCo	200 MW of manually shed load ordered restored.
1144	All PJM utilities	PJM System Operator ordered 500 MW of additional manual load shedding; total is now 1,500 MW.
1200	VEPCo	200 MW of manually shed load ordered restored.
1206	PP&L (PJM)	Martins Creek No. 1 returned to service.
1215	VEPCo	200 MW of manually shed load ordered restored.

Time	System	Event
1215	PennElec (PJM)	Erie Airport removed from manual load drop plans.
1217	APS	The Wylie Ridge-Harrison 500 kV transmission line returned to service (the line had tripped this morning at 0618 hours).
1234	All PJM utilities	The Homer City 345/230-kV "South" autotransformer returned to service. This autotransformer had been in overload condition at 0410 hours this morning.
1254	All PJM utilities	Order for 500 MW of manual load shedding cancelled; total is now 1,000 MW.
1303	All PJM utilities	Order for 500 MW of manual load shedding cancelled; total is now 500 MW.
1307	All PJM utilities	Order for 500 MW of manual load shedding cancelled; there is now no manual load shed remaining.
1327	PP&L (PJM)	Conemaugh No. 2 (850 MW) returned to service.
1330	All PJM utilities	Joint teleconference of Management and Operating Committees to review status of the system.
1423	APS	Harrison-Wylie Ridge 500-kV line returned to service.
1540	All PJM utilities	The 500-kV circuit breaker at Alburtis substation for the 500-kV transmission line to Juniata substation returned to service. This circuit breaker had tripped at 0405 hours this morning.
1551	APS	Kammer-Fort Martin-Harrison 500-kV line trips and recloses only at Kammer. (Kammer is the location with transmission ties to AEP.)
1701	PennElec (PJM)	Sun Pipeline exempted from load curtailment actions.
1845	APS	Notified generating stations to operate such that stack gas emissions level returned to capacity limit.

Time	System	Event
1900	VEPCo	Gravel Neck No. 2 combustion turbine generating unit, 28 MW, returned to service. This unit had tripped at 0400 hours this morning.
1936	All PJM utilities	The System Operator directs that the radio and TV appeals for load curtailment initiated on January 19 be continued on January 20.
2000	All PJM utilities	The System Operator cancels the order that was issued at 0705 to initiate voluntary customer load curtailment.
2000	All PJM utilities	The System Operator cancels the order for member utilities to reduce nonessential building loads.
2028	All PJM utilities	The System Operator cancels the order that was issued at 0645 to initiate 5 percent voltage reduction.
2145	All PJM utilities, VEPCo , APS	Reliability Coordination Plan Step II cancelled.
2200	PennElec (PJM)	Honey Grove circuit supplying Texas Eastern pipeline removed from manual load prop schedule.
2205	PP&L (PJM)	Brunner Island No. 1 (321 MW) returned to service.
2232	All PJM utilities	System Operator cancels the order that was issued at 0600 to initiate load management curtailment steps 1, 2, 3, and 4.
2259	VEPCo	Chesterfield No. 6 steam generating unit, 671 MW, coal-fired, no alternate fuel, out of service because of frozen coal.
2307	All PJM utilities	Emergency generation operations cancelled.
2310	All PJM utilities	Manual load shedding and voltage reduction warnings cancelled.

	Time	System	Event
	2323	All PJM utilities	Following orders cancelled: maximum scheduled generation operations, primary reserve alert and warnings, voltage reduction alert, voluntary customer load curtailment alert.
Thursday, January 20, 1994	0120	Pepco (PJM)	Chalk Point Unit No. 4, 612 MW, tripped because of a fan failure.
	0151	PPL	Susquehanna nuclear Unit No. 2, 1,060 MW, tripped.
	0313	PECO (PJM)	Primary reserve alert and warning issued.
	0405	Pepco (PJM)	Chalk Point Unit No. 4 returned to service.
	0429	VEPCo	Chesterfield No. 6 steam generating unit returned to service. This unit had been taken out of service on Wednesday, January 19, at 2259 hours because of frozen coal.
	0546	VEPCo	Chesterfield No. 6 steam generating unit tripped because of high temperature exhaust steam.
	0600	PECO (PJM)	Issues Cold Weather Alert.
	0606	VEPCo	Chesterfield No. 6 steam generating unit returned to service.
	0757	NYPP	Canceled manual voltage reduction.
	1200	APS, All PJM utilities, VEPCo	Operation of Level 1 of the Reliability Coordination Plan cancelled at direction of APS.
	1200	VEPCo	Gravel Neck No. 1 combustion turbine generator returned to service. This unit had tripped on Wednesday, January 19, at 0600 hours.
	1255	Pepco (PJM)	Order issued to implement the Hot Water Load Management Program from 1530 until 2130.
	1330	All PJM utilities	Joint teleconference of the Management and Operating Committees to review current status of the system.
Friday, January 21, 1994	1155	APS	PJM Primary Reserve Alert and Warning canceled. Severe Alert condition canceled.

D

Power Supply

The Pennsylvania-New Jersey-Maryland (PJM) Interconnection Association and the Virginia Electric and Power control areas within the Eastern Interconnection instituted rolling blackouts during the January 1994 emergency. The PJM control area is also a power pool composed of 10 utilities. These members are:

- Atlantic City Electric Company
- Baltimore Gas and Electric Company
- Delmarva Power and Light Company
- *Jersey Central Power & Light Company
- *Metropolitan Edison Company
- *Pennsylvania Electric Company
- Pennsylvania Power & Light Company
- PECO Energy Company (formerly Philadelphia Electric Co).
- Potomac Electric Power Company
- Public Service Electric and Gas Company

*Subsidiary of the General Public Utilities Corporation

The Mid-Atlantic Area Council (MAAC) is composed of 11 participating companies and eight associate members. The associates are as follows:

- Allegheny Electric Cooperative, representing the Pennsylvania and New Jersey cooperatives
- CRSS Capital, Inc.
- City of Dover, Delaware, representing the Delaware municipals
- City of Vineland New Jersey Electric Utility, representing the New Jersey municipals
- The Easton, Maryland, Utilities Commission, representing the Maryland municipals
- Old Dominion Electric Cooperative (for those cooperatives on the Virginia peninsula)
- Southern Maryland Electric Cooperative (Maryland), representing the Maryland cooperatives
- U.S. Generating Company

Control areas are established for operational reasons to implement the reliability criteria established by power pools and reliability councils. Power pools provide for resource sharing to achieve economic benefits. PJM is the only control area

within MAAC. There are 538 identified generating units in the PJM control center. The electricity supply to an estimated 22 million people in a 50,000-square-mile area of consisting of New Jersey, the District of Columbia, Delaware, and parts of Pennsylvania, Maryland, and Virginia is controlled by PJM.

The 11 member utilities of PJM operate most of the region's powerplants; however, there are 76 other utilities within MAAC. These other utilities are small publicly owned and cooperative systems that purchase most of the power they distribute to their end-user customers from PJM utilities. Some of these small systems have minor amounts of generating capacity. The customer base for MAAC utilities varies from less than 400 customers to almost 2 million. Within PJM, Washington, D.C., and its Maryland suburbs account for between 5 and 6 percent of commercial consumption. The National Capital Region of the General Services Administration manages the electric power supply for Federal facilities. In this area, the Federal loads are estimated to be more than 7 percent of the total electric consumption in the area.

Virginia Power alone serves about 1.8 million customers in Virginia (about 29 percent of the State's population), while North Carolina Power serves 20 counties in North Carolina. The Virginia Electric and Power control area is part of the Virginia-Carolinas (VACAR) subregion of the Southeastern Electric Reliability Council (SERC).

Virginia Power and North Carolina Power are operating entities of the Virginia Electric and Power Company and comprise a single power control area. The Old Dominion Electric Cooperative, several municipal systems, and many NUGs are also within this control area.

Reported System Disturbances in MAAC, 1987-1993

Electric System Disturbances In MAAC Reported To The Department of Energy

Summary 1987 - 1993 By Cause

Cause	Code	1987	1988	1989	1990	1991	1992	1993	Total
Weather	1	2	0	3	0	0	0	6	11
Operation	2	0	0	0	0	0	1	0	1
Demand *	3	1	2	3	1	0	0	0	7
Equipment	4	0	0	3	1	1	1	0	6
Sabotage	5	0	0	0	0	0	0	0	0
Earthquake	6	0	0	0	0	0	0	0	0
Other	7	0	0	0	0	0	0	0	0
Total		3	2	9	2	1	2	6	25

* Demand exceeded the capacity of the generation/transmission system

ELECTRIC POWER SYSTEM DISTURBANCES IN MAAC

REPORTED TO THE DEPARTMENT OF ENERGY

Jan 1, 1987 --- Dec 31, 1987

Date	Time	Area	Utility/Power Pool (Council)	Type of Disturbance	MW Lost	Number of Customers Affected	Restoration Time	Initiating Cause
2/22/87	6:00 AM	Washington, DC & Maryland	Potomac Electric Power Co. (MAAC)	Snow storm 870202	N.A.	110,000	11:00 PM on 2/24/87	1
2/23/87	5:25 AM	Baltimore, MD	Baltimore Gas & Electric Co. (MAAC)	Snow storm 870203	N.A.	250,000	10:00 PM on 2/25/87	1
8/17/87	1:27 PM	PJM Area	PJM Interconnection (MAAC)	5% VR; P.A. 870802	400	3,000,000	5:36 PM Same Day	3

N.A. = Not Available

VR = Voltage Reduction

P.A. = Appeal to the public to reduce use of electricity

870202 Wet and heavy snow accumulated on trees and primary distribution lines. Broken tree limbs falling on distribution circuits interrupted service.

870203 Heavy wet snow caused breakage of tree limbs and distribution lines, and a 13.2 KV transformer failed.

870802 The service area of the Pennsylvania-New Jersey-Maryland interconnection consists of New Jersey, Delaware, the District of Columbia and parts of Pennsylvania, Maryland and Virginia. Details unavailable.

ELECTRIC POWER SYSTEM DISTURBANCES IN MAAC

REPORTED TO THE DEPARTMENT OF ENERGY

Jan 1, 1988 --- Dec 31, 1988

Date	Time	Area	Utility/Power Pool (Council)	Type of Disturbance	MW Lost	Number of Customers Affected	Restoration Time	Initiating Cause
6/22/88	5:10 PM	PJM Area	PJM Interconnection (MAAC)	VR 5% 880603	700	N.A.	8:00 PM Same day	3
8/15/88	1:11 PM	PJM Area	PJM Interconnection (MAAC)	5% VR, P.A. 880808	700	N.A.	5:30 PM Same day	3

N.A. = Information Not Available

VR = Voltage Reduction

P.A. = Appeal to the public to reduce the use of electricity

880603 No details available.

880808 Transmission difficulties interfered with delivery of purchased power from utilities in the ECAR area west of Pennsylvania and the available capacity was insufficient to supply expected demand.

ELECTRIC POWER SYSTEM DISTURBANCES IN MAAC

REPORTED TO THE DEPARTMENT OF ENERGY

Jan 1, 1989 --- Dec 31, 1989

Date	Time	Area	Utility/Power Pool (Council)	Type Of Disturbance	MW Lost	Number of Customers Affected	Restoration Time	Initiating Cause
6/01/89	5:06 PM	Maryland and Washington DC	Potomac Electric Power Co. (MAAC)	Equipment 890601	305	47,500	7:23 PM Same Day	4
6/05/89	12:30 AM	Washington, D.C.	Potomac Electric Power Co. (MAAC)	Cable fire 890603	30 to 35	500	About 8:00AM Next Day	4
6/14/89	3:00 PM	Washington, D.C.	Potomac Electric Power Co. (MAAC)	Storm 890605	700	150,000	About 2 days later	1
6/27/89	1:28 PM	PJM service area	PJM Interconnection (MAAC)	VR 890610	900	N.A.	6:00 PM Same Day	4
7/14/89	2:04 PM	PA/MD/VA	PJM Interconnection (MAAC)	VR 890704	168	1,270,000	7:25 PM Same Day	3
7/26/89	1:54 PM	PJM Area	PJM Interconnection (MAAC)	VR 890708	N.A.	N.A.	6:00 P.M. Same Day	3
11/20/89	11:30PM	Washington, D.C. Area	Potomac Electric Power Co. (PEPCO) (MAAC)	High Winds 891103	N.A.	20,000	Noon 11/21/89	1
11/20/89	9:00PM	Philadelphia, PA Area	Philadelphia Electric Co. (MAAC)	High Winds 891104	N.A.	90,000	Noon 11/21/89	1
12/22/89	7:35AM	Washington, DC	PEPCO & Baltimore G&E Co. (MAAC)	High loads 891210	N.A.	N.A.	11:34AM Same day	3

N.A. = Information Not Available
VR = Voltage Reduction

- 890601 Failure of a secondary bushing on a 69 KV circuit breaker resulted in the destruction of that breaker, a fire, and damage to other facilities in the Bells Mill substation. Five other substations were shut down by protective relaying equipment as a result of the damage to Bells Mill substation.
- 890603 Fire in a manhole on M St. NW damaged 13.2 KV underground cables and spread to other manholes. Commercial and government office buildings in central D.C. lost all power and some 15000 employees were affected. Federal agencies without electricity were: Federal Communications Commission; the Washington office of the U.S. Secret Service; Administrative Council of the United States; Railroad Retirement Board. Traffic signals in the area were inoperable and several streets were closed by police.
- 890605 The most severe storm in PEPCO history broke about 500 distribution lines by knocking down poles and trees, necessitating a massive reconstruction effort.
- 890610 As a result of the loss of a Chalk Point unit on the system of Potomac Electric Power Co. (PEPCO), the entire PJM system had to reduce voltage by 5%. The Potomac Edison Co. (in ECAR) also had to reduce voltage by 5% because it is tied to the PJM system.
- 890704 Lack of sufficient operable generating capacity to meet increasing load necessitated a 5% voltage reduction by Potomac Electric Power Co. and the Baltimore Gas & Electric Co., members of the PJM Interconnection. In order to prevent break-up of the interconnected eastern system, the Allegheny Power System (in ECAR) and Virginia Power Co. (in SERC) also reduced voltage by 5%.
- 890708 Heavy loads and inability to obtain purchased power from systems to the west (ECAR area) made a 5% voltage reduction necessary.
- 891103 A severe windstorm over the mid-Atlantic states caused numerous interruptions of customer service on several systems. Five 69 KV transmission lines on the LILCO system were temporarily put out of service by the winds, as were lines on the PEPCO system at voltage levels of 69 KV, 34 KV and 13KV. No damage to generating plants was reported by any system. In addition to the customer outages listed in the table above, other customer outages (but no details) were reported as follows: Baltimore Gas & Electric Co. 70,000; Pennsylvania Power & Light Co. 113,000; Atlantic City Electric Co. 5,000; Delmarva Power & Light Co. 8,000.
- 891104 A severe windstorm over the mid-Atlantic states caused numerous interruptions of customer service on several systems. Five 69 KV transmission lines on the LILCO system were temporarily put out of service by the winds, as were lines on the PEPCO system at voltage levels of 69 KV, 34 KV and 13KV. No damage to generating plants was reported by any system. In addition to the customer outages listed in the table above, other customer outages (but no details) were reported as follows: Baltimore Gas & Electric Co. 70,000; Pennsylvania Power & Light Co. 113,000; Atlantic City Electric Co. 5,000; Delmarva Power & Light Co. 8,000.
- 891210 On Dec 22 Potomac Electric Power Co. (PEPCO) and Baltimore Gas & Electric Co. (BGE) instituted a 5% voltage reduction between 7:35AM and 11:34 AM because cold weather caused unexpectedly high loads and problems in the delivery of No. 6 fuel oil required system operation such that fuel oil would be conserved.

ELECTRIC POWER SYSTEM DISTURBANCES IN MAAC

REPORTED TO THE DEPARTMENT OF ENERGY

Jan 1, 1990 --- Dec 31, 1990

Date	Time	Area	Utility/Power Pool (Council)	Type of Disturbance	MW Lost	Number of Customers Affected	Restoration Time	Initiating Cause
7/03/90	1:45 PM	Baltimore- Washington	PJM Interconnection (MAAC)	VR, P.A. 900703	770	N.A.	4:45 PM Same day	3
7/28/90	1:04 PM	Baltimore, MD	Baltimore Gas & Electric Co. (MAAC)	Equipment 900707	430	93,925	1:07 PM Same Day	4

N.A. = Not Available

VR = Voltage Reduction

P.A. = Appeal to the public to reduce the use of electricity

900703 High temperatures and high humidity in the Baltimore-Washington area caused loads to approach projected summer peak values. Power imports from the ECAR area were near critical levels, beyond which system voltage collapse was possible, and several generating units tripped. As a result, during the afternoon, Potomac Electric Power Co. and Baltimore Gas & Electric Co. reduced voltage by 5%, then issued public appeals for energy conservation and ultimately went to rotating load shedding. Each system shed about 200 MW. The voltage reductions reduced load by about 300 MW; the public appeals combined with requests to large customers for voluntary load reduction, reduced load by 70 MW, and the load shedding gained 400 MW additional.

900707 A 230 KV/115 KV transformer at Waugh Chapel Substation failed due to an internal fault. Personnel working on another transformer in the substation were able to expedite transfer of load from the faulted transformer to the transformer on which they had been working.

ELECTRIC POWER SYSTEM DISTURBANCES IN MAAC

REPORTED TO THE DEPARTMENT OF ENERGY

Jan 1, 1991 --- Dec 31, 1991

Date	Time	Area	Utility/Power Pool (Council)	Type of Disturbance	MW Lost	Number of Customers Affected	Restoration Time	Initiating Cause
11/09/91	11:40AM	Salem County N.J.	PJM Interconnection (MAAC)	Equipment 911101	None	None	Not Applicable	4

911101 A fire and explosion followed by a reactor trip occurred at the Salem No.2 nuclear generating unit when blading of the low pressure turbine was thrown through the casing, possibly because of turbine overspeed. The fire lasted about 15 minutes, involving turbine-generator lubricating oil and the hydrogen used for cooling the generator. Preliminary reports state that the incident followed testing of the turbine overspeed trip mechanism. Customers of the utilities in the PJM Interconnection were not affected.

ELECTRIC POWER SYSTEM DISTURBANCES IN MAAC

REPORTED TO THE DEPARTMENT OF ENERGY

Jan 1, 1992 --- Dec 31, 1992

Date	Time	Area	Utility/Power Pool (Council)	Type of Disturbance	MW Lost	Number of Customers Affected	Restoration Time	Initiating Cause
1/06/92	5:04 PM	Washington, DC Downtown area	Potomac Electric Power Co. (MAAC)	Equipment 920101	300	18,000	7:43 PM Same day	4
12/16/92	4:47 AM	Southern MD	Southern Maryland Elec. Coop. (MAAC)	Misoperate 921204	85	41,000	6:02 AM Same day	2

920101 During a normal switching operation, the switching device malfunctioned, initiating an arc between two 230 KV cables that connect PEPCO's Station C to the system. The station was thereby disconnected from the system, and its five generating units tripped, causing loss of all load supplied from that station. An emergency tie with Virginia Electric & Power Co. was established to allow service restoration to begin.

921204 While one of two 69 KV lines supplying power to the cooperative was being switched, improper operation of a protective relay caused the other line to trip, cutting off service to the cooperative. The relaying arrangements have been corrected.

ELECTRIC POWER SYSTEM DISTURBANCES IN MAAC

REPORTED TO THE DEPARTMENT OF ENERGY

Jan 1, 1993 --- Dec 31, 1993

March was the only month for which disturbances were reported in 1993

Electric System Disturbances In MAAC Reported to The Department of Energy For March 1993

Date	Time	Area	Utility/Power Pool (Council)	Type Of Disturbance	MW Lost	Number of Customers Affected	Restoration Time	Initiating Cause
3/13/93	2:53 AM	Delmarva Peninsula	Delmarva Power & Light Co. (MAAC)	Storm 930308	N.A.	20,000	4:14 PM 3/14/93	1
3/13/93	N.A.	Baltimore & N.E. MD	Baltimore Gas & Electric Co. (MAAC)	Storm 930313	N.A.	132,000	Midnight 3/14/93	1
3/13/93	N.A.	Washington D.C. & S. MD	Potomac Electric Power Co. (MAAC)	Storm 930314	N.A.	6,500	N.A. 3/14/93	1
3/13/93	N.A.	Atlantic City NJ	Atlantic Electric Co. (MAAC)	Storm 930316	N.A.	25,000	Evening 3/14/93	1
3/13/93	7:00 AM	New Jersey	Public Service Elect. & Gas Co. (MAAC)	Storm 930318	N.A.	26,000	Noon 3/14/93	1
3/13/93	Mid-day	East Central NJ	Jersey Central Power & Light Co. (MAAC)	Storm 930319	N.A.	74,000	6:00 PM 3/14/93	1
3/13/93	6:00 AM	Philadelphia PA & suburbs	Philadelphia Electric Co. (MAAC)	Storm 930320	N.A.	100,000	Evening 3/14/93	1

N.A. = Not Available

930308 A storm tripped a 69 KV line and affected numerous distribution circuits. At the Indian River Power Plant a temporary operating problem occurred when high winds blew water out of the cooling water intake.

930309 Customer outages were due to storm effects on distribution circuits. The transmission system, and generating plants, were not affected.

930313 Storm damage to distribution facilities interrupted service to some customers but transmission facilities were not affected. Crane Generating Plant tripped when a static wire failed; the Plant was restored to service without difficulty.

930318 Distribution circuits tripped, interrupting customers. There were no problems with generation or transmission.

930319 The service interruptions were caused by breakage of 35 distribution poles, 315 wire sections down, 2 circuit breaker trips and outage of 38 distribution circuits.

930320 One transmission substation tripped when hit by lightning but was restored to service. Generating plants were not affected. Customer outages were caused by distribution circuit damage.

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14. Interview with Energy Office and Public Utilities Commission Staff for District of Columbia.
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17. Responses of Allegheny Power System, Virginia Power, the PJM Interconnection, the Pennsylvania Power and Light Company, PECO Energy, Inc., the Virginia Power Company, the Public Service Electric and Gas Company, the Baltimore Gas and Electric Company, the Potomac Electric Power Company, and Baltimore Gas and Electric Company to questionnaires sent by the Department of Energy.
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20. Pennsylvania Public Utility Commission staff report.
21. Virginia State Corporation Commission staff report, "Virginia Electric and Power Company's January 19, 1994, Rotating Blackouts," September 27, 1994.

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