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TECHNOLOGY CHOICE IN A LEAST-COST EXPANSION ANALYSIS FRAMEWORK: IMPLICATIONS FOR STATE REGULATORS

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by

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TECHNOLOGY CHOICE IN A LEAST-COST EXPANSION ANALYSIS FRAMEWORK: IMPLICATIONS FOR STATE REGULATORS

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Abstract

It is inevitable that new power plants will need to be constructed in the near future; however, it is unclear which technologies will be selected for these new plants. In a study for the U.S. Department of Energy, the impacts of fuel prices, length of the planning period, and the characteristics of the generating system were examined for their influence on technology choice in 10 representative power pools. It was determined that natural gas combined-cycle technology was generally preferred for base-load and intermediate/cycling capacity when gas prices are low and the planning period is short (10 years). Integrated coal gasification combined-cycle plants were selected to serve most base-load requirements under other conditions. One aspect often overlooked in making a least-cost technology choice is system reliability: nonoptimal technology choices can be made if alternative expansion plans do not have the same level of reliability when discounted system costs are compared.

1.0 Introduction

The current outlook for new capacity additions by electric utilities is uncertain and tenuous. One reason is that utilities have become capital averse due to a multitude of regulatory, market, and supply issues. To avert some of these problems, utilities are looking favorably at natural gas technologies, since they offer rapid construction/deployment, low capital investment, and higher availability than coal-fired technologies. This situation has implications for the reliability of the generating system.

Of concern to state regulators is how to evaluate a least-cost plan. A least-cost plan has many components. To understand the results, one must review the input data and assumptions. A single least-cost plan is difficult to analyze without reviewing several parallel studies in which key input parameters have been changed. The changes in the

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least-cost plan indicate how stable the solution is in response to fluctuations in key parameters.

In this study, key parameters to study were selected based on the following questions: 1) What is the impact of alternative gas projections on technology choice? 2) What influence does the planning horizon (10 versus 30 years) have on technology choice? 3) How important are existing system characteristics (e.g., mix of technologies, operating costs, load shape) on technology choice?

In a study for the U.S. Department of Energy, Office of Fossil Energy (DOE/FE), we examined the impact of these concerns on technology choices in 10 representative power pools with a dynamic optimization expansion model, the Wien Automatic System Planning (WASP) Package.[1] These 10 power pools were determined to be representative on the basis of a cluster analysis conducted on all 26 power pools in the United States (see Fig. 1). A least-cost expansion plan was determined for each power pool with three candidate technologies--natural gas combustion turbine (GT), natural gas combined cycle (NGCC), and integrated gasification combined cycle (IGCC)--three alternative gas price tracks, and two planning horizons between the years 1995 and 2020. This paper summarizes the analysis framework and presents results for two power pools: Power Pool 1, the American Electric Power (AEP) service territory, and Power Pool 16, composed of all the utilities in the state of Florida.

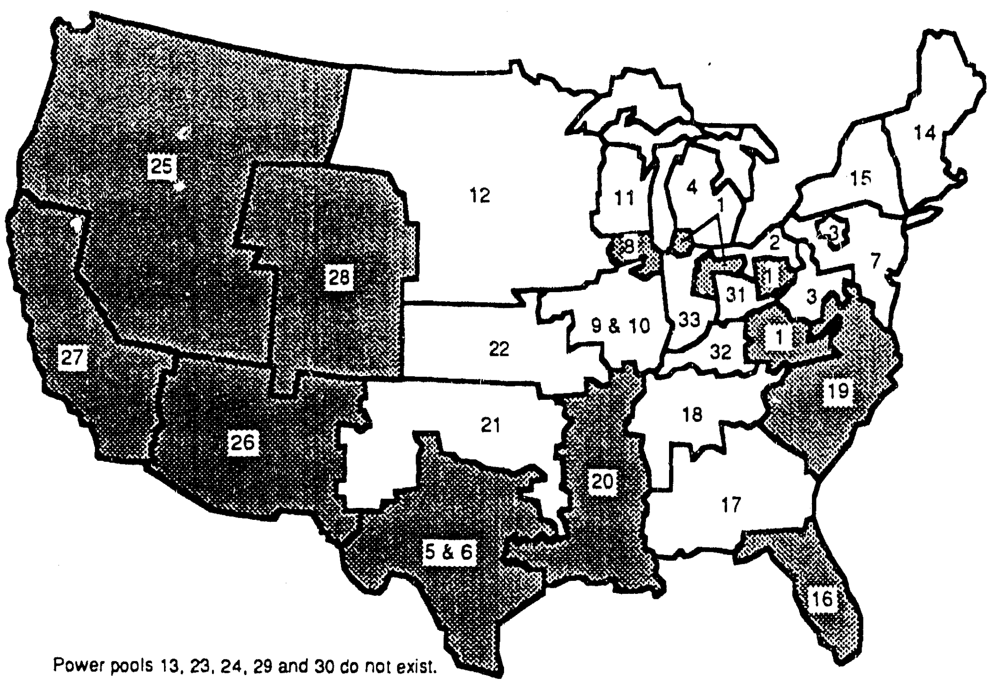


Figure 1. Power Pools (Highlighted Pools Indicate Those Examined in Study)

2.0 Analysis Framework

2.1 Methodology

The WASP Package uses dynamic programming to develop a least-cost optimization plan for a period of up to 30 years, on the basis of user-supplied constraints such as the cost of unserved energy, reserve margin limits, and a loss-of-load probability (LOLP). In WASP, the optimal solution is the minimum discounted system costs over the study period. The system costs include the capital investment for new units, the salvage value associated with new units, fuel costs, operation and maintenance (O&M) costs, and the cost of energy not served. WASP evaluates these components in terms of their net present value to compare the cost of alternative system expansion plans. The model uses probabilistic simulation to calculate the system production costs and reliability level.[2,3]

2.2 Model Constraints

Constraints were imposed to bound the simulation problem and ensure a realistic solution. The reserve margin for each pool was constrained to be between 15% and 25%. The level of reserve margin maintained within a pool is determined by the model in conjunction with the amount and cost of unserved energy. No LOLP constraint was imposed (although it was examined in each simulation for reasonableness). WASP calculates the financial tradeoff between building new generating units or paying a cost for each kilowatt-hour (kWh) of unserved energy. Unserved energy was assigned a cost of $0.10/kWh. There were no constraints imposed on the number of new units that could be added in any year. In addition, each new technology was considered to be available and fully functional starting January 1, 1995.

2.3 Input Data Sources

The data requirements for WASP fall into two basic categories, load data and unit data.

Load Data. The load data requirements are seasonal load duration curves and seasonal and annual peak loads. The annual peak loads for each pool were selected from the 1988 regional North Electric Reliability Council reports for the years 1995-1997. The annual peak loads beyond 1997 were assumed to increase at 1.9% per year in each pool until the end of the study based on a national electricity demand forecast.[4]

Unit Data. The unit data requirement include operating characteristics for all units in the current operating system, together with any planned additions and retirements. For each plant or unit, the following data were required: capacity, heat rate, fuel cost, forced outage rate, scheduled maintenance, spinning reserve, fixed O&M, and variable O&M. Data for existing units were extracted from the Argonne Power Plant Inventory (APPI).

Detailed operational and economic data are also required for new units. The characteristics of new units included in the build slate of the model are listed in Table 1. As seen in Table 1, the maximum availability for the NGCC unit is 10 percentage points higher than the IGCC unit.

Table 1. Characteristics of New Units

Characteristic	ICCC	NCCC	Gas Turbine
Size (MWe)	420	420	150
Annual Average Heat Rate (Btu/kWh)	8750	7800	12900
Forced Outage Rate (%)	14.4	2.5	4.3
Scheduled Maintenance (days)	14	20	18
Maximum Availability (%)	82	92	91
Variable O&M* (mills/kWh)	2.0	1.0	4.6
Fixed O&M* ($/kW-yr)	27.0	6.84	0.5
Capital Cost* ($/kW)	1150	485	265
Construction Time (yr)	4	3	1
Lifetime (yr)	30	30	30

*All costs are in 1985 dollars.

Source: Ref. 5.

2.4 Scenario Definitions

To understand how and when new coal-fired and gas-fired technologies would be competitive, three fuel price tracks and two planning periods were studied. The three gas price tracks examined were low (Data Resources Inc. [DRI] 1990 gas price projection escalated at 2% per annum), medium,[6] and high.[7] The 2% and DRI fuel price tracks were run for all power pools. The Gas Research Institute (GRI) fuel price track was run for only selected power pools.

Two planning periods were examined--a short-term outlook of 10 years and a conventional outlook of 30 years--to represent alternative utility philosophies toward capital investment and regulatory risk. The intent of the two planning periods was to address the question, "Does the length of the planning period affect technology choice?"

3.0 Power Pool Summary Results

This section summarizes the results for Power Pools 1 and 16 to illustrate the effects of different gas price tracks, planning horizons, and system characteristics on technology choice. Power Pool 1 represents the American Electric Power (AEP) System, Buckeye Power Inc., Ohio Valley Electric Corp., and Richland Power and Light utilities. Power Pool 16 represents the utilities in the Florida Subregion of the Southeast Electric Reliability Council (SERC).

The scenarios for each power pool are referred to as 2%, DRI, or GRI; a "/10" or "/30" following the fuel price nomenclature indicates the planning period. The discussion also refers to base-load, intermediate cycling, and peaking capacity. Base-load capacity is assumed to run at an annual capacity factor greater than 50%. Intermediate cycling capacity runs at an annual average capacity factor of between 20-50%, and peaking capacity is considered to run at an annual average capacity factor less than 20%.

3.1 Power Pool 1

In 1987, the utilities that make up Power Pool 1 had approximately 26.1 GW of capacity; greater than 88% of this capacity was coal-fired (see Fig. 2). This capacity served an annual peak load of 18.0 GW (1987). Most of the excess capacity reflects firm base-load electricity sales to contiguous power pools and not an excessively high reserve margin. Total generation was principally supplied by coal-fired capacity (89%). Less than 1% of capacity and generation in 1987 was oil- and gas-fired.

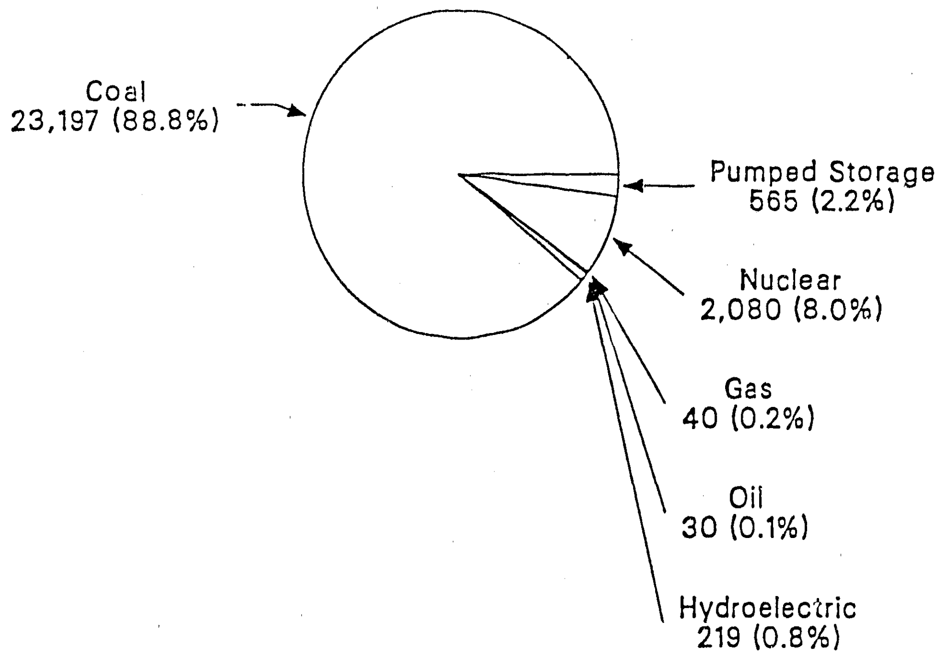


Figure 2. 1987 Capacity in Power Pool 1 (MW)

Overview of Optimization Results. No NGCC units were selected to provide new baseload capacity in any of the gas price track/planning horizon scenarios in Power Pool 1. The new capacity requirements were met by NGCC units operating as intermediate/peaking capacity in the 2%/10, 2%/30, and DRI/10 scenarios and by base-load IGCC units in the DRI/30, GRI/10, and GRI/30 scenarios. The operation of the existing coal-fired capacity in Power Pool 1 is dictated by the new technology chosen: When NGCC is selected, the existing coal units operate as base-load units; when IGCC is chosen, the existing coal units function as intermediate/peaking capacity.

When the levelized gas price rises by $\$1.29/10^6$ Btu (i.e., from the DRI/10 to GRI/10 scenario), WASP alters its technology choice and also alters where the selected technology operates in the loading order; for example, NGCC is selected to serve the intermediate/peaking function in DRI/10, whereas in GRI/10, IGCC base-load technology is preferred (see Fig. 3).

In the 2%/30 scenario, NGCC units are used only as intermediate/peaking capacity (see Fig. 4). When the levelized gas price increases by $\$1.13/10^6$ Btu (i.e., from the 2%/30 to the DRI/30 scenario), NGCC units are not selected to serve any type of load. Due to higher gas prices, IGCC units are built to function as base-load capacity

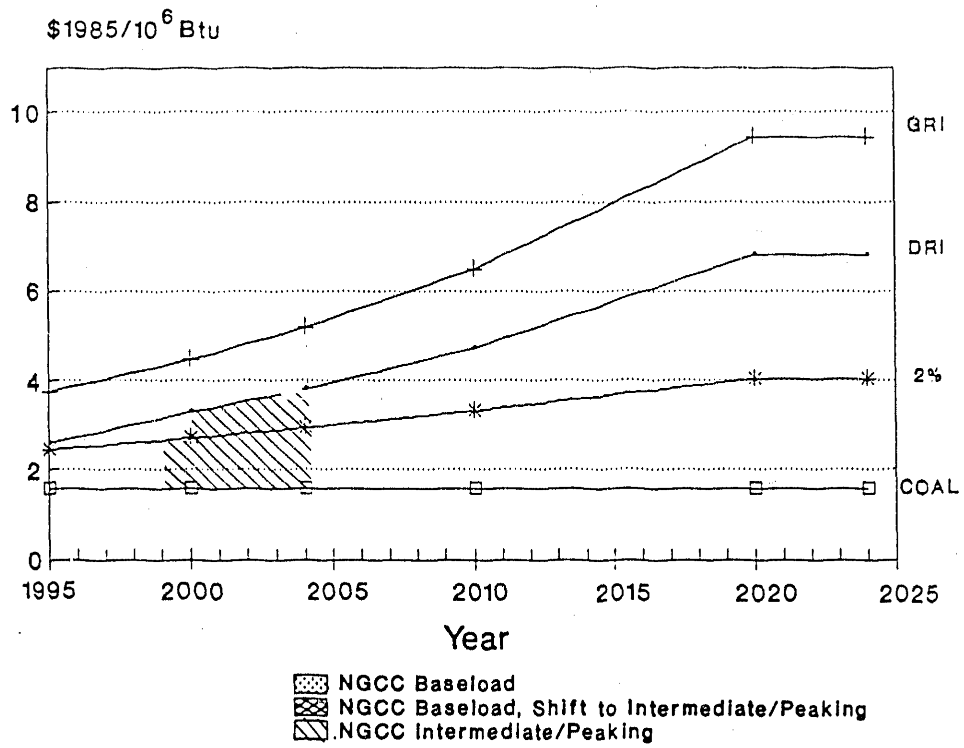


Figure 3. Power Pool 1: Dispatch of NGCC Technology Selected by Gas Price Track (10-Yr Planning Period)

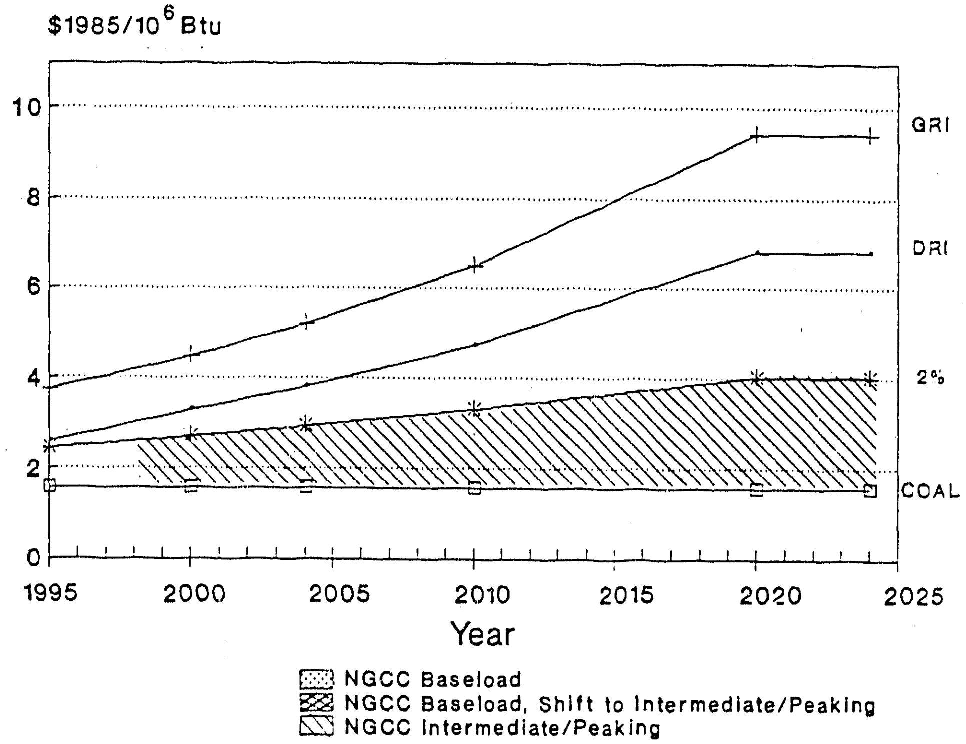


Figure 4. Power Pool 1: Dispatch of NGCC Technology Selected by Gas Price Track (30-Yr Planning Period)

throughout the 30-year planning periods, which implies that existing coal units are used for intermediate/peaking capacity.

Figure 5 depicts the amount and type of technology selected by gas price track and planning horizon in the 1995-2004 time period. The impact of technology choice on unserved energy can be seen in Fig. 6. The GRI/10 and GRI/30 scenarios, which build predominantly IGCC units during the 1995-2004 time period have 30-100% more unserved energy than the scenarios where NGCC units are added.

Although the DRI/30 and 2%/30 scenarios both add 2940 MWe of non-peaking capacity, the DRI/30 scenario has 1278 GWh (30%) more unserved energy during the period 1995-2004. This energy could be provided by a 145 MWe unit with 100% availability. The increase in unserved energy is the result of a delayed construction schedule and different operating availabilities between the IGCC and NGCC units. These scenarios have the same amount of unserved energy from 1995-1997.

Even though the first NGCC unit in the 2%/30 scenario was added two years earlier than the first IGCC unit in the DRI/30 scenario, the DRI/30 scenario had 30-99% more unserved energy in each year from 1998-2004. This difference is maintained throughout the study period. The cumulative unserved energy through 2024 is 3983 GWh, or 39%, higher in the DRI/30 scenario than the 2%/30 scenario. The system reliability in the DRI/30 scenario is lower, even though the discounted costs were $734 million (1.2%) higher as compared with the 2%/30 scenario. This implies an increased probability for a system failure. If these scenarios were constrained to maintain the same LOLP, the costs would be higher and there could be an impact on technology choice, but the results from a reliability viewpoint would be more comparable.

Impact of Planning Horizon, 1995-2004. Within the 1995-2004 time period, the amount of new capacity added varies by length of the planning period, gas price track, and technology selected. Depending on the gas price track, 4350 to 4770 MWe are added in the 10-year planning period, and 4830 to 5040 MW are added in the 30-year planning period (see Fig. 5). More capacity is built between 1995 and 2004 under the 30-year planning periods due to the long-run benefits of such capacity additions, which are not captured in the 10-year planning period. The reduction in capacity varies from 270 MWe under the 2% gas price track to 690 MWe under the DRI gas price track. This reduction in capacity is reflected in an increase in unserved energy (see Fig. 6). Although the DRI scenario has the largest difference in new capacity, it has the smallest difference in unserved energy. This is because of the change in technology selected.

As indicated in Fig. 5, there is no clear technology choice within each planning period; instead, technology choice appears to be more a function of gas price. For example, in the 2%/30 and DRI/30 scenarios, the amount of capacity additions between

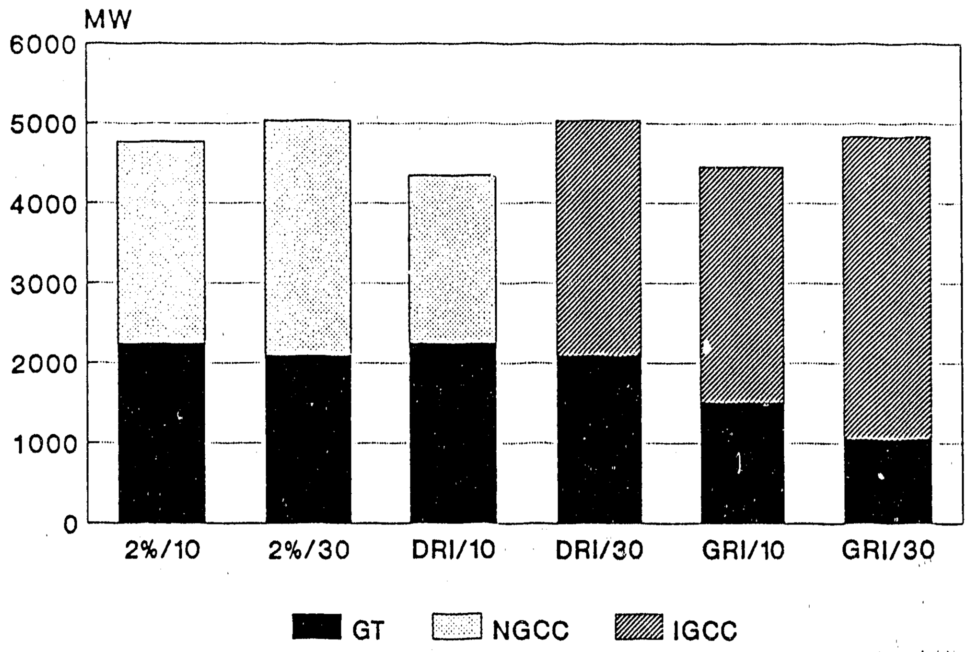


Figure 5. Power Pool 1: Cumulative Capacity Additions
by Technology and Scenario, 1995-2004

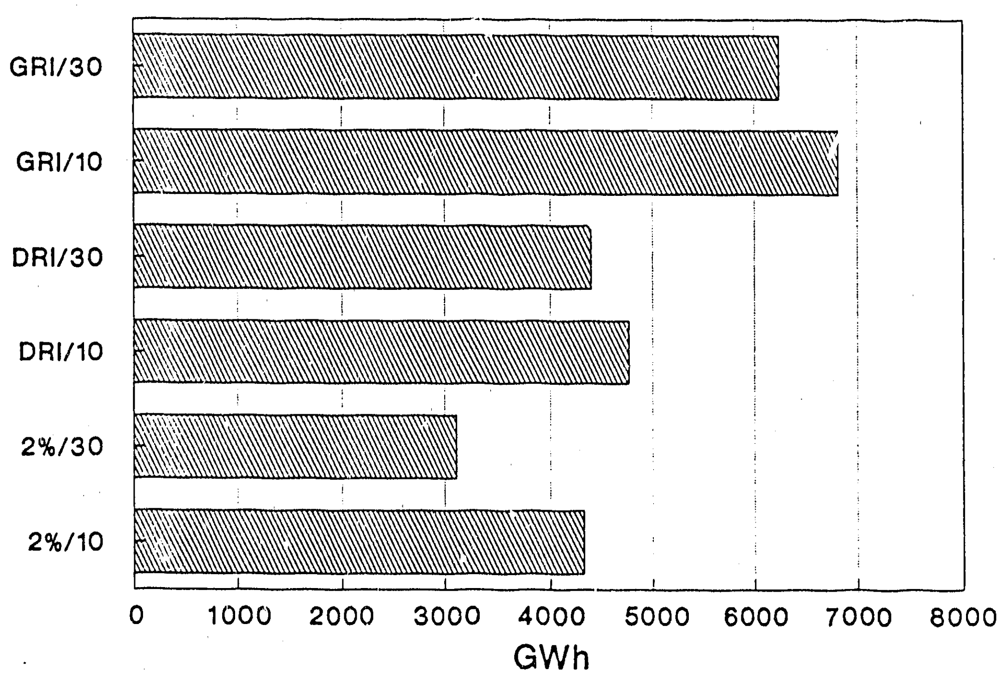


Figure 6. Power Pool 1: Cumulative Unserved Energy
by Scenario, 1995-2004

1995 and 2004 is identical, but NGCC is replaced with IGCC technology (see Fig. 5). Although this switch in technologies does not affect the amount of capacity added, unserved energy increases by 41% in the DRI/30 scenario (see Fig. 6). In the GRI/30 scenario, the amount of IGCC capacity in the system increases, reducing GT additions relative to those of the DRI/30 scenario. Given the additional IGCC capacity in the system, the unserved energy relative to that of the DRI/30 scenario increases by 30%, because the number of GT units is reduced to compensate for the $\$1.67/10^6$ Btu increase in levelized gas price that occurs when going from the DRI/30 to the GRI/30 scenario.

Impact of Gas Price Track

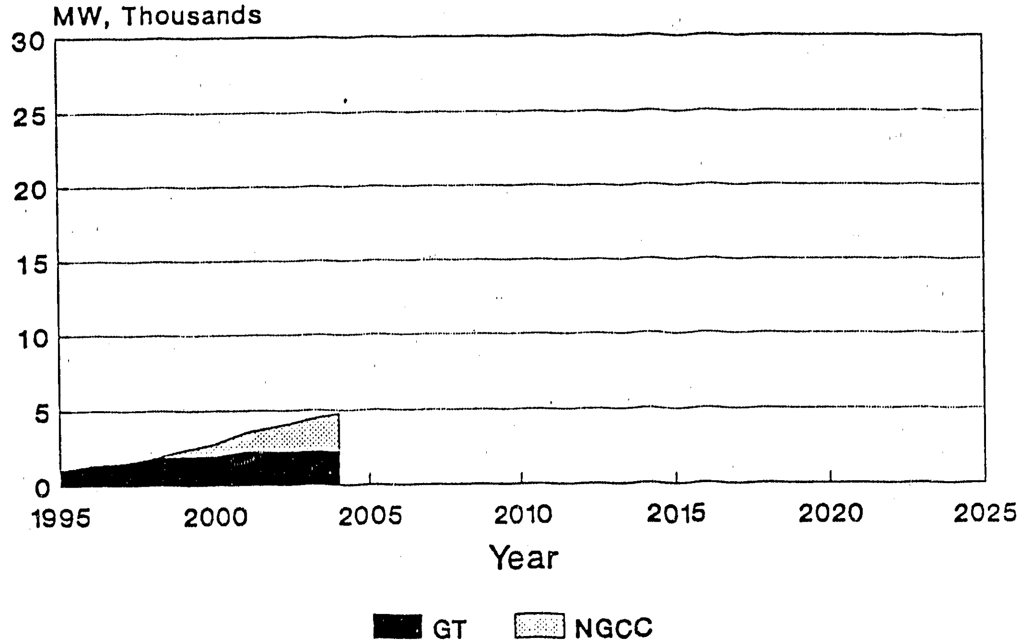
2% Gas Price Track: New NGCC units are added for intermediate cycling capacity in both the 10-year and 30-year planning periods. Figure 7 portrays the build schedule for new capacity additions in both periods. In the 30-year period, the construction schedule for NGCC units is advanced from the 1998-2004 period; such a shift results in a 20% (791 GWh) decrease in the amount of unserved energy during this period as compared with that of the 10-year planning period (see Fig. 6).

The $\$0.40/10^6$ Btu increase in the levelized gas price that occurs in going from the 2%/10 to the 2%/30 scenario causes the last NGCC unit to be added in 2006 (in the 2%/30 scenario). After the last NGCC unit is added, IGCC units provide the majority of the new capacity additions, with only four GT units being added from 2006-2024.

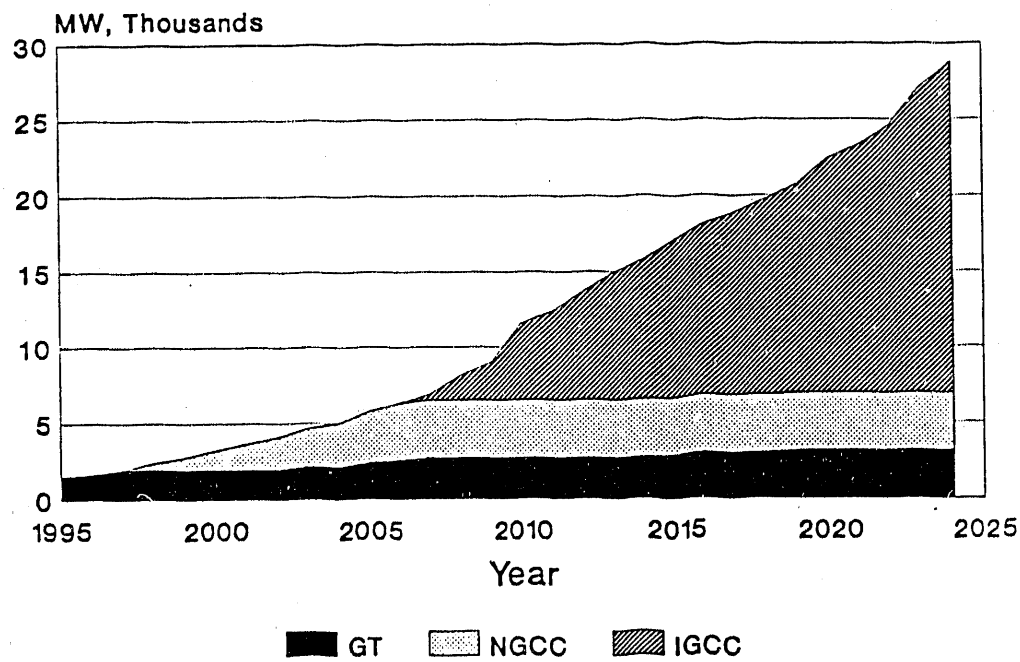
DRI Gas Price Track: In the DRI gas price track, WASP changes the type of new technology added as well as its function (base-load versus intermediate cycling) when shifting from the 10-year to the 30-year planning period. Figure 8 indicates the build schedule for the 10-year and 30-year planning periods.

The $\$0.49/10^6$ Btu increase in the levelized gas price that occurs in going from the 2%/10 to the DRI/10 scenario results in 420 MWe less capacity in the DRI/10 scenario. The difference in capacity constructed is reflected in the amount of unserved energy corresponding to each scenario: DRI/10 has 10.3% more unserved energy than the 2%/10 scenario (see Fig. 6).

In the 30-year planning period, WASP selects IGCC units to meet base-load capacity, while existing units are used for intermediate cycling capacity. Conversely, in the 10-year planning period, NGCC units are selected by WASP to meet intermediate cycling capacity, while the existing coal units continue to function as base-load capacity. Technology choice is altered when levelized gas prices increase by approximately $\$1.00/10^6$ Btu when going from the DRI/10 to the DRI/30 scenario.

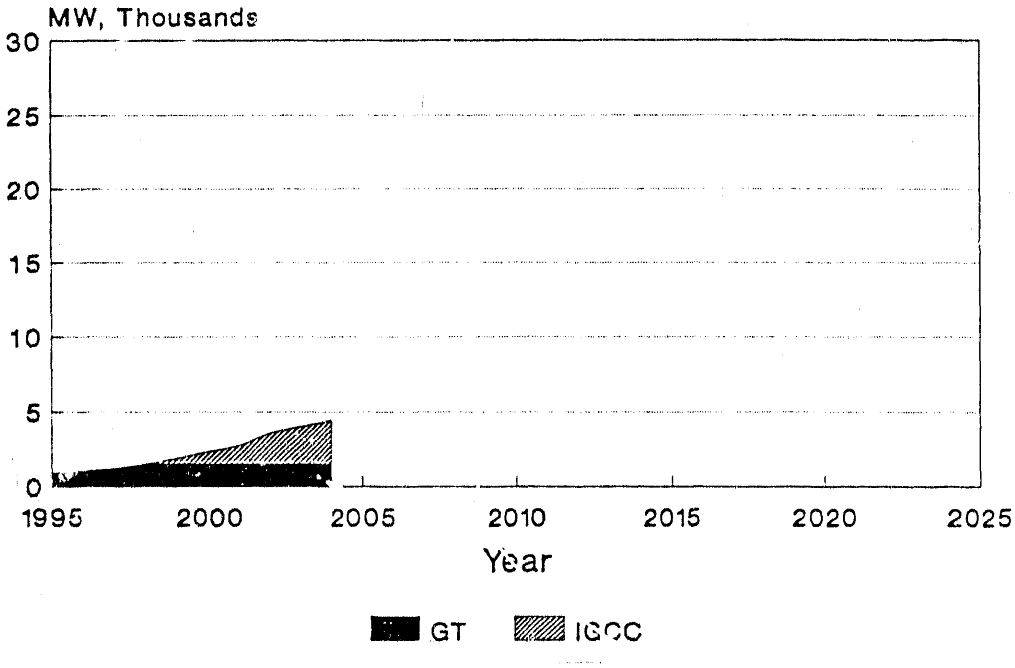


a. 10 Year Optimization

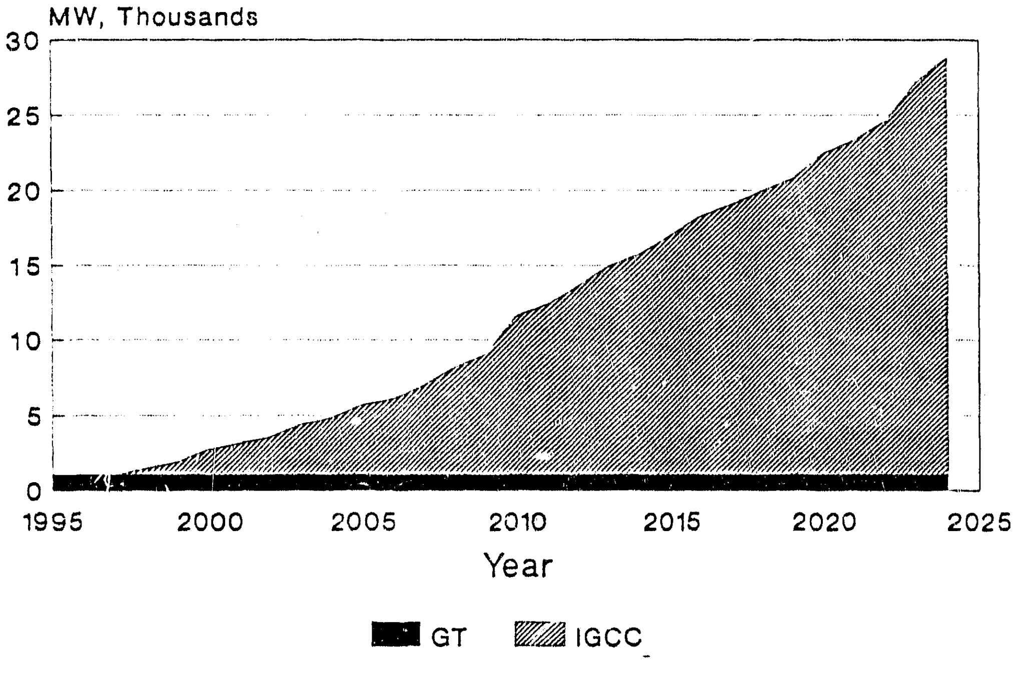


b. 30 Year Optimization

Figure 7. Power Pool 1: Cumulative Capacity Additions by Technology for 10-Yr and 30-Yr Planning Horizons: 2% Gas Price Track



a. 10 Year Optimization



b. 30 Year Optimization

Figure 8. Power Pool 1: Cumulative Capacity Additions by Technology
10-Yr and 30-Yr Planning Horizons: DRI Gas Price Track

The cost of running NGCC units as the gas price continues to escalate makes them uneconomical, even between 1995 and 2004, because of the need to continue operating these units throughout their economic life. IGCC units are preferred in the 30-year analysis because future fuel savings offset the high capital investment required by the units. The existing units in the pool can be operated as intermediate/peaking capacity, while the new IGCC units operate as base-load capacity.

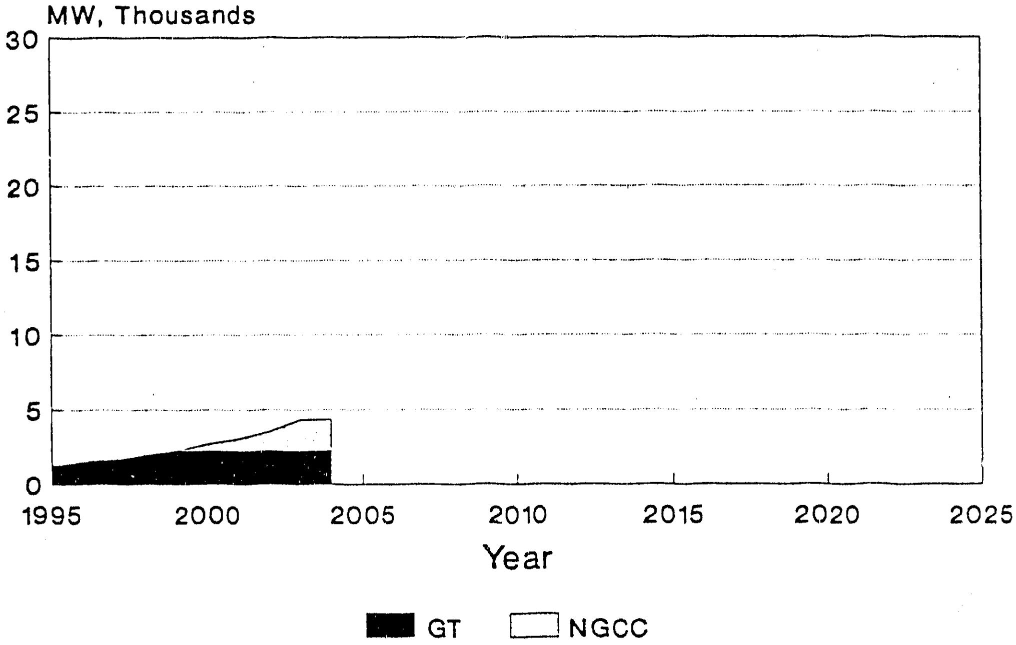
GRI Gas Price Track: Figure 9 depicts the build schedule for new units in the 10-year and 30-year planning periods. In both periods, IGCC units are added to meet new base-load capacity requirements. This result follows from the DRI gas price track, in which NGCC units functioned only as intermediate cycling capacity in the 10-year planning period.

In the GRI/10 scenario, 100 MWe more capacity are added by 2004 than in the DRI/10 scenario. With the increase in levelized gas price of $1.29/10^6 Btu that occurs in going from the DRI/10 to the GRI/10 scenario, the GRI/10 scenario selects IGCC capacity, while the DRI/10 scenario selects NGCC units. As a result of the differences in equivalent availability between NGCC and IGCC technologies, the amount of unserved energy increases by 43% in going from the DRI/10 to the GRI/10 scenario (see Fig. 6).

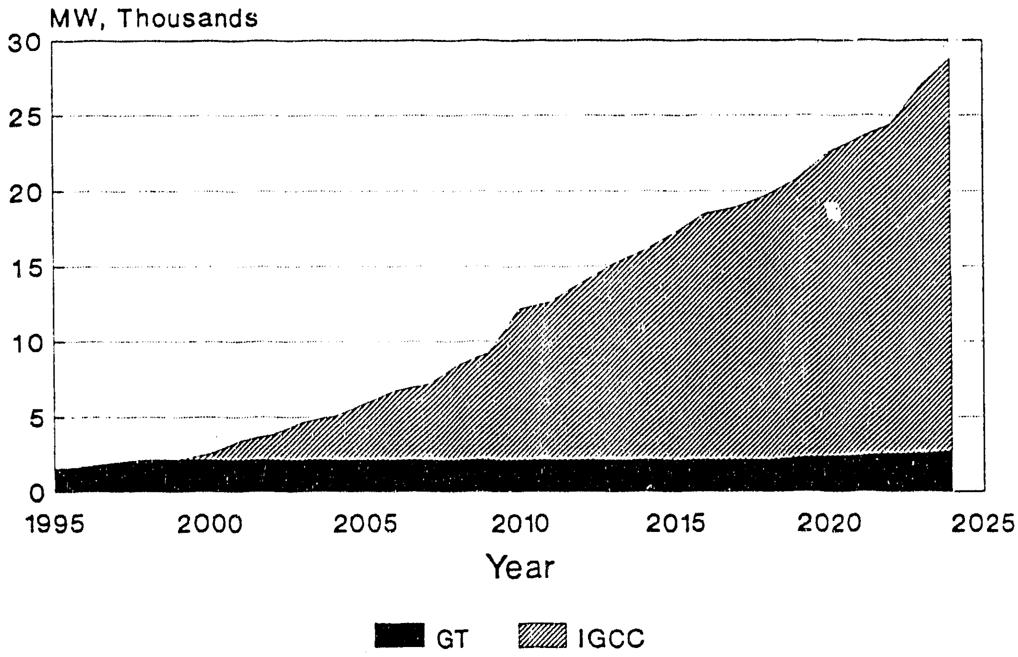
The build schedule for IGCC units within the 1998-2004 period was advanced in the GRI/30 scenario relative to the GRI/10 scenario. In 2004, the 10-year planning period has two less IGCC units and three more GT units, which translates into 390 MWe less capacity than that in the 30-year planning period. As a result, the 10-year planning period has 578 GWh, or 9%, more unserved energy compared with the 30-year planning period. In the 30-year planning period after 2004, only IGCC units are added through the end of the planning period.

3.2 Power Pool 16

Power Pool 16 represents most of the utilities in the state of Florida; the pool had 29.6 GW of capacity and 24.3 GW of peak load in 1987 (see Fig. 10). Although there appears to be an adequate reserve margin, Power Pool 16 imported 17.7 GWh of electricity in 1987. Oil units represented the largest share of capacity in 1987 (40.0%), yet they provided only 18.5% of the nominal generation used within Power Pool 16. Because oil units are expensive to operate, Power Pool 16 elected to import power from utilities outside the pool at a lower price than the cost that they would have incurred if they generated the electricity from their own oil units. Even with coal and nuclear units generating over 50% of the nominal energy in 1987, Power Pool 16 still had to generate 32% of its energy from the more expensive oil and gas units.



a. 10 Year Optimization



b. 30 Year Optimization

Figure 9. Power Pool 1: Cumulative Capacity Additions by Technology for 10-Yr and 30-Yr Planning Horizons: GRI Gas Price Track

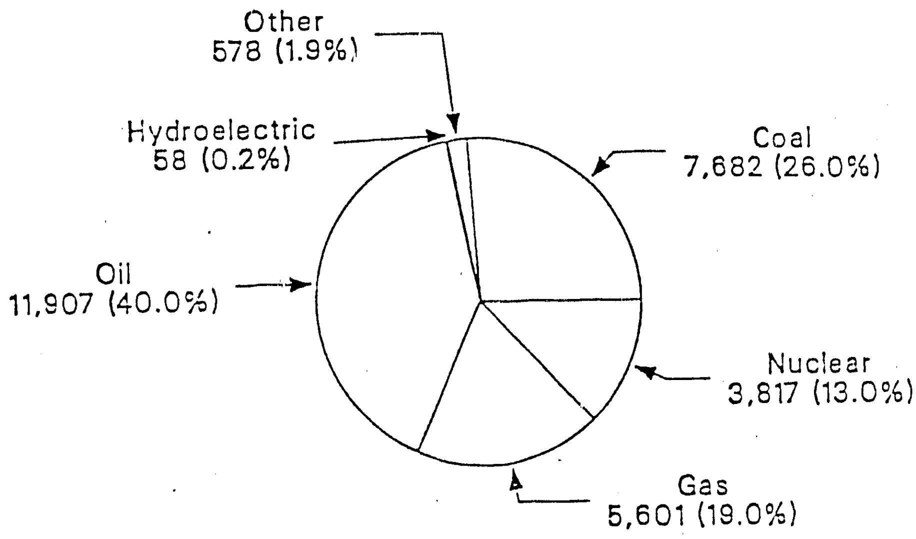


Figure 10. 1987 Capacity in Power Pool 16 (MWe)

Overview of Optimization Results. As illustrated in Figs. 11 and 12, NGCC units were selected to provide new base-load capacity in all scenarios between the years 1995-2004, because they are more economical to operate than existing plants. In the DRI/30, GRI/10, and GRI/30 scenarios, new IGCC units were added in addition to the NGCC units between 1995 and 2004. The high capacity factor of the new NGCC units, even when IGCC units are added, indicates that the older oil and gas units are being displaced by the more efficient NGCC units.

Figure 13 shows that the amount of new capacity additions from 1995-2004 are almost identical in all scenarios. However, the amount of unserved energy in the GRI scenarios is over 500% higher when compared with the 2% and DRI scenarios (see Fig. 14). The 2% and DRI scenarios have greater than 50% new NGCC capacity; compared with the GRI scenarios which have greater than 50% new IGCC capacity, these scenarios have only a marginal amount of unserved energy. The GRI scenarios have 380-424 GWh more unserved energy than the other scenarios. This unserved energy could be met by a 43-50 MWe unit with a 100% reliability.

The GRI/30 scenario, as compared with the DRI/30 scenario, has 420-1680 MWe less new capacity in each year from 1995-2001. The capacity delay is partially due to the increased gas price track. By 2024, the DRI/30 and GRI/30 scenario add the same amount of new capacity; however, the cumulative unserved energy is still over 600% higher in the GRI/30 scenario (129 versus 873 GWh). The delays in the addition of new capacity in the early part of the GRI/30 scenario results in a less reliable system over the entire study period.

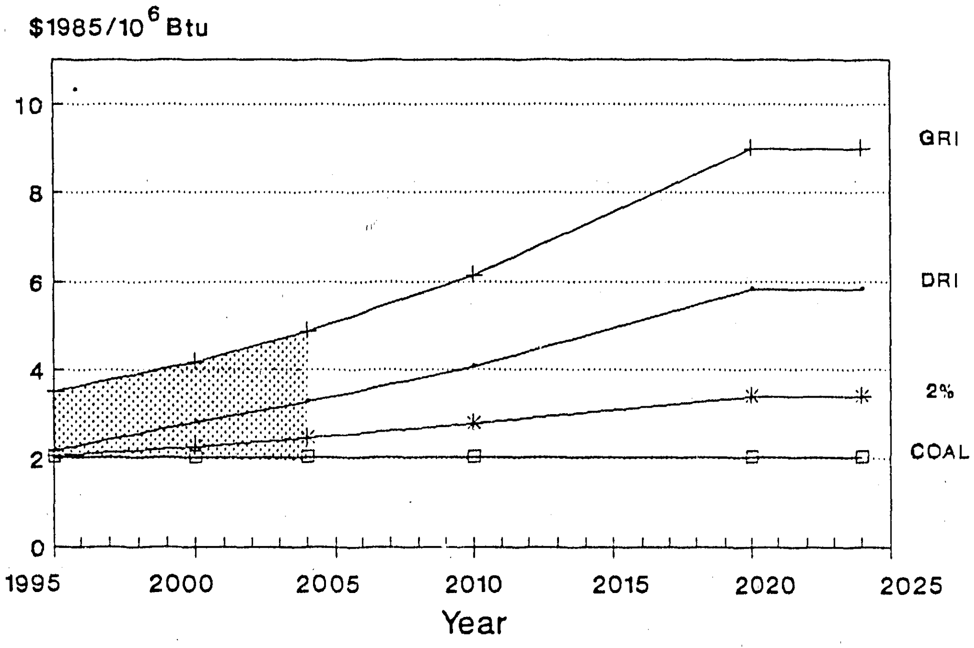


Figure 11. Power Pool 16: Dispatch of NGCC Technology Selected by Gas Price Track (10-Yr Planning Period)

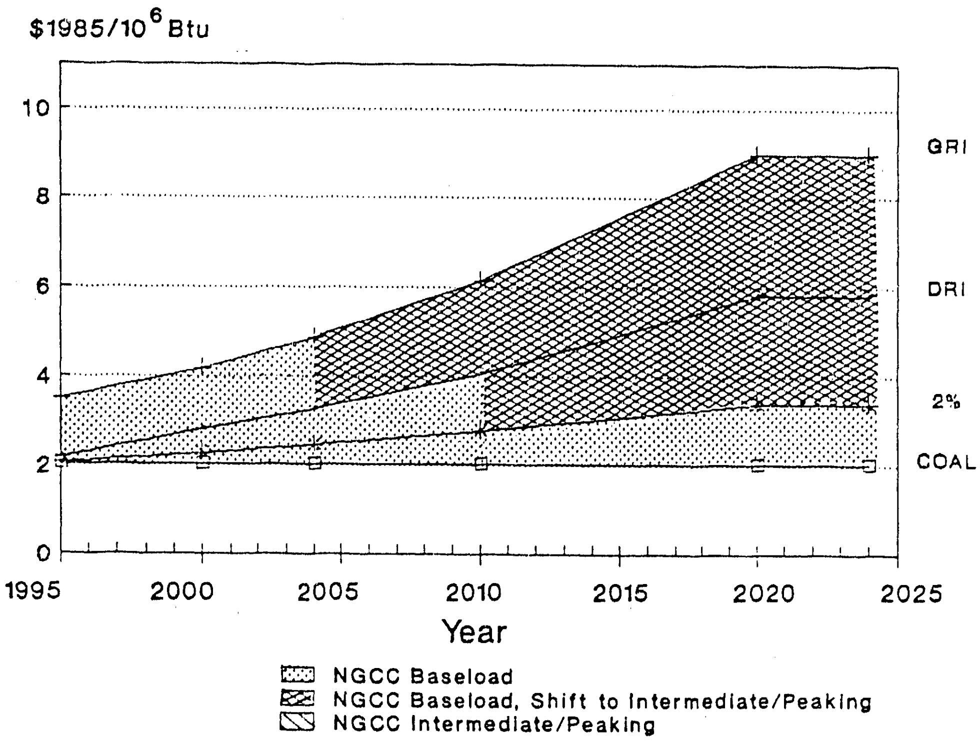


Figure 12. Power Pool 16: Dispatch of NGCC Technology Selected by Gas Price Track (30-Yr Planning Period)

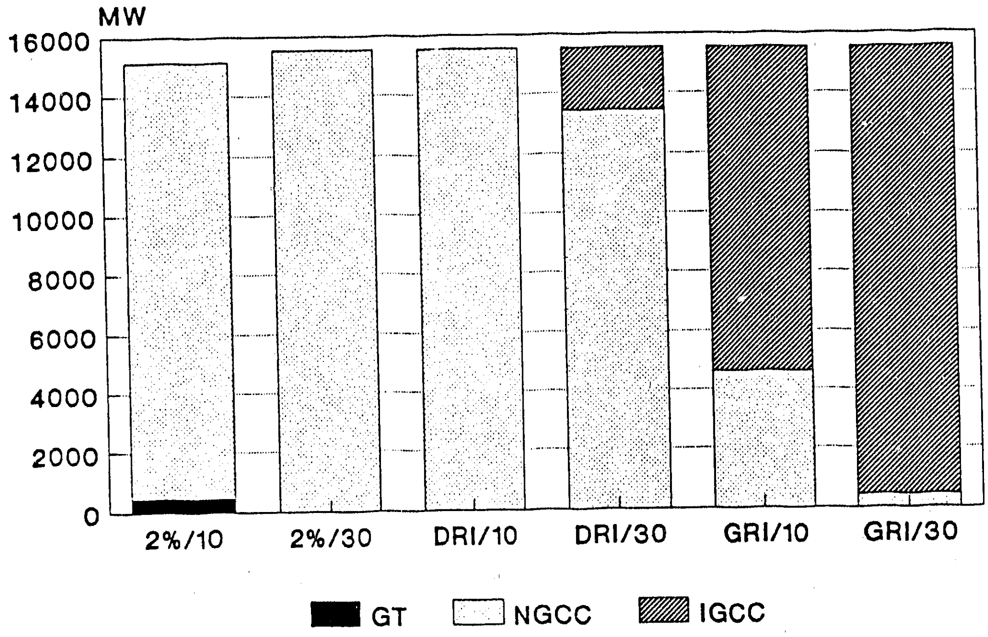


Figure 13. Power Pool 16: Cumulative Capacity Additions by Technology and Scenario, 1995-2004

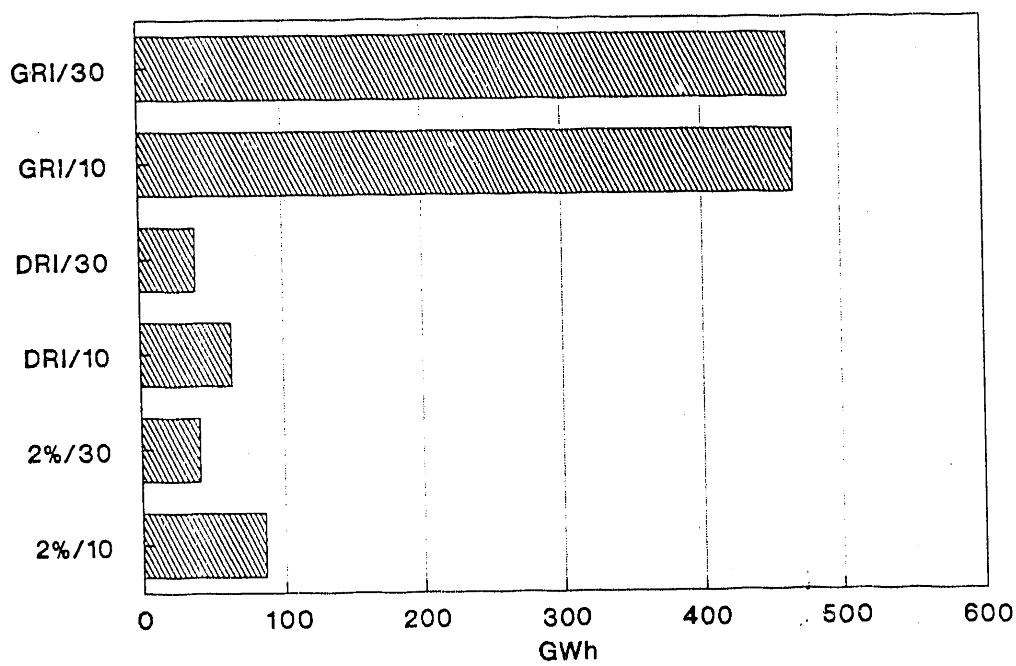


Figure 14. Power Pool 16: Cumulative Unserved Energy by Scenario, 1995-2004

Impact of Planning Horizon, 1995-2004. The impact of the planning period on the amount of new capacity added between 1995 and 2004 is only seen in the 2%/10 scenario, which has 390 MWe less capacity added than the amount in the other scenarios in 2004 (see Fig. 13).

The impact on technology choice during the 1995-2004 time period is mostly the result of the increase in gas prices and not the length of the planning horizon. In the 2%/30 scenario, two additional NGCC units and three less GT units are added than in the 2%/10 scenario. The 2%/30 scenario has one or two more NGCC units in each year from 1995 to 2004 than does the 2%/10 scenario. This situation occurs because the capital cost of NGCC units is offset by future fuel savings that are realized during the longer planning period. This change results in 45 GWh (or 109%) more unserved energy in the 2%/10 scenario than the 2%/30 scenario (Fig. 14).

IGCC units are introduced in the DRI/30 scenario after 2002 because the longer planning period allows the capital cost of IGCC units to be offset by future fuel savings. When IGCC units are introduced, older gas and oil units are operated as cycling units. The DRI/30 scenario has 20% less unserved energy from 1995-2004 since the build schedule for NGCC units is advanced in this time.

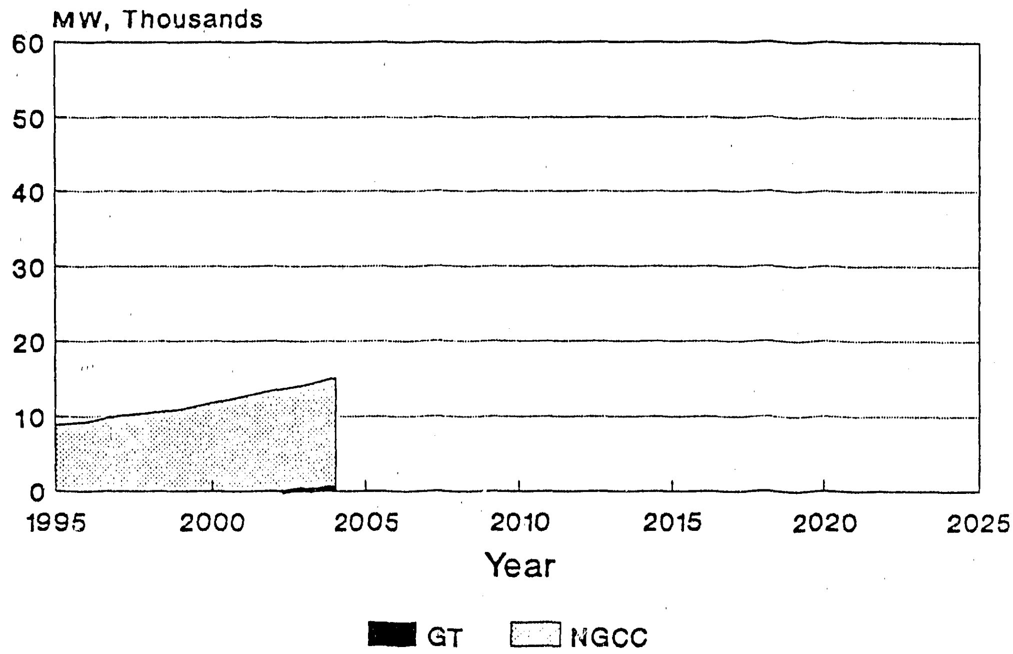
Like the DRI scenarios, the GRI/30 scenario introduces IGCC units earlier than does the GRI/10 scenario. The GRI/30 and GRI/10 scenarios result in significantly more unserved energy than do the other scenarios (see Fig. 14). The increase in unserved energy occurs mainly because IGCC units have a higher forced outage rate, which results in more unserved energy and a less reliable system.

Impact of Gas Price Tracks

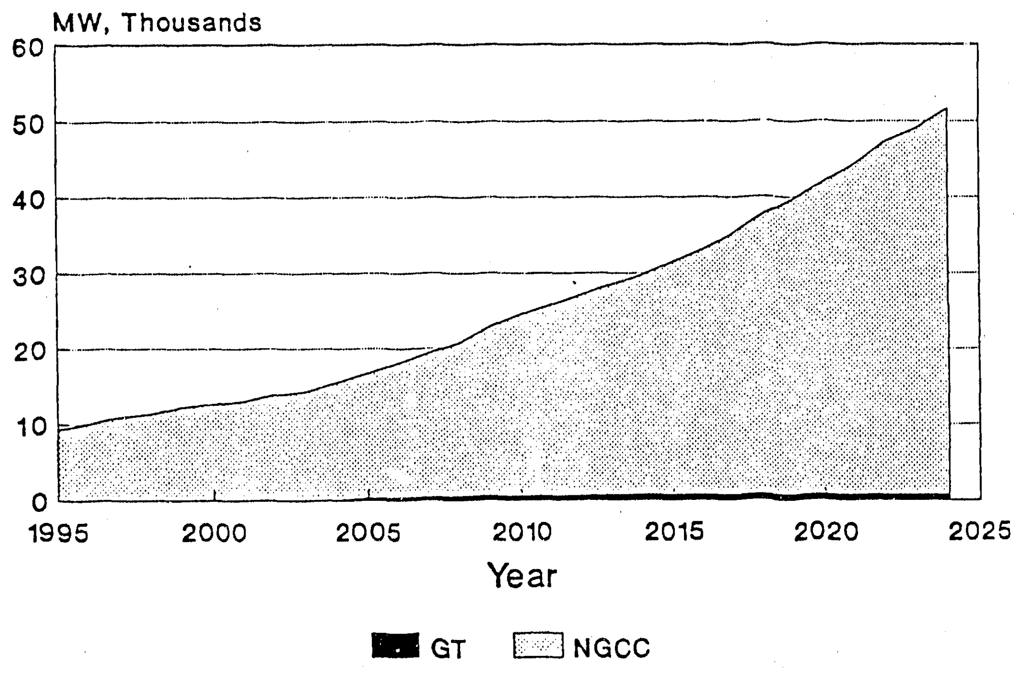
2% Gas Price Track: In the 2%/10 and 2%/30 scenarios, only NGCC units provide new base-load capacity throughout the planning periods (see Fig. 15). NGCC units are run at capacity factors between 50% and 70% throughout the planning period. A few GT units are added in each planning period for new peaking capacity.

DRI Gas Price Track: In the DRI/30 scenario, IGCC technology enters the build mix in 2003 because of increased gas prices. Figure 16 indicates that the technology of choice for new base-load capacity is altered in 2003 when the levelized gas price increases by $0.89/10^6$ Btu when going from the DRI/10 to the DRI/30 scenario. As IGCC units enter the solution, no NGCC units are added and existing NGCC units are operated as intermediate/peaking capacity (see Figs. 11 and 12).

The increase in levelized gas price of $0.46/10^6$ Btu results in an accelerated NGCC build schedule in the DRI/10 scenario when compared with the 2%/10 scenario. The DRI/10 scenario has one or two more NGCC units from 1998-2004 than does the 2%/10

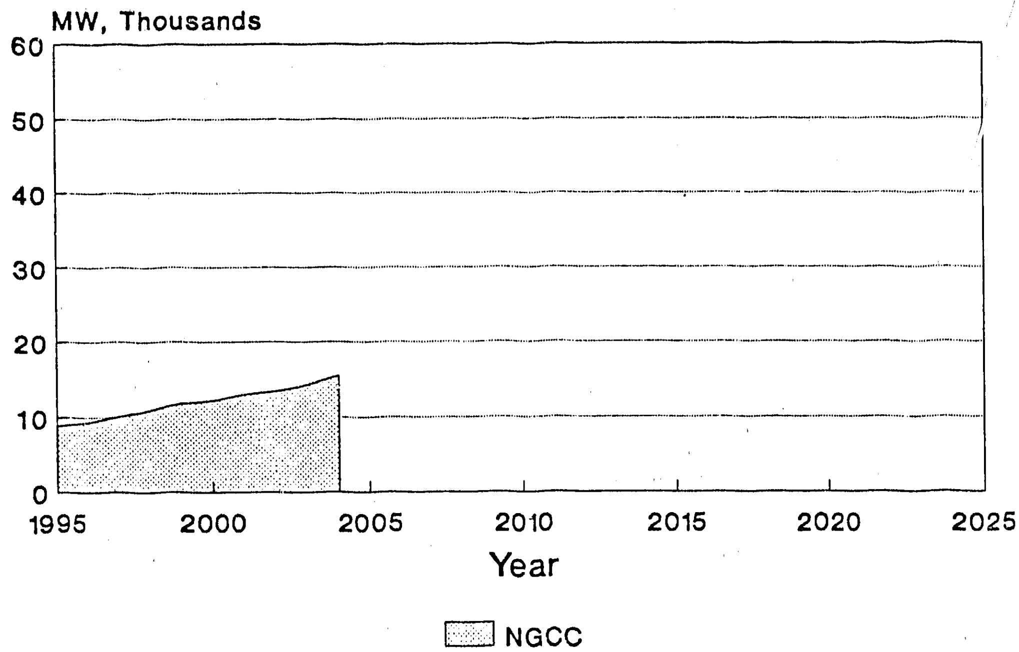


a. 10 Year Optimization

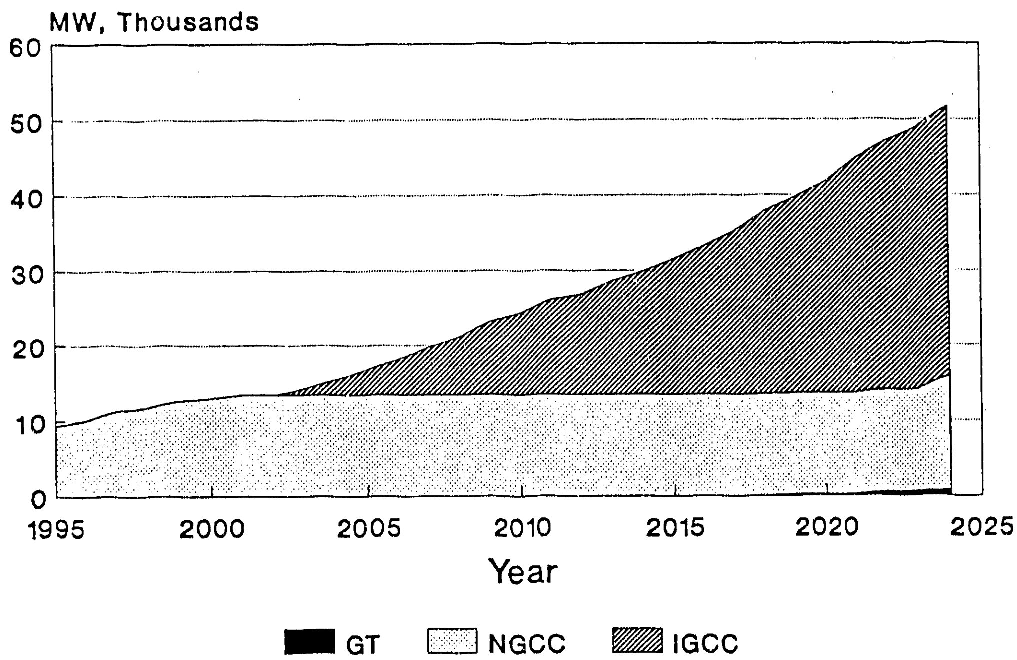


b. 30 Year Optimization

Figure 15. Power Pool 16: Cumulative Capacity Additions by Technology for 10-Yr and 30-Yr Planning Horizons: 2% Gas Price Track



a. 10 Year Optimization



b. 30 Year Optimization

Figure 16. Power Pool 16: Cumulative Capacity Additions by Technology for 10-Yr and 30-Yr Planning Horizons: DRI Gas Price Track

scenario. By 2004, DRI/10 has two more NGCC units and three less GT units than does the 2%/10 scenario. The increased capacity in the DRI/10 scenario reduces the unserved energy by 235 GWh (26.7%) from that of the 2%/10 scenario. The cost of bringing NGCC units on line sooner is economical at the higher DRI gas price because of the reduction in unserved energy (see Fig. 14).

GRI Gas Price Track: The increased gas price that occurs in going from the DRI to the GRI gas price track affects technology choice in both planning periods. In the GRI scenarios, NGCC units play a minor role in new capacity additions (see Fig. 17). The increase in the levelized gas price of $\$1.48/10^6$ Btu in going from the DRI/10 to the GRI/10 causes NGCC units to be added only in 1995. Similarly, only one NGCC unit is added in the GRI/30 scenario (1995), and no other NGCC units are added until after 2018.

In the GRI/10 scenario, the NGCC and IGCC units are added simultaneously in 1995. However, no additional NGCC units are added after 1995. The annual average capacity factor of NGCC units drops quickly from 74.2% in 1995 to 52.2% in 2004 in the GRI/10 scenario. The GRI/30 scenario adds one NGCC in 1995 and no others until 2019, and only five GT units are added from 2006-2024.

4.0 Global Findings

Results of this study show that the mix of new plants that is added to a power pool is affected by fuel price and length of planning period as well as system composition. Direct comparisons between the scenarios must be done with care, because each scenario has a different starting price for gas along with a different annual escalation rate.

The principal findings indicate that in almost all cases, gas-fired NGCC units are preferred for base-load and intermediate/cycling capacity in the 2% gas price track. However, in nearly all cases when the GRI price scenario is used, coal-fired IGCC units are preferred for new base-load capacity. Neither technology dominates in the DRI price track; power pool characteristics appear to affect technology choice and operating mode. Table 2 summarizes the IGCC and NGCC selections and operating mode for each pool by gas price track and planning period.

In the 10-year planning period, NGCC units were usually preferred for new base-load and intermediate/cycling capacity. This occurred because new gas units were not run in the future, when the gas price continued to escalate. Although the capacity factor of a unit may decrease over time, the unit will be run at some level until the end of the study. In the WASP methodology, once a new unit is selected and built, it is run throughout the planning period, regardless of the increase in fuel price. Less gas-fired capacity was

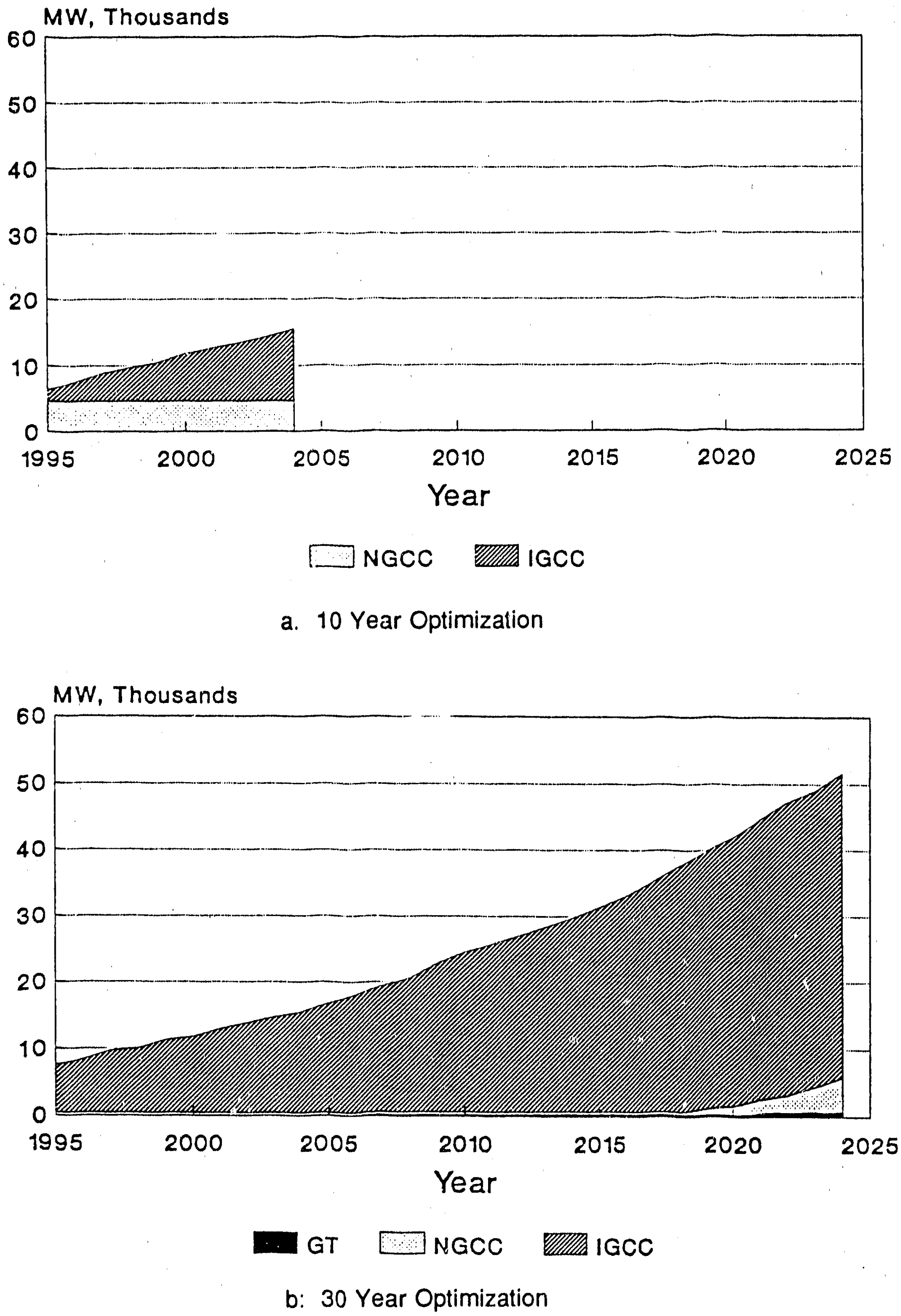


Figure 17. Power Pool 16; Cumulative Capacity Additions by Technology for 10-Yr and 30-Yr Planning Horizons: GRI Gas Price Track

Table 2. Technology Choices for New Unit Additions by Power Pool, Planning Period, and Gas Price Track[a,b]

Power Pool	10-Yr Planning Period (1995-2004) 2%	DRI	GRI	30-Yr Planning Period (1995-2024) 2%	DRI	GRI
1	NG[c]	NG[c]	IG	NG[c]/IG	IG	IG
5/6	NG[d]	IG	f	NG[c]/IG	NG[c]/IG	f
8	NG[c]/IG	IG	f	NG[c]/IG	NG[c]/IG	f
16	NG[d]	NG[d]	NG[c]/IG	NG[d]	NG[e]/IG	NG[e]/IG
19	NG[d]	NG[d]	IG	NG[d]	NG[d]	IG
20	NG[d]	NG[d]	IG	NG[e]/IG	NG[e]/IG	NG[c]/IG
25	NG[c]/IG	NG[c]/IG	f	NG[c]/IG	NG[c]/IG	f
26	NG[e]/IG	IG	f	NG[c]/IG	NG[c]/IG	f
27	IG	IG	f	NG[c]/IG	NG[c]/IG	f
28	NG[d]	NG[d]/IG	IG	NG[e]/IG	IG	IG

[a]IGCC units always operate as base-load capacity in all scenarios examined.
[b]NG/IG indicates that both technologies are selected.
[c]NGCC units operate as strictly intermediate/cycling capacity.
[d]NGCC units operate as strictly base-load capacity.
[e]NGCC units operate as base-load capacity and then switch to intermediate cycling capacity in future years.
[f]Scenario not run.

added in the 30-year planning period scenarios because of the continuous increase in gas price throughout the study period.

The composition of a power pool also influences the potential market for new technologies. A power pool that currently has a large amount of base-load coal and nuclear capacity is less likely to select NGCC units for new base-load capacity. NGCC units are not competitive with these units even at the lowest gas price track. This situation occurred in Power Pool 1. In the later years of the study, when the coal and nuclear units retire, the escalated gas price makes NGCC units uneconomical. However, in power pools that have a large share of oil and gas capacity (like Power Pool 16), NGCC units are competitive at all gas price tracks and study horizons because they can displace existing oil and gas units and they are more economical than new IGCC units.

The ability to meet peak load is provided in all these scenarios; however, the probability that there will be unmet load increases as the percentage of IGCC units increases. This analysis assumed that unserved energy would be met by additional purchases. There was no attempt to limit the amount of purchases nor was there an adjustment to demand in pools that would provide the additional purchases. If utilities with current excess capacity reduce their export energy to meet their internal load growth, increases in the cost of purchases over time can be expected. One way to reduce this impact is to select technologies that have a better availability or to invest in research that will improve the availability of less reliable units. Utilities may also consider additional plant(s) to reduce energy shortages. Comparing alternative expansion plans on a strictly least-cost basis excludes a critical component of the system -- namely, reliability. The requirement to maintain a reliability level would probably increase the cost of an expansion plan but would also provide a more consistent comparison among alternative expansion plans. Alternative expansion plans should have the same level of reliability before costs are compared.

In addition to the study of changes in the gas prices and length of the planning period, a limited sensitivity analysis was done on the cost of unserved energy for selected scenarios. In these scenarios, the base case for unserved energy was changed from $0.10 to $0.05 and $0.15/kWh. In those runs with a lower unserved energy cost, the tendency was to decrease the number of new units added and/or to reduce the rate at which new units were added to the system. This occurred because the system considered it more economical to pay for additional unserved energy than to build new units. Conversely, for those units with a higher unserved energy cost, the trend was to add additional units or to increase the number of units being built. However, in none of these sensitivity scenarios did the technology of choice change.

The results of this analysis indicate that many factors can strongly influence new technology choice within a region. Utilities should be aware of the uncertainties in their assumptions. The uncertainties associated with input parameters such as load growth, future fuel prices, and cost of new technologies require that multiple scenarios be developed and reviewed before a particular technology is chosen. Adding low-capital-cost NGCC units may solve near-term capacity needs but may not be economical over the long term. The ability to ask "what if" questions allows a utility to see whether and how its decision would be affected by future changes to critical parameters.

5.0 References

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