National Regulatory Research Institute

Increased Dependence on Natural Gas for Electric Generation: Meeting the Challenge

The National Regulatory Research Institute

NRRI 04-04

INCREASED DEPENDENCE ON NATURAL GAS FOR ELECTRIC GENERATION: MEETING THE CHALLENGE

Ken Costello
Senior Institute Economist
614-292-2831
Costello.1@osu.edu

The National Regulatory Research Institute
at The Ohio State University
1080 Carmack Road
Columbus, Ohio 43210
Phone: 614-292-9404
Fax: 614-292-7196
www.nrri.ohio-state.edu

April 2004

This report was prepared by the National Regulatory Research Institute (NRRI) with funding provided by the member commissions of the National Association of Regulatory Utility Commissioners (NARUC). The views and opinions of the author do not necessarily express or reflect the views, opinions or policies of the NRRI, NARUC or NARUC member commissions.

EXECUTIVE SUMMARY

The rapid growth of gas use for electric generation raises concerns over what effect this could have on the reliability of electric power systems. Many new gas-fired power plants lack dual fuel capability, and the delivery of natural gas to them is predominately transacted on an interruptible basis. Regional electric power operators/planners have acknowledged a potential problem and some, particularly those in the Northeast, have conducted studies to assess the adequacy of the regional gas pipeline system in meeting the demands of both electric generators and traditional customers. The North American Electric Reliability Council (NERC) has also been actively involved in examining the reliability aspects of new gas-fired power plants. Finally, the North American Energy Standards Board (NAESB) is investigating whether to revise standards to enhance coordination between the scheduling of electric and gas transactions.

Regional electric power operators face a potential dilemma in achieving the goals of low wholesale electricity prices and high reliability. The decisions of gas-fired generators to purchase non-firm gas transportation service and to not invest in dual-fuel capability are largely driven by economics. In some regions generators face intense competition and, thus, have a strong incentive to control their costs. More reliable electric service from gas-fired power plants would likely increase the generation costs of such facilities.

As underscored in this report, the potential problem posed by gas-fired generators is largely the responsibility of the regional electric system operator/planner, who must assess the presence of these generators on the system's reliability, particularly with regard to operational security. Theoretically, the operator/planner should then evaluate whether "forcing" or encouraging gas-fired generators to become more reliable (for example, by requiring them to have firm gas transportation service) would be beneficial to electricity consumers. At the least, and as recommended by most studies reviewed for this report, electric power system and gas transportation operators should better communicate with each other and, if feasible and economical, more formally coordinate their activities.

TABLE OF CONTENTS

FOREWORD

Increasingly natural gas is being used for electric generation. Concerns have recently arisen in some regions of the country over the reliability of gas-fired generating facilities because of the predominance of non-firm gas-transportation arrangements and the inability of many new gas-fired power plants to burn oil as an alternative fuel. Some regional electric power organizations as well as other groups have conducted studies on the potential reliability problems posed by gas-fired generation. This report reviews these studies and offers some insights into policy implications. It is hoped that this report will assist state public utility commissions in addressing this topical issue.

Raymond W. Lawton
Director, NRRI
April 2004

ACKNOWLEDGMENTS

The author wishes to thank Mr. Bob Harding and Mr. Ron LeComte for their comments on an earlier draft of this report. He also appreciates the fine editing of an earlier draft by Ms. Kate Harwood. Finally, the support and helpful comments of Dr. Vivian Witkind Davis are thankfully acknowledged. Responsibility for the content of the report is the author's alone.

INTRODUCTION

The proliferation of natural gas fired generating units since the early 1990s has caused upward pressure on natural gas prices as well as increased demands on gas transportation systems. In the 1970s and 1980s most new generating capacity was either coal-based or nuclear. In the 1980s several nuclear plants that began construction in the1970s were completed, but no new nuclear plants were built. Gas-fired plants using combined-cycle technology started to be built in the early 1990s.[1] The surge of new gas-fired generating power plants has become a world-wide phenomenon. The major reasons for this are economics and the environmentally benign nature of gas-fired generation.

For many of the new gas-fired generating units, gas transportation is negotiated on an interruptible basis,[2] raising concerns about their availability for electricity generation under tight conditions on the regional gas pipeline network.[3] Aggravating

---

[1] Over 90 percent of new generation capacity since 1996 has been gas-fired. The latest North American Electric Reliability Council (NERC) projections, as of this writing, show that gas-fired capacity will represent over 38 percent of the total electric generating capacity for the summer of 2008; in comparison, capacity fired by gas was 23 percent of total electric generation capacity as recently as 1998. According to most forecasts, almost 50 percent of the growth in the demand for natural gas over the next two decades will derive from power generators. The tightness of the natural gas market over the past few years, as well as for the foreseeable future, can partially be attributed to the dramatic rise in gas consumption for electric generation. Over the period 1990-2003, the demand for natural gas by electric generators grew by about 60 percent, or by an average annual growth rate of 3.6 percent. By comparison, over the same period the total demand for natural gas grew by a little over 15 percent.

[2] Typically, unused firm gas transportation reverts to the pipeline, which it sells as interruptible transportation service. In other words, a pipeline inherits interruptible service from customers who fail to exercise all of their firm transportation rights. Rates for interruptible service, which is sometimes referred to as “best efforts” service, can be substantially lower than rates for firm service. Gas pipelines are governed by a physical rights (or entitlement) system. Pipelines are required to offer transportation contracts with gas shippers that give them the physical right to transport gas from one point to another on their pipeline system; these rights are tradable, subject to regulatory price caps. Rights holders who do not use their rights to support transport of gas by a certain time period prior to any particular transportation date are required to “release” those unused rights for sale to other shippers and consumers in the gas transportation market.

[3] Much of the growth in gas consumption in recent years has been met with new pipelines or extensions from new supply areas, rather than expanding existing infrastructure in existing areas. Additional capacity is also being developed by increasing compression on existing pipeline systems and by looping (integrating a parallel pipeline). Over the past few years, the Federal Energy Regulatory Commission (FERC) has certified several new laterals extending from existing pipeline systems to new gas-fired power plants. In 2002, for example, twelve laterals accounted for about 26 percent of the total new gas pipeline capacity added to the network that year. Also, 2002 saw the construction of a number of smaller pipeline laterals dedicated to gas-fired generating units. See Energy Information Administration, Office of Oil and Gas, Expansion and Change on the U.S. Natural Gas Pipeline Network – 2002, May 2003. Undeniably,

the problem is the lack of dual-fuel capability for many of the new gas-fired units, posing a potential problem for a regional electric system when natural gas is unavailable. Some regions of the country, for example Texas and the Northeast, rely heavily on the deliverability of natural gas to generating units that have increasingly operated during non-peak periods. During the winter of 2003-2004, severe weather in New England placed stress on both the region's electric power and gas pipeline systems.[4]

Policy Concerns

Attention over the increased use of natural gas for electric generation has stimulated debate, particularly on the ability of gas-fired units to provide reliable electric power during peak as well as non-peak periods. These concerns have been articulated by a wide spectrum of groups including state public utility commissions and energy agencies, independent system operators (ISOs) and other regional electric system operators, the North American Electric Reliability Council (NERC) and individual reliability councils, the Federal Energy Regulatory Commission (FERC), the North American Energy Standards Board (NAESB), and the Edison Electric Institute (EEI). The prevailing view is that the growing reliance on natural gas for new generating capacity can impose greater reliability risk on both the electric power and natural gas networks. Specifically, short-tem problems caused by gas pipeline constraints could seriously affect the security of an electric power system. NERC defines security as the ability of the system to withstand sudden disturbances (that is, contingencies), which encompasses the inability of a generator to receive natural gas.[5] It is this dimension of electric system reliability that is most directly pertinent for this report.

Although not explicitly addressed here, a highly important national policy question is whether the United States should promote the use of non-gas sources of energy to supply new generating facilities and, if so, with what specific policies. One

---

the construction of laterals will place more demands on existing pipelines since gas flowing over laterals must originate on main lines.

[4] See, for example, Stephen G. Whitley, "New England Power System Operations Under Extreme Winter Conditions," January 2004.

[5] A contingency is defined as an unexpected failure or outage of an electric-power-system component. Such events reduce the availability of generation to serve load. Forcing a generating unit to shut down because of a bottleneck on the gas transportation system illustrates one example of a contingency.

argument put forth recently is that because of the high volatility of natural gas prices, any capacity expansion decision should account for this fuel price risk.[6] By incorporating this element into the planning equation, other sources of energy such as renewables may become not only more attractive but even preferred from an economic perspective.[7] There is also the issue of whether we have overly restricted the use of non-gas sources of energy for electricity generation by distorting the trade-off between environmental/safety and energy goals. For example, we may have overstated the social costs of nuclear power and coal-fired generation.[8] Renewable energy may become economical at some future period, but it is not expected to comprise a significant share of new generating capacity for the next 10 to 20 years.[9] Currently, renewable energy (excluding hydro) comprises about 2 percent of electric generation in the United States. Renewable energy has been significantly hampered by its intermittency and low rates of capacity utilization. In addition, because wind turbines cannot be cycled in the same way that other generating units can, they are incapable of following load. For the time being, apparently, we are "stuck" with natural gas fueling new power plants, unless major policy initiatives or technological breakthroughs favorable to non-gas sources of electric generation come on the scene. One such policy initiative would be an aggressive stance on abating carbon dioxide emissions, say, through a carbon tax or a "cap and trade" system, which would make nuclear power and renewable energy more attractive relative to fossil fuels.

[6] See, for example, Mark Bolinger et al., "Quantifying the Value That Wind Power Provides As a Hedge Against Volatile Natural Gas Prices," Proceedings of WINDPOWER 2002, Portland, Oregon, June 2002.
[7] This assumes that end-use consumers place some value on price stability, which seems to be consistent with the limited empirical evidence available. The tough question is how much consumers are willing to pay to have more stable prices.
[8] A recent MIT study identifies different, perhaps insurmountable, obstacles to the development of nuclear power. It starkly stated that "[t]he nuclear power option will only be exercised…if the technology demonstrates better economics, improved safety, successful waste management, and low proliferation risk, and if public policies place a significant value on electricity production that does not produce CO_2." See Massachusetts Institute of Technology, The Future of Nuclear Power: An Interdisciplinary MIT Study (Cambridge, MA: MIT, 2003), vii. Compared to coal, natural gas is much more environmentally benign by emitting substantially less air pollutants (nitrogen oxide, sulfur dioxide, carbon dioxide and mercury), in using less land, and in consuming less water.
[9] See Joel Darmstadter, "The Economic and Policy Setting of Renewable Energy: Where Do Things Stand?" Discussion Paper 03-64 (Resources for the Future), December 2003.

Focus of the Report

This report has the primary objective of discussing and analyzing the potential problems resulting from the increased reliance on gas-fired generation. At first glance, it is not obvious that a serious problem exists to warrant additional initiatives by policymakers. Electric generators are presumably making economically rational decisions when it comes to purchasing non-firm gas pipeline capacity and not investing in dual-fuel capability. After all, in many regions they face intense competition and, therefore, have strong incentives to control their costs. Regional electric system operators/planners are presumably accounting for the potential reliability effects of gas-fired generating units lacking both dual-fuel capability and firm gas transportation. The Northeast region in particular has been investigating the reliability of gas-fired generating units. If these observations accurately describe the current situation, then one must ask whether a problem exists and, if so, its source and nature.

Policy and institutional factors have, however, legitimately raised the real possibility of particular problems transpiring that could jeopardize the reliability of electric power systems. These problems could spread to natural gas consumers other than electric generators. As a matter of principle, policymakers should be judicious in taking action only when it is expected to improve matters overall. They should not overreact by implementing counterproductive policies. For example, requiring electric generators to sign firm contracts for gas transportation could drive up the price of electricity as well as reduce the reliability of gas service to traditional gas customers. Forcing new electric generators to invest in dual-fuel capability could also have an adverse effect, for example, by acting as a barrier to entry in restructured electric-generation markets. A review of activities taken in response to these potential problems, which is a major part of this report, strongly suggests that the different regions of the country where the gas-fired generation problem is most likely to occur have started to give high priority to addressing it. Organizations such as NERC, NAESB and FERC have also acknowledged the need to study the problem and take appropriate actions, whatever they may be. Almost all industry observers agree that the electricity and natural gas sectors should be better integrated to some degree.

Integration in this context means either cooperation or coordination. Cooperation might include information sharing, while coordination might involve each party adjusting it operations in order to achieve some agreed-upon common goal. How this should be done and by whom remains unanswered at this point in time.

This report provides insights on three potential problems associated with the increased use of natural gas for electric generation: (1) the risks associated with long-term and short term regional gas pipeline bottlenecks, (2) non-firm gas pipeline transportation and (3) limited dual-fuel capability of new generating units. Several previous studies assessed the nature and severity of these problems. Specifically, they assessed the adequacy of the existing and planned gas pipeline capacity to reliably supply current and future coincidental demands for gas utilities, gas marketers and electric generators. This report highlights the major evidence and conclusions from these studies. Finally, it will comment on the policy implications from those studies as well as from the independent evidence compiled for this report.

THEORETICAL PERSPECTIVE ON RELIABILITY CONCERNS

The crux of the problem addressed in this report can be expressed as the following: *Does the rapid growth of gas-fired generation pose reliability problems on regional electric systems that have not been accounted for by the system operator/planner?* That a gas-fired generator has features that reduce its reliability on a regional grid by and in itself may not pose a serious problem. The value of a generating unit, for both its owner and the regional electric power system, depends in part on its reliability.[10] In regions, for example, with an electric capacity market, if an individual generating unit has lower reliability for whatever reason, it will receive lower payments from the system operator.[11] If a region has serious gas-pipeline capacity constraints[12] and assuming that a generating unit has interruptible pipeline service, the system operator should take that into account in quantifying the system-reliability effect of the unit. When a unit has lower reliability, from a long-run perspective it might result in the regional electric network having to purchase more generating capacity to achieve a targeted level of system reliability (for example, loss-of-load probability of one day in ten

---

[10] See Steven Stoft, Power System Economics: Designing Markets for Electricity (Piscataway, NJ: IEEE Press, 2002).

[11] In the Northeast, such a market is referred to as the installed capacity market (ICAP). ICAP payments represent revenues to the generator for use of its plant as reserve to meet peak demand. There has been intense debate over whether restructured wholesale electricity markets should impose a capacity requirement. The standard approach to price-risk management in competitive commodity markets is forward contracting, where market participants agree to buy and sell a fixed quantity of a commodity at some given price for a specified future time period. Some proponents of a capacity market see it as a "second best" solution to ensure adequate supplies in view of the political infeasibility of allowing unstable prices in the short-term energy market. Other industry observers consider a capacity market as necessary for other reasons: (1) capacity is a positive externality in providing reliability benefits to all users of the electric power grid, and (2) energy prices fail to internalize the full social benefits of capacity. Opponents of a capacity market argue it is inefficient and unnecessary under real-time metering and forward contracting.

[12] These constraints may restrict or interrupt fuel supply to gas-fired generators. A pipeline-capacity constraint occurs when natural gas is in sufficient supply, but an unexpected event causes a brief interruption in gas movement to customers, often on only a section of the pipeline.

years).[13] In the short run, it may mean a less secure system, with modified procedures required by the system operator.[14]

Perhaps then the most serious problem reduces to a question of whether the short-run and long-run value of power from gas-fired generators to the region, accounting for their reliability as well as other attributes, accurately reflect the price received. Theoretically, as long as the generator fully internalizes its decisions – for example, from the purchasing of interruptible gas pipeline services and from not acquiring dual-fuel capability – there would be little rationale for special intervention by the regional system operator. On the other hand, most economists would agree that the security of an electric power system, hinging upon operating decisions, is a public good where intervention by a central operating/planning entity is required.[15] A public good has inherent externality and free-rider problems, which most experts agree are embedded in the security function of an electric power system.

The previous discussion implies minimal market and regulatory distortions in terms of uneconomical behavior by the owner of the generating unit or regional electric power operator/planner. One possible defect, or counterexample, is the setting of pipeline rates. If one could demonstrate, for example, that interruptible service is priced too low relative to firm service, then it could be inferred that the generator is purchasing

[13] Loss-of-load-probability (LOLP) studies typically calculate the amount of required capacity, but generally they fail to account for several factors that substantially affect the distribution of available capacity – one being common-cause failures that result in multiple generating units not being available at the same time. This could happen, for example, if bottlenecks on a regional gas pipeline system curtail gas delivery to all of the gas-fired facilities in the affected area. (LOLP is defined as the probability that demand exceeds supply within a period of time, for example within a year under specified set of assumptions.) See Frank A. Felder, "Incorporating Resource Dynamics to Determine Generation Adequacy Levels in Restructured Bulk Power Markets," unpublished paper, Sept. 24, 2003.

[14] As mentioned above, NERC defines security as "the ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements." In comparison, the second component of reliability, adequacy, is defined by NERC as "the ability of the electric system to supply the aggregate electrical demand and energy requirements of the customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements."

[15] See, for example, Shmuel S. Oren, "Ensuring Generation Adequacy in Competitive Electricity Markets," unpublished paper, June 3, 2003.

excessive interruptible service relative to other available pipeline services.[16] Such a problem would have to be addressed by FERC since it involves gas-pipeline ratemaking. As discussed below, it has been argued that the availability of low-priced interruptible service has stifled the expansion of gas pipeline capacity. As another possible distortion, limited dual-fuel capability might be the result of environmental restrictions that, from an economic perspective, are overly stringent. Decisions on environmental protection are beyond the purview of the regional power operator or similar entities as well.

Regarding non-firm gas pipeline transportation, the reason for its popularity with gas-fired generators is strictly economic in nature. A study done for the New York ISO and the New York State Energy Research and Development Authority (which is reviewed below) explains it quite succinctly. The study argued that gas-fired generators generally make most of their profits during summer months when excess gas pipeline capacity is available at low rates. These generators can purchase non-firm service in the summer and have little fear of being curtailed. In the winter months, electricity rates are usually lower and pipeline rates higher. Thus, generators would suffer fewer profit losses during the winter if curtailed. Because gas prices and gas transportation costs are often at their lowest when electric prices are at their highest, generators are able to reap substantial margins without the need to contract for higher-priced firm gas pipeline capacity.[17] The crucial question is whether the unwillingness of generators to enter firm contracts could seriously thwart gas pipeline expansions, as FERC's policy in approving new pipeline projects requires sufficient contractual commitments (recent FERC

---

[16] In its Order 637, FERC expressed concern that gas pipeline customers were relying excessively on short-term service, including interruptible service, relative to long-term service. Comments filed by pipelines argued that they are forced by market forces to discount their prices for released capacity and short-term firm and interruptible services during off-peak periods. During peak periods, they contended, they are barred by FERC from charging prices that would recover the full market value of their services. Overall, this pricing constraint deprives them of the opportunity to compensate for the low prices sustained during off-peak periods and, in effect, results in cost shifting from interruptible to firm customers.

[17] These margins are referred to as the "spark spread," which is defined as the difference between electricity price and the fuel cost of generation – i.e., electricity price minus the product of the natural gas price and the plant's heat rate. With a heat rate of 7,000 Btu per Kwh, which approximates the heat rate of new combined-cycle gas facilities, for every dollar increase in the gas price, assuming electricity prices are held constant, the spark spread decreases by $7 per Mwh. Some gas utilities offer electric generators an interruptible transportation service that ties the rate to the spark spread. This represents an example of value-of-service pricing.

decisions indicate a minimum of 30 percent) from purchasers of capacity to cover pipeline construction costs.[18]

The lack of dual-fuel capability for many new gas-fired generating units can also be explained by both economics and environmental/land use restrictions. Major impediments to fuel switching include (1) environmental permits, (2) physical constraints, (3) additional costs to the generator and (4) local zoning regulations that often do not permit the construction of oil storage tanks. An example of a substitute for dual-fuel facilities would be single-fuel generating units that burn a non-gas source of energy. We observe what is called "seasonal indirect switching" on many electric power systems, where gas-fired generating units are shut down during the winter to be displaced by coal-fired generation. Power systems also commonly switch from natural gas to oil or other fuels during the winter regardless of relative prices. Fuel switching or local natural gas storage[19] can act as a substitute for expanding pipeline capacity in that with less switching capability additional pipeline capacity would be needed to achieve a given level of reliability for the regional electric power system.

The protocol for curtailing customers in response to interstate pipeline bottlenecks and other supply-constraint situations can be critical for the reliability of an electric power system. The current policy established by FERC from its various orders is that *any curtailments owing to capacity constraints generally depend on how contract rights are spelled out for transportation customers*. With some exceptions, gas pipelines do not curtail on the basis of end-use consumption of gas. In recent years FERC has provided some guidance on the matter of pipeline curtailment protocol.

[18] In 1999 FERC issued a policy statement that provides guidance on evaluating proposals for certifying construction of new interstate gas pipeline facilities. The policy statement emphasized that FERC will weigh the public benefits against the potential adverse effects. FERC specified its goal to give consideration to (1) the expansion of alternative competitive alternatives, (2) the possibility of overbuilding, (3) subsidization by existing customers, (4) the applicant's responsibility for unsubscribed capacity, (5) the avoidance of unnecessary disruptions of the environment and (6) the unnecessary exercise of eminent domain. FERC articulated its intent to require pipelines proposing new facilities to present financial support that does not require subsidization from existing customers. The pipeline also must attempt to minimize any adverse effects of the proposed facility on existing customers. FERC has allowed rolled-in pricing of new pipeline capacity when it increases reliability to all shippers and results in a minimal rate increase (for example, 5 percent or less); otherwise, FERC requires incremental pricing.

[19] Propane-to-air and liquefied natural gas (LNG) storage, however, may not generally be an economical alternative for supplying natural gas to electric generators. Local, or market area, underground storage may also have operational limitations that prevent it from being an economical substitute for pipeline capacity serving electric generators. The author thanks Bob Harding of the Minnesota Public Utilities Commission for providing this insight.

Specifically, when some or all of a pipeline's capacity is constrained, present FERC policy generally treats electric generators no differently from other firm services–that is, a pipeline's existing firm customers enjoy no preferential treatment by the fact of their incumbency. In its *Koch Gateway* order, FERC declared that incumbent capacity holders, when faced with new services offered to other customers such as electric generators, have no right to expect a pipeline to maintain unsubscribed capacity in order to minimize the possible effects of a curtailment.

FERC has recognized the difficulty of achieving the right balance between promoting efficient pipeline capacity services for electric generation loads and continuing to serve dependably, without impairment, the traditional firm customer capacity uses. FERC has reasoned that with a growing menu of options for unbundled pipeline capacity service, customers should rely on private contracts, prudent planning and the market to the maximum extent practicable to secure their capacity needs.

Most industry experts interpret FERC policy to mean that pipeline capacity curtailment plans "generally" are operated under an approach that calls for pro rata allocation[20] of contract rights, but with the allowance of end-use measures to provide for "emergencies." For example, FERC has approved capacity curtailment settlements providing for different degrees of end-use allocation – namely, gas will continue to flow to those who need it for heating or other important needs, notwithstanding a pipeline's contract-based pro rata curtailment plan. If this interpretation of FERC policy is correct, electric generators essentially have the same rights to service as other customers, as long as they have firm contracts with a pipeline. This can be a concern at the state level, for both state public utility commissions and gas utilities, as the increased use of pipelines for transporting natural gas to power plants may impair the reliability of existing services of incumbent customers.

One emerging issue at the state level is the curtailment protocol for gas-fired generating facilities. For example, California has addressed this issue by asking whether gas-fired generating facilities should have priority over other non-core customers. In 2002, the California Public Utilities Commission ruled to not give electric

[20] Pro rata allocation refers to the method of allowing all customers within a specified group to receive the same proportion of natural gas available as their share of total volumes under contract.

generators priority over other non-core customers. There was concern that such a curtailment protocol could jeopardize gas service to other non-core customers, many of whom provide essential goods and services to the state. In its order, the Commission noted that those electric generators holding gas storage rights should be able to ensure natural gas service even if system curtailments transpire.

HIGHLIGHTS OF PERTINENT STUDIES AND ACTIVITIES

Several studies have been conducted on identifying problems for electric power systems as they increasingly depend on natural gas for generation. One study, for example, explicitly stated that its purpose was to address concerns about the adequacy of the New York gas delivery system for jointly satisfying traditional gas demands and future gas demands for electric generation. These studies, largely funded by the regional ISOs, have concentrated on the Northeast. Recently, FERC held conferences on the adequacy of the regional electric, gas and other infrastructure. These conferences were intended to identify current infrastructure conditions, needs, and investment and other barriers to expansion. Finally, NERC in its recent annual *Reliability Assessment* report has identified the unavailability of gas supplies to electric generators as a potential problem for regional electric reliability. NERC has considered this a serious enough problem to form a task force, called the Gas/Electricity Interdependency Task Force (GEITF), to evaluate the interdependency between gas pipeline operation/planning and electric system operation/planning reliability over a ten-year time horizon. There are additional activities at the state level addressing the interdependency between natural gas and electricity. Some of these studies and activities are highlighted below.

New England

In New England, gas requirements for power generation alone could approach or exceed use in traditional local gas distribution markets. In 1999, gas-fired generation accounted for about 16 percent of New England's total electric consumption; this is expected to rise to 41 percent in 2003 and almost 50 percent by 2010.[21] Currently, natural gas is the leading source of fuel for electric generation in New England. In 2004, New England's monthly load factor for gas pipelines is expected to exceed 90

[21] ISO New England has added almost 9,400 MW of generating capacity, with about 98 percent of this capacity gas-fired, since 1998. Only 6 percent of this gas-fired capacity has dual-fuel capability. In its 2003 Standard Market Design Implementation Report, ISO New England noted that the dramatic rise in natural gas prices during the winter of 2002-2003 "added volatility and caused a corresponding general increase in electricity prices for both the day-ahead and real-time electricity markets."

percent over three months of the year (winter months). This obviously reflects little redundant capacity on gas pipelines during peak periods.

In response to the current situation, ISO New England (ISO-NE) has conducted a number of studies focusing on the capability of the gas pipeline system to supply the energy needs of the region. The most recent ISO-NE fuel diversity assessment was conducted as part of the 2003 regional transmission expansion plan. It concluded that increased reliance on gas for electric generation "has potentially negative system-wide impacts"; as highlighted in the assessment, this would most likely occur during the winter months with pipeline interruptions or extremely cold weather. The ISO has formed a fuel diversity working group to address the potential reliability problem of deficient fuel diversity. Membership includes representatives from New England Power Pool, ISO-NE, industry personnel and state and regulatory officials.

A 2001 study for ISO-NE pointed out that the brunt of any gas pipeline shortfalls will be borne by those electric operators who do not have firm transportation contracts. The study also observed that the amount of merchant generation unable to burn natural gas does not necessarily lead to a shortfall in generation: merchant generators may be able to switch quickly to distillate oil, furnish pressure on-site, or to the extent older dual-fuel boilers are able to burn residual fuel oil, ISO-NE should be able to maintain grid security. A 2002 study concluded that the majority of merchant generators have not contracted for long-haul, primary, firm transportation rights; thus, they cannot be assured of firm deliveries during the coldest part of winter when each of New England's pipelines typically run at maximum capacity.[22] A study in 2003 warned that the lack of a well-diversified fuel portfolio for wholesale power production and minor fluctuations in gas supply or transportation availability could have a disruptive effect on the region. [23] The study pointed out that competitive pressures among gas-fired merchant generators in New England do not reward fuel diversity, nor are these generators required to acquire firm transportation rights to ensure gas deliverability during the heating season. As the study concluded, the decline in fuel diversity for electric generation raises

[22] Levitan & Associates, Inc., Steady-State and Transient Analysis of New England's Interstate Pipeline Delivery Capability, 2001-2005, prepared for ISO New England, February 2002.
[23] Levitan & Associates, Inc., Natural Gas and Fuel Diversity Concerns in New England and the Boston Metropolitan Electric Load Pocket, prepared for the ISO New England, July 1, 2003.

concerns about energy reliability in the region. The study highlighted the importance of prompt communications between gas utilities, pipelines, gas-fired generators and electric system operators to minimize the impact of a contingency.[24] This is consistent with one of the recommendations of a NERC task force that calls for the development of an inter-industry strategy for common education, planning and emergency response, including an emergency communications protocol between electric system and gas pipeline operators. The New England study also identified gas-fired generation as at-risk when projected amounts of generation cannot be served on each pipeline because of pipeline congestion during extreme winter weather conditions.

A recent Governor's Task Force in Massachusetts made several findings and recommendations related to the use of natural gas for electric generation.[25] First, interruptible gas pipeline service to electric generators can adversely affect the reliability of electric service. This would be especially true during the winter months. For example, during the extreme winter conditions of January 2004, almost all nonfirm transportation contracts involving electric generators were interrupted. Second, the gas pipeline system and the supply of gas in New England are sufficient to provide service for electric generation with firm gas transportation contracts. Third, ISO-NE has undertaken different initiatives to "facilitate communication and coordination between the gas and electric system operators in times of emergency on either system," but more should be done. Fourth, fuel-switching by gas-fired generators may increase electric reliability, but environmental/land use, economic and operational obstacles pose serious challenges. Fifth, Massachusetts should encourage fuel diversity in electric generation to improve the reliability of electric service. Sixth, ISO-NE should review its exiting market rules to ensure adequate incentives for promoting fuel switching and fuel diversity by electric generators, as well as to assess "if appropriate pricing signals would

---

[24] The Northeast Gas Association in its Northeast Natural Gas Market Update (October 2003) also emphasized the essential role of "increased coordination and communication between electric and gas systems in [the] new power market. Market dynamics are changing quickly and greater coordination among all market participants can help to ensure greater system stability, efficiency and reliability." The association noted that the tight natural gas market "reinforces the need for New England and New York to strengthen wherever possible the robustness of their natural gas systems and the diversity of their gas supply sources."

[25] The Governor's Task Force on Electric Reliability and Outage Preparedness, Status of the Electric Grid in Massachusetts, March 2004. The findings and recommendations were compiled by the Natural Gas Working Group.

ensure that the necessary levels of gas supply and transportation are held by power generators, while adhering to market principles."

New York

Currently, natural gas makes up over 25 percent of electricity generation in New York. About 90 percent of New York City's generation uses natural gas either as a primary or secondary fuel. Natural gas is mostly used as a winter peaking fuel for electric generation in the state. The vast majority of new generating units being constructed and proposed are gas-fired with limited dual-fuel capability.[26] During the winter of 2002-2003, in addition to significant gas price volatility, there were several instances where generators were unable to receive gas – over 800 hours between January and April 2002 with increased incidence of unit deratings.[27] The market monitoring unit of the New York ISO reported that even though gas-fired generating units were not able to get fuel at critical times there was no loss of load on the electric power system.[28] The report acknowledged the possibility of gas-delivery shortfalls causing the loss of electric load. It also identified two options that the ISO may want to consider: (1) the requirement that generators procure firm service for some or all of their gas requirements and (2) the implementation of more stringent rules to ensure adequate dual-fuel capability on gas-fired units. The report predicted that natural gas prices in the state would be driven up if generators attempted to procure firm transportation service.

The New York ISO has expressed concern about interruptible service to electric generators jeopardizing the reliability of the state's electric power system. In addition, as in New England, the ISO has questioned whether adequate gas pipeline capacity exists to satisfy the demands of both electric generators and traditional gas utility

[26] During a Jan. 23, 2001 FERC Technical Conference, Jeffrey Gerber of the New York State Energy Research and Development Authority made the observation that developing a balanced portfolio of generating units involves not only "considerations of base-load, intermediate and peaking duty, but also to hedge the risk of overdependence on any particular fuel."

[27] In a press release of Mar. 27, 2002, the New York ISO emphasized the need for the state to "examine the expansion of its natural gas transmission infrastructure to facilitate the development of additional natural gas-fired combined cycle plants."

[28] Market Monitoring Program, "NYISO MMP Report on Natural Gas," presented to the New York ISO Operating Committee, June 11, 2003.

requirements with firm supply during the winter months. Finally, the ISO has expressed concern over the absence of dual-fuel capability for most new power facilities.

The New York ISO along with the New York State Energy Research and Development Authority funded a study, conducted by Charles River Associates in 2002, to examine the impact of increased demand for natural gas by electric generators on the state's electric power and gas pipeline infrastructures.[29] The study applied an integrated model of the electricity and natural gas infrastructures for the Northeast. The study made several key findings and conclusions. The first was that it continues to be critical for generators to have the ability to burn oil even when gas supplies are adequate; oil storage should also be preserved to assure future reliability of the electrical system when gas cannot be delivered. The report projected that the expected additions to gas pipeline capacity should be adequate to meet the demands for gas by electric generators, provided the existing ability to burn oil is maintained. Second, the study concluded that the gas available for electric generation declines dramatically when cold weather reaches design winter conditions (that is, 10-15 percent colder-than-normal winter temperatures). Third, the incremental gas usage from new combined cycle facilities may not be as great as expected when taking into account the retirement or decreased use of less energy efficient, existing gas-fired units.[30] Fourth, gas pipeline capacity, local fuel storage, and dual-fuel facilities are substitutable in achieving adequate electric-system reliability. Finally, electric generators lack economic incentives to procure firm gas transportation. As discussed above, as long as electric generators are able to purchase low-cost interruptible service during high profit-margin periods, namely, periods of a high spark spread, which typically are during the summer months when pipeline capacity is abundant, they will be content to continue to do so.[31] The report proposed that the incentives of gas pipelines and electric generators be

[29] Charles River Associates, The Ability to Meet Future Gas Demands from Electricity Generation in New York State, Final Report, prepared for the New York State Energy Research and Development Authority and the New York Independent System Operator, July 2002.

[30] The older gas-fired power plants are either steam generators or combustion turbines. Steam generators have much higher heat rates than new combined cycle gas turbines – in some cases almost 50 percent higher. Most of them, however, have the ability to burn residual oil, which is lower priced than distillate oil which, in turn, is typically the switching fuel for newer vintage gas-fired plants.

[31] This assumes that they are rarely if ever interrupted. If summer gas pipeline capacity starts to get tight, with the occurrence of interruptions, electricity generators may contemplate purchasing more firm service.

"better aligned" to improve electric system reliability and efficiency. Of course, how this would be accomplished poses a serious challenge for FERC as well as for regional electric power operators/planners.

PJM Interconnection, L.L.C.

Currently, gas-fired generation accounts for about 20 percent of total electric generation in PJM's operating area. Gas is the marginal fuel during the summer months and has become a greater part of base load, mostly displacing coal-fired generation. As in other regions of the country, there has been concern about the adequacy of pipeline capacity to meet future requirements. A study funded by PJM, NERC and the other Northeast ISOs ("The Multi-Region Natural Gas Infrastructure Study")[32] projected that gas pipeline capacity in its area should be adequate to meet the growth in electric generation through the winter of 2006-2007; minor problems in gas deliverability may be expected starting in the winter of 2007-2008. The study identified three options to mitigate electricity interruptions from gas-delivery bottlenecks: (1) demand-side management activities, (2) higher dual-fuel plant capability and (3) firm gas contracts. The study noted that the minor shortfalls expected in 2007-2008 could be averted by the availability of back-up fuel at gas-fired generating facilities. PJM is currently studying these options for possible implementation. PJM is also reassessing the "randomness" aspect of in reliability calculations. Like others, the multi-region study emphasized the importance of cooperation between electric system operators and gas pipelines, back-up fuel supplies and switching capabilities, and of additional knowledge by electric system operators of gas transportation arrangements.

California

Since 2000, California has investigated the effect of increased dependence on natural gas for electric generation. A RAND study conducted in 2002 reported that the current pipeline infrastructure in California and other western states is operating close to

[32] See, for example, Ken Mancini, "Multi-Region Gas Infrastructure Study," presentation to the NERC Gas/Electricity Interdependency Task Force, Houston, Texas, May 15, 2003; and PJM, "Summary of Results: Multi-Region Natural Gas Infrastructure Study," RAA-RC Meeting, Wilmington, Delaware, Sept. 25, 2003.

capacity and that plans for interstate pipeline expansion may lag behind projected demand growth.[33] The study also pointed out that the growing summer peak in gas consumption for electric generation has placed stress on the management of storage since injections to storage will need to occur over a shorter period of time. Strong demand growth for electric generation could also strain the gas transmission and distribution infrastructure, which could jeopardize gas service to all customers. The study recommended that California begin to address potential infrastructure shortfalls by looking at increasing receipt capacity, building new pipelines, increasing the capacity of existing pipelines and studying the viability of increasing storage capacity. Particularly serious is the inadequacy of intrastate capacity, which makes it more difficult for the gas transmission system to deal with disturbances and sudden surges in load. Overall, the system has become susceptible to price volatility and curtailments.

The California Energy Commission has also studied the problem of possible shortfalls in intrastate pipeline capacity.[34] Specifically, it identified the major problem as planning for summer peak demands in view of the growing demand by gas-fired generators. In a 2001 report, the Commission recommended new design criteria and reliability standards for the state's natural gas system largely because of the significant growth in gas consumption by electric generators.[35] The report argued that current design criteria are no longer relevant because of the erosion of fuel switching capability by gas-fired facilities. It advocated an integrated planning function for the state's gas pipeline and storage facilities to identify needed additions in response to future demand. The report concluded that the high gas prices in California in 2000 and early 2001 were partially the result of inadequate capacity to receive gas at the California border. Finally, the report identified the challenge facing decision-makers in choosing between serving electric generators during the summer months and storing sufficient gas for winter use.

---

[33] Mark A. Bernstein et al., Implications and Policy Options of California's Reliance on Natural Gas, RAND Science and Technology Report, 2002.
[34] California Energy Commission, Natural Gas Infrastructure Issues, October 2001.
[35] Ibid.

NERC

NERC has recognized the potential negative impact of gas-fired facilities on electric system reliability. In its *Reliability Assessment 2003-2012* report, NERC devoted significant attention to this issue.[36] The report provided statistics on the significant increase in market share of gas for electric generation in most regions of the country. Building of new gas-fired power plants was on an upward trend from 1998 through most of 2001, after which there has been a somewhat downward trend in new gas-fired capacity. As mentioned above, NERC projections call for capacity fired by gas to represent over 38 percent of total electric generating capacity in the United States for the summer of 2008; in comparison, capacity fired by gas was 23 percent of total electric generation capacity in 1998.

While the growth in gas usage has reduced fuel diversity in electric generation in some regions, it has increased it in others. The report stated that "fuel deliverability is a concern relative to the operating reliability [security] of the infrastructure that delivers natural gas to the generating stations. In some areas, deliverability to the generation is limited." NERC recognized that the operating reliability of the gas infrastructure should be factored into overall operational and planning reliability. In *Reliability Assessment 2002-2011*, NERC also noted that:

> Reliability standards for the interconnected electrical transmission systems dictate that they are planned to reliably operate through first contingency electrical failures…The lack of similar standards [for the natural gas industry] makes it difficult to assess the adequacy of the pipeline infrastructure under single pipeline contingencies. In some areas…a single gas system disturbance may result in the eventual loss of more electrical generation than traditional analysis would indicate for a similar electrical disturbance. Additionally, upon the sudden loss of electrical generating units, gas delivery limitations may prohibit gas-fired generators that remain on line from fully responding to the sudden loss unless adequate measures are taken prior to the occurrence.[37]

---

[36] North American Electric Reliability Council, Reliability Assessment 2003-2012, December 2003.
[37] North American Electric Reliability Council, Reliability Assessment 2002-2011, December 2002, 23. The report discussed other potential problems, including the lack of an outside independent review of the reliability of the gas pipeline system or of its capability to deliver natural gas at the pressures required by new electric generating facilities.

The 2003 *Reliability Assessment* report identified specific problems in individual regions. Examples of these are presented below:

- For the Electric Reliability of Texas (ERCOT), an emerging problem relates to the concern about "the availability of natural gas during the winter peak given the fact that over 60 percent of existing and projected total generating capacity in ERCOT is fueled solely by natural gas." In late February 2003, several gas-fired generators were curtailed in the region during several days of extreme weather. This emergency incident triggered ERCOT to study whether to provide incentives to generators to install dual-fuel capability and to change the gas-supply curtailment priority of electric generation.
- Last year the Florida Reliability Coordinating Council formed a natural gas/electricity interdependency task force to assess and monitor the risk of increased reliance on gas for electric generation. In Florida, several older generating units are being repowered at increased capacity with combined cycle technology burning gas.[38]
- The Mid-American Interconnected Network, Inc. expressed some concern over the reliability effects of increased dependence on natural gas for electric generation.
- The Southeastern Electric Reliability Council projects that planned increases in gas-fired generation will require significant expansion of the gas-transportation infrastructure.

As mentioned above, NERC has formed a GEITF to examine how gas pipeline operation and planning affects electric system reliability. Specifically, the task force highlighted the importance of the operating reliability of the gas pipeline network as a determinate of overall electric power operational/planning reliability. The task force has made several preliminary recommendations.[39] They include the following:[40]

[38] Repowering in the form of coal-to-gas conversions will allow utilities to comply with environmental regulations because of the combination of fuel-switching and heat rate improvement.
[39] The task force reports to the NERC Planning Committee.
[40] Most of the information presented here is taken from the minutes of meetings conducted by the GEITF, with the latest minutes from the meeting of Sept. 11, 2003.

- Review of the regional gas supply and transportation situation as an essential component of NERC's annual reliability assessments. This will also involve developing standards for resources to qualify as part of the reserve margin. This raises the question of whether gas-fired generators in a region with tight gas-pipeline capacity would satisfy the standards.
- Coordination of the gas/electric system operators regarding maintenance schedules and outages. Coordination and cooperation between electric power system and gas pipeline operators are vital to maintain reliable electric service.
- Development of an interindustry strategy in part to establish an emergency communication protocol between security coordinators and gas-pipeline operators.
- Establishment of a monitoring system to report gas/electric incidents that have reliability impacts. These may include gas pipeline constraints that reduce pressures below acceptable levels. Gas system pressure is analogous to voltage on an electrical system. Pressure reductions in a power plant lower gas temperatures causing condensation. New gas-fired facilities are particularly sensitive to consistent fuel quality, and they require high gas pressure.
- Facilitation of interindustry data-sharing, reports and reliability studies. Of course, the confidentiality of information would become a thorny issue that may be difficult to resolve.
- Review of state and federal gas curtailment policies and emergency tariffs. Incidentally, the NARUC Ad Hoc Staff Subcommittee on Critical Infrastructure is currently surveying states on their existing curtailment rules and policies. The results of that survey should be publicly available later this year.
- Inclusion of gas-pipeline contingencies in the list of considerations included in NERC's planning criteria. The task force raised the concern that gas pipelines generally operate independently of each other and have less redundancy than electric power systems.

NAESB

The NAESB has recently formed a gas/electric coordination task force to "[review and investigate] possible standards creation and revisions of existing standards related to additional coordination of the interaction between the scheduling of electric and gas transactions." NAESB functions as an industry group that develops standards to promote a seamless marketplace for wholesale and retail natural gas and electricity.

In a preliminary issues list, the task force recommended coordinating with the NERC GEITF to "ensure that both groups are informed as to the other's progress and goals."[41] In the months ahead, the task force will be addressing a wide range of topics dealing with electricity/gas interdependency. One of these includes discussing "the need for increased and/or more formal communication protocols between natural gas and power operations/control room personnel."

Other Studies and Activities

Other groups have addressed the connection between electricity and natural gas markets. The recent National Petroleum Council (NPC) study has emphasized the importance of fuel switching by power plants and adequate gas transportation capacity in reducing the volatility and level of natural gas prices: [42]

> [P]ower producers, especially those that provide peaking service, are reluctant to contract for firm pipeline service because charges for firm service cannot be economically justified in power sales. The result is that regulatory barriers may be inhibiting efficient markets and discouraging the financial incentives to develop and maintain pipeline infrastructure.[43]

The study noted the dramatic growth of gas-fired generation, most of which lack the ability to burn an alternative fuel. The study emphasized the important role that state public utility commissions can play in expanding the capability of power plants to switch to alternative fuels. Specifically, commissions can (1) ensure

---

[41] North American Energy Standards Board, "Preliminary GECTF Issues List as Developed at Jan. 29th-30th Meeting," February 2004.
[42] National Petroleum Council, Balancing Natural Gas Policy – Fueling the Demands of a Growing Economy, Volume I, Summary of Findings and Recommendations, September 2003.
[43] Ibid., 47.

alternative fuel consideration in the integrated resource planning process, (2) allow recovery of switching costs, (3) support fuel backup capability and (4) incorporate fuel-switching considerations in power market structures.

The NPC study projects a significant price effect from increased fuel-switching capability for the industrial/electric generation sector. Specifically, it projects that an increase in the switching capability of industrial boilers from the 2003 level of about five percent to 28 percent by 2025, with the added assumption that fuel backup would be included in 25 percent of new gas-fired generation, would reduce the average wholesale price of natural gas by over $1 per MMBtu (in 2002 dollars) during the period 2011-2025.[44]

In a recent statement before the U.S. House of Representatives, EEI argued that “Congress and the President [should] make sure that federal policies assure that an adequate and diverse fuel supply is available for the generation of electricity.”[45] The statement defined fuel diversity to include fuel-switching or dual fuel capability where “natural gas-fired plants are constructed and permitted to allow a switch between natural gas and oil products in times of either high prices or limited natural gas supplies.” EEI identified three major barriers to fuel-switching by new gas-fired power plants: (1) environmental resistance to oil firing, (2) local opposition to oil storage at generating sites and (3) economic and financial resistance to increased capital requirements to dual fuel.[46] EEI has urged pipelines to offer flexible tariffs to accommodate the special requirements of power plants. During the past several years, electric generators have petitioned pipelines to offer new delivery services so that gas-fired power plants could take hourly deliveries of gas on short notice to provide adequate electricity supplies during periods of high demand. EEI has also advocated pipelines offering firm tariff service allowing power generators and power marketers to receive on a timely basis all the natural gas they require. Over the last several years, gas pipelines have shortened contract terms and increased the flexibility of scheduling

---

[44] National Petroleum Council, Balancing Natural Gas Policy – Fueling the Demands of a Growing Economy, Volume II, Integrated Report, September 2003, Chapter 1, 17.
[45] Edison Electric Institute, Statement by the Edison Electric Institute, before the U.S. House Committee on Energy and Commerce, June 10, 2003.
[46] Chuck Linderman, presentation at the 35th Annual Regulatory Policy Conference, Institute of Public Utilities, Charleston, South Carolina, Dec. 9, 2003.

practices to capture opportunities for expanded sales to the electric generation sector. In many instances, the inherent nature of electric generation requires frequent and rapid changes in gas flow from the pipeline system.

The American Gas Association (AGA) has expressed concern over the possibility that the offering of new gas pipeline services to electric generators may jeopardize service reliability and flexibility to traditional firm gas customers. AGA pointed out that the requirements to serve electric generators place special demands on gas pipelines when compared with the demands of gas utilities and other firm shippers.[47] Most recently, AGA has endorsed during emergency situations "easing environmental restrictions on a temporary basis so that electric generating facilities and industrial facilities can switch to alternative fuels."[48]

A recent Electric Power Research Institute (EPRI) report concluded that while new gas-fired generating capacity "bring greater efficiency, the exit of dual-fuel generating units leads to a loss in fuel flexibility, greater natural gas price volatility, and less reliability of natural gas-fired generation.[49] The report underscored the importance of power generators to ensure reliability of gas supplies in view of the lack of capability for most new gas-fired generators to switch fuel. The report provided evidence of significant cost savings for generators who maintain dual-fuel capability. In view of the deficiency of dual-fuel alternatives, gas storage was identified as an important factor in maintaining the reliability of new gas-fired facilities. In an earlier report that took a detailed regional approach, the EPRI report noted that "the power industry in several

---

[47] See, for example, Leo Cody, Statement…before the Staff Technical Conference on Natural Gas Transportation Policies and Competitive Natural Gas Markets, FERC Docket No. PL00-1-000. Three major operational issues regarding gas transportation to electric generators include: (1) pressure fluctuations, (2) hourly flexibility and (3) "line pack" recovery. The last refers to the amount of gas that is available in a pipeline as a result of above-normal pressure in the pipe. Line packing can provide significant storage capability, allowing a power plant to operate long enough for the electric system operator to take action in the event of a gas curtailment elsewhere on a gas delivery system.

[48] American Gas Association, Statement on Energy Information Administration Annual Energy Outlook 2004 Forecast, before the U.S. Senate Energy and Natural Resources Committee, Mar. 4, 2004, 6.

[49] Electric Power Research Institute, Impact of Natural Gas Market Conditions on Fuel Flexibility Needs for Existing and New Power Generation, January 2002.

areas will likely be required to shift from interruptible to firm rates in order for pipeline developments to proceed."[50]

FERC has also expressed its concern over the increased interdependency between natural gas and electricity. A 2003 presentation by the Office of Market Oversight and Investigations highlighted the decreased flexibility of the natural gas system to respond in the winter months to abnormal situations because of the growth of gas-fired generation, especially for base load use.[51] It questioned the accuracy of estimates that 30 percent of gas-fired plant capacity has dual-fuel capability in view of environmental restrictions, warranty restrictions on switching to another fuel in new turbines, and access restrictions to another fuel.

Since 2002 the FERC has held regional conferences on the adequacy of the country's electric, natural gas and other energy infrastructure. Regarding the use of natural gas by electric generators, brief examples of the information are listed below:

- In the Southeast, almost all new generating capacity is gas-fired. Regional gas pipeline expansions are being built to serve new gas-fired generating units.
- In the Midwest, gas pipeline construction is being built to serve electric generators.
- In New England, adequate electricity generation exists to meet peak demand even with the loss of generation from single-fuel, gas-fired power plants with interruptible transportation contracts. Little redundancy in the regional gas pipeline system makes it vulnerable to component failure.

A recent study by the Energy Modeling Forum (EMF) emphasized the importance of fuel-switching by electric generators and other users of natural gas.[52] Specifically, it noted that "If technology and policy allow energy-consuming groups considerable

---

[50] Electric Power Research Institute, The Regional Gas Infrastructure – Is It Ready for the Power Boom?: How Changes in Gas and Electric Industries Affect Reliability and Competitiveness of Gas-Fired Generation, January 2001.
[51] Federal Energy Regulatory Commission, Office of Market Oversight and Investigations, untitled presentation, Nov. 13, 2003.
[52] Energy Modeling Forum, Natural Gas, Fuel Diversity and North American Energy Markets, EMF Report, September 2003.

flexibility in curtailing their use of natural gas as prices rise, the balance between natural gas supplies and demands can be restored with smaller increases in the price of natural gas."[53] The study recognized the decline in fuel-switching capability of gas-fired power plants over time, but makes the observation that "customers could return to this option if they feared volatile prices and if environmental controls allowed them the flexibility."

Another EMF study identified two kinds of fuel-switching by generating units:[54] (1) direct fuel-switching between natural gas and oil and (2) indirect switching between natural gas and coal. Within each of these categories, switching does not always occur because of price. Some dual-fuel units switch fuels for non-price reasons. For example, infrastructure or contractual constraints, such as pipeline bottlenecks, may cause these units to annually switch from natural gas to oil during the winter months. The study analyzed 597 generating units advertised to have dual-fuel capability during 2000-2001, a period over which natural gas prices were higher than oil prices for some of the time and lower for other times. The following evidence was highlighted: (1) about one third of the units actually engaged in fuel-switching, largely by switching to a fuel with the lower price, (2) 27 units switched from natural gas even though its price was more favorable – this was referred to as direct seasonal switching, where non-price factors triggered the switching and (3) seasonal indirect switching (for example, switching from gas to coal because of pipeline capacity constraints) was as important, if not more so, than both seasonal and direct price-sensitive switching. Overall, the study implied that fuel-switching across an electric power system may be robust even with limited dual-fuel capability.

[53] Ibid., 15.
[54] John Pyrdol and Bob Baron, "Fuel Switching Potential of Electric Generators: A Case Study," EMF Working Paper 20.3, July 2003.

POLICY IMPLICATIONS

The various studies and other sources of information addressing the gas/electricity interdependency issue identify potential problems. For the most part, however, they offer no concrete policy initiatives based on well-founded analysis of the associated costs and benefits. One possible exception to this is the widely offered recommendation that electric power and gas pipeline operators should communicate better with each other and, perhaps, even coordinate some of their operational activities. These actions would seem to have potentially higher benefits than the costs required to undertake them. An example where an action may not be cost-beneficial is for an electric power operator to require firm contracts for gas pipeline service to generating units. While this would tend to increase the reliability of electric service, it would also likely drive up the generation costs of gas-fired facilities. The same outcome could result from the electric power operator mandating dual-fuel capability, which would lead to additional capital costs for generators. Policymakers should be wary of such Draconian measures even though they would presumably increase the reliability of electric power systems.

In any attempt to mitigate a potential reliability problem, the benefits and costs should be considered. As a general rule, any action that would increase reliability of an electric power system would also increase costs and the price of electricity. The policymaker must assess the optimal level of reliability, which from an economic perspective is where the marginal benefits of increased reliability equal the marginal costs.

Basically, since the security of an electric power system is the paramount issue at hand, the primary responsibility seems to lie with the system operator. The fact that interruptible gas pipeline contracts and single-fuel, gas-fired power plants may cause lower power system reliability should be accounted for by the system operator. The operator must be able to compile the necessary information, as well as to analyze it, to assess the reliability of the electric power system given a wide array of factors including the deliverability of natural gas to power plants and the ability of individual power plants to switch fuels. In other words, the operator faces the challenge of determining the reliability of gas-fired power plants in terms of their contribution to both electric power system security and adequacy (as defined by NERC). This entails assessing the adequacy of existing and planned gas pipeline capacity to reliably satisfy the coincidental demands of gas utilities, gas marketers and other intermediaries, and electric generators.

As mentioned above, a NERC task force has recommended that reviewing the regional gas supply and transportation situation should be incorporated into NERC's annual reliability assessments. The task force also advocated broadening NERC standards to include gas pipeline contingencies to be part of the NERC planning criteria. Prescriptions from the outside in the form of mandates to require firm gas pipeline contracts and dual-fuel capability could be counterproductive in terms of benefiting electricity consumers.

Policymakers can address the potential problems from gas-electricity interdependency in various ways. Some final thoughts are offered below largely to stimulate a dialogue. These comments reflect the major findings of this study:

1. **Probably least contentious is the need for electric power system and gas pipeline operators to communicate and, if feasible and economical, to coordinate their activities.** Coordination refers to an adjustment by one or more parties so as to have a more desirable outcome. For example, an electric power operator could require a pipeline to change its operations to improve electric reliability or to minimize the possible cost of a contingency. Usually in social situations voluntary cooperation between two or more parties requires that each of them perceives themselves to be better off. It is not clear how a gas pipeline benefits by cooperating with an electric power operator, who would most likely initiate a cooperative arrangement. In any event, coordination between electric power and gas transportation operators may be more difficult to achieve than it appears at first glance.
2. **Promoting new gas-fired plants to have dual-fuel capability should be done with caution.** The general consensus seems to be that additional fuel-switching capability, if done on a large scale, would help to stabilize the price

of natural gas as well as to improve electric reliability. From a societal context, there may be adverse environmental and land-use effects in addition to incremental capital expenses that could drive up the price of electricity. As discussed above, the NPC study recommended that state public utility commissions advance, or at least not stifle, fuel-switch capabilities for new gas-fired power plants. This recommendation, however, failed to account for the economic and environmental/land use costs that would ensue. Evidence points to the common practice of seasonal fuel switching on electric power systems, even if it is not directly between natural gas and oil.

3. **Advocating firm contracts for gas pipeline service to electric generators would have mixed results.** Firm contracts would presumably increase electric reliability, but on the downside it could drive up the price of electricity. In addition, it would likely make less firm service available to other natural gas customers, including households and businesses. It is unknown how much pipeline construction has been adversely affected by the unwillingness of most gas-fired generators to sign firm contracts. As argued earlier, these generators are assumed to act rationally in their decisions to procure interruptible service. If, in the future, pipeline capacity becomes especially tight -- with electric generators being cut off more frequently and for longer periods -- generators may be more willing to purchase firm service. This may be particularly true during the summer months (or off-peak periods) if the availability of interruptible service becomes more limited because of increased use of pipeline capacity for both electric generators and storage by traditional customers, such as local gas distributors. If in fact interruptible or other less-than-firm gas pipeline service is underpriced, then it could be inferred that generators are purchasing too little firm service. As long as the potential costs of interruptible gas pipeline service are fully internalized to electric generators, they should not be required to purchase more firm service. A generator might compensate for interruptible service by purchasing storage capacity. Traditionally, storage is used to balance seasonal demands through injections, storage and withdrawal; this reduces

the need for additional pipeline capacity to meet peak requirements, improves supply reliability, and dampens price spikes that occur in tight supply conditions. The role of storage has evolved over last the few years, becoming more of a marketing service under which many services such as parking, swaps, transportation exchanges and gas loans are offered. These services add flexibility and provide arbitrage opportunities. The regional power operator/planner should make sure that the risk of interruptible contracts is entirely shouldered by the generator. This means that interruptions should result in fewer revenues for electric generators or in penalties imposed upon those generators obligated to provide reserve capacity on the electric power system.

4. **The almost exclusive reliance on new gas-fired generating units since the early 1990s to meet growth in the future demand for electricity may pose a national problem requiring a federal initiative.** Although recently there has been a renewed interest in coal and renewable sources of energy for electric generation,[55] if for no other reason than that natural gas prices have accelerated, natural gas is still by far the primary source of energy for

[55] The Energy Information Administration's (EIA's) latest forecast of natural gas demand for 2025 (the "reference case") is 3.5 Tcf lower than in the previous year partially because of an upward adjustment in the natural-gas price forecast that will cause other fuels to become more competitive for electric generation. See Energy Information Administration, The Annual Energy Outlook 2004 (AEO2004), January 2004. At the request of U.S. Representative Barbara Cubin, Chairman of the Subcommittee on Energy and Mineral Resources, EIA conducted in February of this year an assessment of four low natural-gas supply scenarios. The worst case scenario, which combines the assumptions of no increased availability of Alaskan natural gas, no significant increase in production of nonconventional gas sources, and the inability to permit more than three additional liquefied natural gas off-loading facilities, projected a much lower use of natural gas for electric generation by 2025. Specifically, compared to the EIA's reference case, the worst case scenario projects 3 Tcf lower gas consumption for electric generation in 2025, which represents an almost 36 percent decrease. EIA projects that under the worst case scenario "oil-fired generation increases significantly because dual-fuel units that can burn both oil and gas switch to oil when natural gas prices get sufficiently high." Under the worst case scenario, in 2025 the natural gas share of the electric generation market is 15 percent, which is less than the share in 2002 and substantially less than the 23 percent projected in the reference case. (See Energy Information Administration, Analysis of Restricted Natural Gas Supply Cases, February 2004.)

new generating facilities.[56] Various reasons account for this – some of which make economic sense while others are suspect. For example, if barriers are uneconomically obstructing alternative sources of energy, then it could be argued that, at least from an economic perspective, the United States may be depending excessively on natural gas for future electric generation. Just a short few years ago, industry observers were extolling the large national benefits that would come from increasing the share of natural gas in the United States energy sector. The emphasis most recently has distinctly shifted to stabilizing the future price of natural gas, including looking at approaches to curbing demand such as energy conservation and fuel switching by electric generators and industrial firms. Some interested parties have suggested that the use of natural gas for electric generation should be legally curtailed so as to eliminate the upward pressure on natural gas prices. The presumption is that by having lower gas prices consumers and society as a whole would be better off. The problem with this line of thinking is that higher electricity prices, and possibly an adverse environmental effect, would ensue. As long as the price of natural gas corresponds to its marginal cost, and assuming minimal barriers to alternative electric-generation technologies, artificial restrictions on the use of natural gas for electric generation would be an economically inefficient and ill-advised policy. This would be true notwithstanding the fact that the market price for natural gas would decline.

5. **State public utility commissions and other state agencies may want to revisit the current curtailment plans of local gas distributors.** Many of these plans were developed prior to restructuring of the natural gas industry

[56] As an example, Wisconsin Energy Corporation proposed, and received approval from the Wisconsin Public Service Commission in late 2003, to build two 615-megawatt supercritical pulverized coal units at its Oak Creek site. This will be the first coal plant built in Wisconsin in over twenty years. The company reasoned that because of high gas price volatility and possible pipeline bottlenecks (natural-gas pipeline capacity in southeast Wisconsin is constrained), building a gas-fired plant would be risky. In addition, the company argued that Wisconsin cannot afford natural-gas plants that operate on a regular basis year-round. If the entire facility were gas (which includes an integrated gasification combined cycle unit, which was not approved by the Commission), Wisconsin Energy calculated it would burn as much gas as it takes to heat one million homes in Wisconsin. The entire Wisconsin Energy system currently serves 900,000 residential customers. The company is also not convinced that the United States has sufficient resources to support demand for gas over the next 20 years.

over the last several years and the growth of natural gas use for electric generation. State public utility commissions in particular may want to inquire whether existing curtailment policies take into account a natural gas industry where: (1) more customers, including households in several states, have choices of gas suppliers, (2) natural gas has become a more critical source of fuel in the generation of electricity, (3) infrastructure security threats have proliferated, (4) FERC's policy on interstate pipeline curtailments has changed, essentially starting with Order 636[57] and (5) regional pipeline bottlenecks have periodically been a serious problem. At the least, state commissions may want to revisit the curtailment policies of local gas distributors in view of these developments. Many commissions have probably done so, while others have not.

[57] The end-use curtailment policies of the 1970s, which defined boiler fuel gas as the lowest of firm priority-of-service categories, do not apply to modern capacity curtailments. Presently, as discussed earlier, any curtailments due to capacity constraints generally develop on how contract rights are specified for individual transportation customers.

SUMMARY

The increased dependency on natural gas for electric generation has posed serious challenges for both the electric and natural gas sectors. This paper surveyed those studies and activities that mainly addressed the issue of whether the reliability of regional electric power systems will be compromised because of the dramatic shift since the early 1990s toward natural gas for fueling new electric capacity. One area of agreement among stakeholders and other industry observers is that, at the minimum, dialogue between the natural gas and electric sectors will be vital to assure reliable electric service.

Economic factors as well as environmental/land use constraints have caused many power generators in recent years to select nonfirm gas pipeline service and single-fuel capability. What effects these decisions will have on electric-service reliability has been assessed by different industry groups. The evidence compiled thus far indicates that a potential problem might be looming if certain initiatives are not taken. These include expanding gas pipeline capacity to accommodate new power generators, lifting existing restrictions of various sources on installing and operating dual-fuel generating plants, and diversifying more the fuel portfolio of new generating facilities. Different regulatory and other governmental agencies at all levels will need to be involved in taking action if found to be warranted.

The robust dialogue that is ongoing in addressing the gas/electric interdependency issue is certainly encouraging. But to reach agreement on what policy actions should be taken may require government leadership as well as proactive actions by regional electric power operators.