The Role of Natural Gas in the Northwest’s Electric Power Supply

August 2012

Summary
Northwest energy providers have a growing interest in understanding the role of natural gas in the region’s electricity supply. While there is nothing new about gas-fueled electricity generation, it has not been a large part of the supply picture in the hydro-rich Northwest. But there are clear indications that picture is changing. A number of sources, ranging from individual utility resource plans to the Council’s Sixth Power Plan, point to an emerging emphasis on natural gas as the fuel of choice to generate electricity to meet future needs.

This paper provides an overview of the shift toward natural-gas fired generation and the issues it raises for the region’s electricity and gas industries, as well as regulators and policymakers. The information comes from references listed at the end of the paper, as well as from presentations and speakers at a Northwest electricity and natural gas summit held in early 2012. A recurring question at the summit was whether the Northwest’s current natural gas infrastructure can accommodate a large-scale shift to gas-fueled electricity generation. A representative of the Northwest Gas Association (NWGA) said electricity generation is “the wild card” in the mix for natural gas supplies in the Northwest.

The Northwest’s gas infrastructure currently serves the needs of the region. But it was not built to serve a large-scale generation market and currently operates at 100 percent of capacity during extreme cold-weather peak periods in the winter. At other times of the year, the pipeline system operates at a relatively low load factor, affording significant flexibility. Without infrastructure additions, however, there is no excess capability to serve large new markets on a year-round firm basis. Utility CEOs, planners, and regulators emphasized the need for the two industries to coordinate their plans, infrastructure, and operations to prepare for a future in which gas is a key component of the Northwest’s electricity supply.
Background on the Electricity/Gas Convergence

The Northwest, including western Canada, is served by five interstate/provincial pipelines and six natural gas distribution companies that operate and maintain about 48,000 miles of transmission and distribution pipelines. There are also a number of natural gas and liquid natural gas storage facilities in the Northwest, which are shown in Figure 1.

According to Allison Bridges of Williams Northwest Pipeline, who spoke at the 2012 summit, the combined system shown in Figure 1 can deliver 6.5 MMDth/d (million dekatherms per day) to the Northwest on a peak day.

Williams Northwest Pipeline, represented by the red line in Figure 1, serves the major population centers in the Northwest along the I-5 corridor, as well as east of the Cascade Mountains into Idaho. Williams Northwest peaks at 3.7 MMDth/d and has 14 MMDth of storage capacity. The pipeline has access to both domestic and Canadian gas supplies.

Figure 1: Pacific Northwest Storage Facilities

The Northwest now has about 8,400 megawatts (MW) of installed natural-gas fired generating capacity, approximately two-thirds of which is on the Williams Northwest system. Williams Northwest currently serves 24 gas-fired plants in the region that represent a combined capacity of 5,000 MW of electricity generation. About 2,800 MW of that gas-fired generation has been added since 2002.
Today, gas-fired generation in the Northwest is operated to provide electricity to meet base load, peaking, and reserve demands. During the winter months, the use of natural-gas fired generation to meet base load is at its highest. In the late spring and early summer, during the hydro runoff, natural-gas generation falls off markedly, but it picks up again in late summer when it is needed to meet air conditioning load.

All of the region’s gas generators dispatch their resources based on electricity prices. Many also operate as peaking plants when needed, varying their output greatly on an hourly basis depending on the generation required to meet peak loads.

Figure 2 provides a view of gas use in the Northwest by customer sector. The use of gas for generation has obviously grown while industrial use has declined. As a result, the combined amount of natural gas used for power generation, industrial, and residential purposes in the Northwest is relatively equal today. While electricity consumption overall has trended downward slightly in recent years, the proportion of electricity generation supplied by natural gas has increased.

**Figure 2: Pacific NW Gas Deliveries by Industry**

![Bar Graph: Pacific NW Gas Deliveries by Industry](source: US EIA, StatCan)
U.S. Gas Consumption on the Rise

The Energy Information Administration (EIA) expects U.S. gas consumption to increase by 10 percent between 2010 and 2035. The following graph shows energy consumption by fuel, with gas and renewables on the rise and oil on the decline.

Figure 3: Pacific NW Electric Generation by Fuel

Hydro provides the largest share of the electric power in the Northwest, with coal and the region’s only nuclear plant providing much of the rest. The use of natural gas for electricity generation, however, has grown significantly over the last 15 years, as indicated in Figure 3.

According to PNUCC’s Northwest Regional Forecast (NRF), electricity loads in the region are expected to grow by about 150 to 200 average MW (aMW) annually over the next decade. The NRF indicates utilities in the Northwest have plans to add significant new resources, including another 2,300 MW of natural gas-fired generation over the next 10 years, most of which is intended for peak-demand situations.

The Northwest Power and Conservation Council’s Sixth Power Plans puts the growth rate for electricity demand at between 0.8 percent and 1.8 percent.
annually over the next 20 years. That’s somewhat higher than the EIA estimate of 0.6 percent for the nation as a whole. Figure 4, which came from the Sixth Power Plan, illustrates the range of forecast growth across a high, medium, and low case, as well as a historical perspective on load growth in the region.

The Council’s action plan emphasizes the use of energy efficiency first to meet load growth. It points to wind power as the most readily available and cost-effective renewable resource. But the plan also states that the remaining needs for new energy and capacity should be based on natural gas-fired generation “until more attractive technologies become available.”

There is no additional coal-fired generation in the Council’s plan, and the Council states that in order to reduce carbon emissions in the region, there must be less reliance on the region’s existing coal generation.

**Figure 4: Sixth Northwest Power Plan Power Demand Forecast (MWa)**

In the U.S. as a whole, EIA reports: *Residential* gas demand currently accounts for 20.5 percent of gas consumption. That figure is projected to remain flat between 2012 and 2035.

*Commercial* gas demand currently accounts for 13.3 percent of gas consumption, projected to increase 11 percent by 2035.

*Industrial* gas demand currently accounts for 27.4 percent of gas consumption, projected to increase by 6 percent by 2035. According to the EIA, many energy-intensive industries are declining, but non-energy intensive industries are growing.

Electric generation gas demand currently accounts for 30.6 percent of gas consumption, projected to increase 21 percent by 2035. The proportion of all gas being consumed by the electric sector will rise from 30.6 percent to 33.7 percent, an annual increase of 0.8 percent.
The evolution to natural gas for generating electricity in the Northwest has occurred for a number of reasons. Like elsewhere in the country, natural gas plants have lower construction costs and shorter lead times compared with other alternatives. Natural gas also offers high generation efficiency, lower carbon content than other fossil fuels, and operational flexibility.

Environmental restrictions and the political landscape have cast doubt that any new large hydro, coal, or oil-fired plants will be built in the near future. The PNUCC forecast indicates there are no plans in the next 10 years for additional coal or large hydro plants in the Northwest. In fact, the region's coal plants are being phased out, and the assumption is that most of that generation will be replaced with natural gas. Similarly, while several new or expanded nuclear plants are being pursued elsewhere, notably in the southeastern United States, there is no expectation of new nuclear generation in the Northwest.

There are also plans to add to the already significant growth in wind power. Wind is considered the most available and cost-effective resource to meet state resource portfolio standards in the Northwest, but it poses challenges in terms of power system operations. The biggest challenge is its variability. Although some amount of variability can be accurately forecast, there are inevitably differences between the amount of generation wind plants are scheduled to produce and what they actually deliver. System operators must, therefore, have access to resources to firm up the growing amount of variable generation that is coming onto the system in the Northwest.

Wind Resources Continue to Grow

The expansion of wind power has exploded in the last 10 years, both nationally and in the Northwest. This figure illustrates the significant and rapid growth in the nation’s wind resource, growth that is expected to continue as more states adopt and strengthen renewable portfolio standards.

Wind energy poses a challenge to the power system due to its variability and to the seasonal and daily shape of production. The wind does not necessarily blow at times of peak electricity demand or shut down when demand is slack. In the Northwest, the opposite tends to be true. The wind blows at times when loads are low, and is still when loads are at their peak. The heat maps below illustrate this phenomenon.

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The map on the left depicts the shape of BPA’s electricity load taken at five-minute intervals and averaged. BPA’s load is greatest from January through April, drops during the summer, and picks up again in late November and December. The map on the right illustrates the shape of the region’s wind generation. Wind generation is low during the winter and highest during the spring and summer. In other words, wind generation in the Northwest tracks poorly with BPA’s seasonal load.

The same is true for the daily load shape. BPA’s electricity demand is low in the hours from midnight to 5 a.m. and builds as the day begins, peaking at around 8 a.m. Load peaks again in the evening between 6 p.m. and 8 p.m. Wind generation tends to peak before 8 a.m. and picks up in the evening, producing the most electricity overnight when demand is low.
The Outlook for Gas Generation in the Northwest

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Right now, the Northwest balances most of the variability in wind generation with hydro. There is, however, a limit to the amount of hydro capacity that can be dedicated to balance wind. At some point given the planned expansion of the Northwest wind fleet, the region will run short of balancing capability relying primarily on hydro. Recent experiences, which have included requests for wind generators to lower their output, demonstrate that the limit appears to have been reached.

Energy consultant ICF International predicts an additional 2,500 MW of gas-turbine capacity will be needed by 2025 to firm wind generation in the Northwest and that nearly 6 percent of the region’s total natural gas demand will be for that purpose. Other areas of the country are also expected to experience this disproportionately large influence on the gas infrastructure for firming wind generation. In addition to overall variability, firming wind energy poses other issues. The gas demand for a conventional natural gas-fired generating plant follows the shape of the electricity load. But the demand for a wind-firming plant is much more volatile.

While natural gas is the likely incremental balancing resource, it isn’t clear the region’s existing gas infrastructure is up to the task. Today, this is primarily a concern during peak winter periods, but it could become an issue in other periods, if demand continues to grow as projected. There is also a major question about who will pay for the necessary infrastructure expansions.

As presenters at the 2012 summit indicated, the question is not whether there is enough gas for the job, it is whether the infrastructure can deliver large quantities of gas to specific generators on short notice to make up for the variability of wind. Wind doesn’t necessarily
create more demand for gas – it may in fact have a tendency to reduce annual base load demand – but it changes the way the gas infrastructure will be called upon to meet the region’s needs.

Simply put, generators need to have access to the appropriate gas resources to meet their system demands. This is one of several issues raised by the planned increase in natural gas-fired generation in the region in order to integrate and firm up renewable intermittent resources.

Growing Interdependence of Gas and Electricity in the Northwest

Like any major change in the energy supply, the planned expansion of natural gas-fired electricity generation raises a host of questions, from the adequacy of infrastructure to the lack of symmetry between the everyday operations of two distinct industries. Many of these questions were raised and addressed at the 2012 electricity and natural gas summit. They are not unique to the Northwest, but have lurked below the radar because of the traditionally small amount of natural gas-fired generation in the region.

Infrastructure

Most of the natural gas pipeline network in the United States is a “spaghetti bowl” of interconnected lines. But the Northwest, excluding western Canada, has only two major pipelines. Gas on TransCanada GTN is primarily sourced from Alberta but can also receive gas from the U.S. Rocky Mountains at its terminus at Malin, Oregon, near the California-Oregon border. Williams Northwest Pipeline was designed as a bidirectional pipeline with gas sources at both ends and in the middle of its system, receiving gas from British Columbia, Alberta (via GTN), and the U.S. Rockies.

The gas infrastructure in the region was built to serve entities that subscribed to service, including local distribution companies (LDCs), industrial end-users, and base load power generators. (Peaking facilities in the region have historically relied on oil as a back-up fuel and have not subscribed to firm pipeline service.)

According to the experts, the current infrastructure does not necessarily have incremental firm capacity available in certain areas to serve new generating resources. Nor is the natural gas infrastructure currently adequate to satisfy the significant growth in demand that is projected to be needed to balance regional electricity loads with gas-fired peaking facilities. It is important to note that gas infrastructure is adequate for the resources that are currently in place and reliant on firm gas infrastructure.

Historically, pipeline capacity has been expanded when a customer, such as an LDC, industrial customer, or power generator, requests and commits to a long-term contract for firm capacity. The Federal Energy Regulatory Commission (FERC) regulates capacity expansions and will generally not authorize one unless a customer has already committed to use and pay for it, or if the natural gas pipeline is willing to take on the risk of building or expanding its capacity. Natural gas pipelines in the United States generally are prohibited from passing costs of new capacity on to their other existing customers.

The pipeline network in the I-5 corridor is currently fully subscribed but could be expanded with customer commitment. While
available capacity exists on TransCanada GTN, which runs through eastern Washington and Oregon, there are other issues to consider in siting gas-fired generation east of the Cascade Mountains, including east-to-west electricity transmission constraints.

Figure 5 illustrates the supply/demand balance on the natural gas network. The current natural gas load can be met with pipeline capacity, underground storage, and several existing liquefied natural gas (LNG) plants.

Figure 5: I-5 Total Firm Peak Day Supply/Demand Balance

![Graph showing supply/demand balance](image)

**Storage**

Figure 5 illustrates how heavily the regional gas system relies on storage, primarily at two large facilities, Jackson Prairie and Mist, to meet demand and balance variable supply and demand conditions. LNG storage at six existing plants is also important to meeting peak demand in the region. Overall, the storage facilities in the region are well utilized. They are typically filled in the summer and most heavily withdrawn in the winter, but they provide a balancing function throughout the year.

Peak gas demand is projected to outgrow current supply resources between 2014 (high

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**Expanding Interstate Pipeline Capacity**

The pipeline system in the Northwest has been expanded repeatedly over the years to meet market demand. In order to add new facilities, interstate pipelines like Williams Northwest must first receive a certificate of “public convenience and necessity” from FERC that authorizes construction and operation.

The time required for the FERC review process varies based on the size of the project. Generally, it will take six to 18 months from the time a company submits an application until FERC renders its decision on whether to approve a certificate. FERC authorizes construction to begin when conditions established in its certificate order are satisfied. Typically, major projects take three years to permit and construct.
case) and 2019 (base case), according to the NWGA projections in Figure 5. Either additional pipeline capacity and/or storage will be needed within the next decade to meet the projected growth in the base load.

In addition, the gas storage in the region is concentrated in one area, the I-5 corridor, and some isolated locations on the pipeline network do not have ready access. While storage on the network is currently sufficient to respond to an extreme weather event, such as a prolonged cold snap, the heavy reliance on storage makes it vulnerable if there is a problem at a storage facility.

This was the case at Jackson Prairie in December 2009 when equipment malfunctions and subsequent intermittent production over a period of several hours resulted in low pipeline pressures. The situation led to fuel switching at generating facilities that relied on non-firm resources. In addition, several hundred customers lost service in southwestern Washington during the course of the events.

### Close Call at a NW Storage Facility

On December 9, 2009, during an extreme cold snap in the Northwest, a series of events, including the closure of a valve at the TransCanada GTN-Williams Northwest Pipeline interconnect at Stanfield in eastern Oregon and equipment failures at the Jackson Prairie storage facility, resulted in a gas shortage in the region.

First, in the early morning hours, the Stanfield interconnect between Williams Northwest and TransCanada GTN pipelines closed for three hours due to an insufficient pressure differential between the two pipelines. By itself, this incident would have been insignificant, but it contributed to a situation that escalated throughout the day.

Temperatures at the Jackson Prairie storage facility, operated by Puget Sound Energy, were in the single digits in the morning, and ice formed on individual well water separators. In addition, three flow-measurement meters failed due to high gas volumes. These failures did not impact the gas supply, but they caused problems for operators in responding to subsequent events.

A series of equipment failures ensued, which took time to remedy and disrupted storage withdrawal. In the afternoon, pressure sensors failed due to the cold weather, which caused an emergency shut-down valve to repeatedly close. Storage withdrawal fell to zero on and off for about four hours.

During the incident, a series of communications kept LDCs informed. The LDCs notified interruptible customers to curtail gas usage by switching to alternate fuels or reducing operations, and Puget Sound Energy switched all of its gas-fired generation that has alternate-fuel capability to oil. Pressures on the pipeline got precariously low during the day, but virtually all firm customers were served.

NW Natural, which serves customers in Oregon and southwest Washington, lost service in the early morning to 329 gas customers in Clark County, Washington, and pilots had to be relit. Several hundred more customers, principally interruptible customers, didn’t have enough pressure to run industrial...
equipment. But service to all other LDCs on the pipeline remained intact and gas-fired generators with firm pipeline service remained online.

The pipeline and the LDCs debriefed in the aftermath of the December 9, 2009 events. They determined that communications among the players could have been more robust and carried out earlier, although the extent of the outage was not immediately apparent. But overall, more coordinated regional communications would have helped. All things considered, the system held up well. An outage that affected 25 percent of the peak-day supply for several hours in the I-5 corridor didn’t cripple the system or lead to widespread outages.

As a result of the outage, actions were taken at Jackson Prairie to improve weatherization, educate operators on newer equipment and procedures, and replace a control system. And to get at the communications issues, the pipeline and LDCs revitalized the Northwest Mutual Assistance Agreement to help companies, both gas and electric, coordinate their responses to outages and emergencies.

Unseasonably cold weather led to the December 9, 2009 events. Preparedness for weather, which can be extreme in the Northwest, is another issue for the region to consider in planning for increased natural gas-fired generation.

Susceptibility to Weather

Like many regions of the country, the demand for gas and electricity in the Northwest peaks in the winter when temperatures are at their coldest. Since the region relies on gas-fired generation to meet peaks, cold weather patterns can significantly raise the demand for gas. When an extreme cold weather front rolls through, LDC requirements can double from what’s needed on an average winter day.

The current gas infrastructure in the Northwest has so far been adequate to meet cold weather events, but equipment failure poses a risk. Without proper winterization, generators, compressors, and storage facilities can fail, particularly in areas east of the Cascade Mountains, where temperatures can drop below -20 degrees F.

In February 2011, electricity customers in Texas and the Southwest experienced rolling blackouts caused largely by failure to prepare gas-fired generating facilities for cold weather. In an outage situation that ultimately affected millions of electricity customers, as well as 50,000 gas customers across three states, the industry learned a cold, hard, and costly lesson.

Cold Snap Catches SW Unprepared

The Southwest was experiencing unusually cold and windy weather in the first week of February 2011. It was the worst time for a widespread generation failure. But over a period of four days at least 210 individual generators in the Electric Reliability Council of Texas (ERCOT) area experienced an outage, derating, or failed to start. Utilities were forced to shed load, and at the peak of the rolling blackouts, 1.3 million customers were out of service.

The gas-electricity interdependency in ERCOT is pronounced. Fifty-seven percent of ERCOT’s on-peak generation is gas fired, with 40 percent gas-only and 17 percent dual-
fuel capable. Over 29,729 MW of outages and derates occurred during the first day of the event. There was also generation out due to scheduled maintenance, and together, over 33 percent of all ERCOT generation was unavailable. The freezing weather accounted for 67 percent of the generator failures.

Only 12 percent were due to natural gas curtailment or failure to switch fuels for dual-capability plants. The curtailments that occurred were due to high residential demand and interruptible contracts.

After a similar outage event in 1989, regulators recommended winterization methods for the generators, but the weatherization was not mandatory and for the most part it was not implemented. Many of the same units that failed in 1989 also failed in 2011.

The electricity outages caused gas production outages in two basins because electric pumping units and compressors were shut down. Transmission operators generally did not recognize gas facilities as critical loads during the blackouts. In subsequent reviews, the gas/electricity interdependency was considered a contributing factor but not a significant cause of the outages.

A number of recommendations came about as a result of the four-day event. Among them were pre-event reviews and testing of available reserve and fuel-switching generation, and regulations to exempt critical gas facilities from rolling blackouts. In addition, there was a recommendation that gas providers determine if and when gas customers should receive priority over generators.

Dispatching

There are several issues related to electricity and natural gas dispatching that have been raised as the Northwest looks at its energy future.

**Timing:** While electricity can essentially be delivered in an instant over a power line, gas moves slowly (on the order of 20 mph). Both resources, however, rely on the maximum design of the infrastructure involved. Because of “line pack” and available storage, the natural gas system is resilient to short-term fluctuations between supply and demand that in the electric network might result in blackouts. But limitations with storage and the relative slowness of gas movement mean that extreme prolonged fluctuations could eventually take down portions of a gas network before an influx of new gas supplies can make an impact – such occurrences rarely happen. FERC has ordered and enforces protocols on communication between plant operators and pipelines that must occur if there are any changes that could impact hourly gas flow.

Several speakers at the 2012 summit also took note of the disconnect between the way the electric and gas industries mark time. The gas day begins *nationally* at 9 a.m. Central Time. The electricity day begins at midnight *locally*. Efforts to harmonize the days have been unsuccessful. Such a difference has little impact on prescheduled (or day-ahead scheduled) activity since the magnitude is known and measurable, but it could impact intra-day activity.

**Scheduling:** Gas “nominations” also occur on a different timetable from electric power scheduling. Gas is scheduled four times a day (two times for day ahead and two times intra-day). The majority of all daily gas transactions take place in the day-ahead market – there are very few transactions intra-day.

Electricity is also largely scheduled on a day-ahead basis. Within the operating day, there is a small amount of trading and schedule-change activity but unlike with gas, it can occur hourly and even sub-hourly. There is a trend in
the electric power industry toward increased intra-hour scheduling; in fact, it has been recently ordered by FERC. More intra-day activity for gas-fired generation will likely require additional scheduling flexibilities by pipelines and storage facilities.

Figure 6 depicts the set schedule that is adhered to for gas nominations.

**Figure 6: Gas Nomination Schedule**

<table>
<thead>
<tr>
<th>Nomination</th>
<th>Hour CCT</th>
<th>Day</th>
</tr>
</thead>
<tbody>
<tr>
<td>Timely</td>
<td>11:30 AM</td>
<td>Day PRIOR to gas flow</td>
</tr>
<tr>
<td>Evening</td>
<td>6:00 PM</td>
<td>Day PRIOR to gas flow</td>
</tr>
<tr>
<td>Intraday 1</td>
<td>10:00 AM</td>
<td>Day OF gas flow, effective @ 5 PM</td>
</tr>
<tr>
<td>Intraday 2</td>
<td>5:00 PM</td>
<td>Day OF gas flow, effective @ 9 PM</td>
</tr>
</tbody>
</table>

In addition to the above schedule, the Williams Northwest Pipeline adds an important fifth cycle following the gas flow day, which is used to align after-hours requests.

**Firm Capacity:** All customers who purchase firm capacity are treated equally by the pipeline. Most Northwest natural gas-fired peaking generators do not have firm capacity on the pipeline because they have alternate fuel capabilities and the cost of owning pipeline capacity for a low load-factor (or peaking) facility is very high. The combined-cycle (or base load) gas-fired plants in the Northwest generally have firm capacity on the pipeline while peaking facilities generally rely on interruptible or non-firm pipeline capacity.

In addition, some pipelines are required to enforce “bump” rules that allow firm customers to adjust their nominations in a later cycle and bump interruptible customers. Williams Northwest Pipeline is a “no-bump” pipeline, so firm customers cannot bump interruptible customers on an intra-day basis. In short, these operational priorities pose questions for a region that is planning to become more dependent on natural gas-fired generation.

**Coordination between Industries**

**Resource planning:** In general, utility Integrated Resource Plans (IRPs) are developed with a narrow viewpoint on a local area where customers reside. Utilities in the region are subject to similar political, economic, and environmental constraints surrounding resource development (conservation, demand response, wind, and natural gas) so most IRPs bear similarities. And while the Northwest has a regional power planning body, the Council’s plan does not get into specifics for any particular utility service territory nor does it knit together the electricity and gas industries. There is still a
The current regulatory and planning framework tends to focus on utility-specific solutions and doesn’t easily accommodate coordinated efforts between industries or encourage region-wide long-term planning. There is change, however, under way nationally. The North American Electric Reliability Council’s (NERC’s) Gas/Electric Interdependencies Task Force has made recommendations related to assuring overall resource adequacy and formalizing communications between planning functions in the electricity and natural gas industries.

Daily operations: FERC has enacted regulations proposed by the North American Energy Standards Board (NAESB) that require pipelines to develop communication protocols with power plant operators. Today, gas operators may communicate regularly with personnel at natural gas-fired generators, but they don’t often communicate directly with power dispatchers or system operators. As a general rule, system operators in the electric and gas industries conduct daily operations without direct communication. In fact, it was apparent at the 2012 summit that many in the electric power industry were unaware of the near-crisis in 2009 at Jackson Prairie. NAESB is formulating more standards that would require pipeline communication not only with power plants but also with balancing authorities and regional reliability coordinators.

Emergency response: Industry standards of conduct can get in the way of sharing critical information even during an extreme event.

Gas Supply

There have been no major gas shortages in the Northwest and gas-fired power plants are not experiencing reliability issues. Pipeline and storage capacity in the region are currently sufficient to serve both LDCs and power plants. But the lack of redundancy puts the system at
risk. Component failures, particularly due to cold weather or at a major storage facility, could cause a gas shortage that affects a large area. In the I-5 corridor, Williams Northwest is capable of serving the market with gas from Sumas or with gas flowing west through the Columbia Gorge, which mitigates some of the risk.

In the event of a shortage, who gets priority?

In general, pipelines do not differentiate within classifications of service. Certainly, interruptible customers are interrupted during peak events, but firm customers are cut on a pro rata basis irrespective of customer class in the rare event that gas is not available to serve all firm customers.

LDCs have traditionally focused on “human needs” customers for a couple of reasons. These customers rely on gas for heat, and losing their gas supply can become a question of life and death. In addition, restoring service to these customers once the gas supply fails is an onerous proposition. Residential gas meters are equipped to turn off the gas when pressure in the system drops too low. Once the supply is interrupted, the flow of gas generally cannot be restarted without a technician visiting the home to relight the pilot light. In the aftermath of the Texas and Southwest outage in 2011, for example, it took weeks for local distribution companies to visit homes and relight the pilots for thousands of customers who were without service.

Economics

In any discussion of energy supply and reliability, economics are a major issue. And certainly that is an issue for electric utilities planning to increase their dependence on natural gas-fired generation, from plant construction costs to fuel supplies.

A 2004 National Regulatory Research Institute (NRRI) entitled “Increased Dependence on Natural Gas for Electric Generation: Meeting the Challenge” addressed the economics of ensuring reliability when the power supply depends on natural gas. The report said

In a gas supply shortage, residential users are generally prioritized to stay on while power plants and large industrial customers, which are typically interruptible, tend to be the first customers dropped off the system. Customers in those classifications that have subscribed to firm service, however, are usually not curtailed other than on a pro rata basis. In extreme circumstances, such as the 2011 incident in the southwestern United States, loss of significant supply resources may require different curtailment priorities. It is imperative that such actions be coordinated on a regional level to ensure an optimal solution.

The way service is prioritized can obviously create challenges if natural gas-fired generators elect to rely on non-firm gas for plants that are needed for system reliability. When gas supplies are short, some generators can switch to other fuels, such as oil, diesel, or jet fuel. Most newer gas-fired generators in the Northwest are not dual-fueled, but operators have elected to subscribe to firm natural gas service.

It is also important to note that securing firm natural gas transportation service does not guarantee gas supply to any entity. Each entity must also secure firm supply through purchase contracts or storage in the same way power companies must buy energy as well as transmission. One without the other could result in demand not being met.
regional electric power operators face a potential dilemma in achieving the goals of low wholesale electricity prices and high reliability. Economics factor into decisions by gas-fired generators to purchase non-firm gas transportation service and to forego dual-fuel capability.

FERC also expressed concern in its Order 637 that gas pipeline customers rely too much on short-term service, including interruptible, relative to long-term service. But NRRI points out that requiring gas generators to have firm contracts for gas supply would eliminate some of the threat to reliability, but the costs would be significant and would drive up the price of electricity.

Speakers at the 2012 summit touched on these economic issues. One major money issue is coal-plant closures here and across the country. There is pressure on utilities to close coal-fired plants due to environmental initiatives and a common belief that it will be cheaper for utilities to replace coal with gas-fired generation than comply with EPA rules on emissions. But in reality, the experts say to do that, it will take lots of gas, lots more drilling, lots more coordination, and lots more storage, all of which will pose large economic costs.

**Ensuring Reliability**

In this new resource picture, where gas provides a bigger share of electricity generation, whose job is it to ensure reliability? In the transition to more gas-fired generation, it’s primarily the security of the electric system that is at risk. The power system operator has the responsibility to address day-to-day reliability. But in the big picture, coordination and communication between the industries is required for an orderly transition.

At the 2012 summit, FERC Commissioner Philip Moeller said there are four broad areas in which joint gas and electricity issues need to be resolved: communication; operations and infrastructure; contracting; and planning for contingencies. He sees a role for the commission in shepherding communications between the industries. And while the role for federal regulators and national standards boards are not yet defined, he indicated there will be one. Commissioner Moeller said if the industries don’t tackle and resolve the issues on their own, there will be federal intervention.

BPA Administrator Steve Wright agreed a collaborative Northwest solution would be more palatable than one imposed by federal regulation. In a 2012 letter to Commissioner Moeller, Mr. Wright and representatives of the region’s gas and electricity industry stressed that reliability of the energy delivery system – from pipelines to power lines – is at the heart of the issue.

They urged FERC to recognize ongoing regional collaboration and told Commissioner Moeller that the Northwest has initiated operational and planning dialogues to address reliability and resiliency of both the gas and electricity systems. The NMAA provides a solid foundation for improving communication and coordination among the players and there are regular meetings now between gas and electric utility planners.

There are unique circumstances in every region of the country, and the Northwest power industry has a long history of working collaboratively to address common issues and reach common goals. The groundwork for collaboration has been laid over decades. The electricity and natural gas convergence issues are another chapter in the way the region’s utilities and regulators address and resolve operational, policy, and planning issues.
Critical Issues and Risks for the Northwest

This whitepaper raises a number of issues that must be addressed as the Northwest adds more natural-gas fired generation to its resource portfolio. Leaders in the region’s electricity and natural gas industries have teamed up to study the challenges posed in several areas. An ongoing effort is under way to make sure issues are studied in detail and resolved. BPA is playing a major role in this effort.

In particular, BPA and utilities are drawing on the wealth of knowledge about regional power operations and the history of collaboration to tackle the issues. There are already key pieces in place, like the regional associations and the Northwest Mutual Assistance Agreement, that provide a springboard for discussions and participants for the work groups that are necessary to address the issues and resolve them in a way that is appropriate for the Northwest power system.

The pending closure of two coal plants and the rapid expansion of wind generation have near-term implications for the region’s gas infrastructure. The region has already undertaken joint gas and electricity planning efforts and is on the road to finding collaborative solutions the Northwest can own and fully support.