Is North American Natural Gas Infrastructure Up to Complementing Wind, Solar?

Donald F. Santa Jr.

While there has been a lot of discussion within the electric power industry about integrating electric generation from renewable sources of energy, very little attention has been devoted to how this change might affect the systems that supply fuel to electric generators.

Given the increasing role of natural gas–fired generators as part of the overall electric-generating fleet and the capability of some kinds of gas-fired generators to provide the rapid ramping needed as part of this integration, it makes sense to address this issue from a natural gas perspective. The key questions are: What does greater use of renewable energy sources mean for the natural gas industry? and Will the natural gas industry require new or different services and infrastructure to help accomplish this integration?

The Interstate Natural Gas Association of America (INGAA) Foundation retained ICF International to help answer these questions. The report, *Firming Renewable Electricity Power Generators: Opportunities and Challenges for Natural Gas Pipelines*,[1] released this past spring, found that the critical issues for natural gas in connection with integrating intermittent renewable generators have much more to do with pipeline deliverability and operational and contractual issues than they have to do with natural gas consumption. There will not be a significant amount of natural gas consumption in connection with these firming generators. In fact, the net effect of increasing renewables may be that less natural gas is consumed.

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METHODOLOGY AND OVERALL RESULTS OF THE STUDY

To answer the central questions about the effects of renewables on the natural gas infrastructure, ICF first forecasted the growth in renewable power generation that is likely to occur over the next 15 years. This resulted in a forecast of 105 gigawatts of new renewable power generation, of which 88 gigawatts would be intermittent wind power.

Second, for purposes of dealing with the variability of wind power, the study made a distinction between the expected variability of wind power (which is accounted for when wind is bid into the electric system) and forecast error (which cannot be readily accounted for when bids are made). It was this latter variability that the study assumed must be backed up in some manner. (See **Exhibit 1**.)

Third, the study acknowledged that intermittent generation could be firmed by various means in addition to gas-fired generators. These include demand-side options, pumped storage hydro, compressed air storage, and other options. Still, for purposes of establishing an outer bound on the natural gas implications, the study assumed that all intermittent generation would be backed up using gas-fired generation.

Fourth, the study estimated that as much as 33 gigawatts of gas-fired capacity could be needed to respond to forecast error in connection with the 88 gigawatts of intermittent renewable capacity. Some of this might be already-installed gas-fired capacity and some of it might be new capacity. The total natural gas use associated with this firming generation could total about 440 billion

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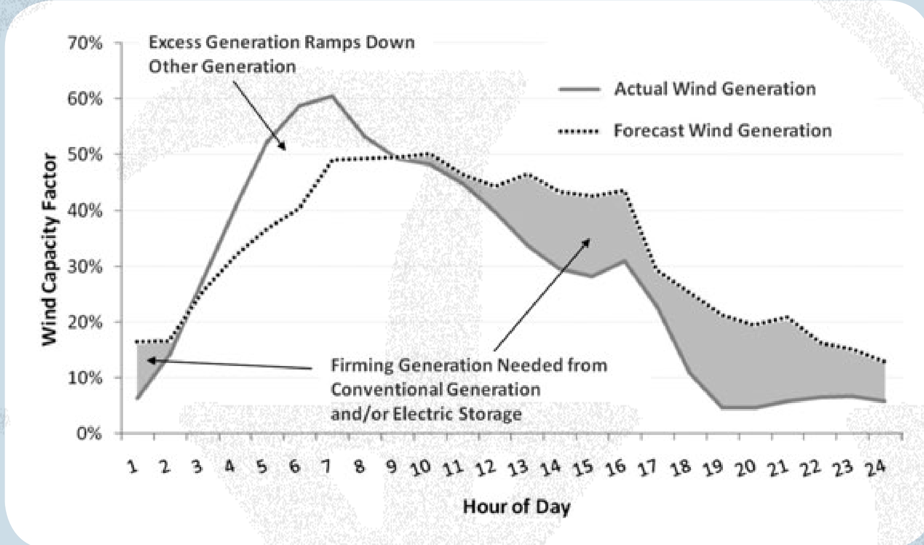
Exhibit 1. Firming Intermittent Wind Generation



cubic feet by 2025, equal to only about 2 percent of total current US gas consumption.

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REACTION TO THE STUDY

Some have questioned the assumptions underlying ICF's modeling regarding the costs and consequences of integrating an increasing amount of intermittent renewable generation.[2] This, if anything, is the tip of the iceberg of a much larger debate within the electric power industry. Still, it is fair to say that the integration of an increasing level of renewables will have implications for how the electric grid is operated and will affect how other kinds of generators are used. These implications in turn will have implications for the sources of energy that fuel those generators and the systems that deliver those fuels.

As already noted, the study acknowledges that there are other alternatives for addressing the issues created by the need to integrate a greater amount of intermittent renewable generation. Still, the study indicates that natural gas–fired generation is one of the most cost-effective alternatives for meeting this need. Therefore, even if the market ultimately relies upon a portfolio of technologies to provide the answer, it is safe to say that natural gas–fired generation will play a role and that we should be thinking about the consequences for the capabilities and services that will be demanded from natural gas pipelines.

The study indicates that the impacts on gas pipeline capacity and services largely will be localized. Even if the total magnitude of natural gas demand and infrastructure is different from what is estimated in the study, these challenges still may need to be addressed in locations where rapid-ramp-rate generators create special demands for natural gas pipeline deliveries.

It is important to note that many of the natural gas supply and pipeline issues that arise in connection with the role of natural gas in renewables integration also are present in connection with the increased utilization of natural gas as a fuel for electric generation. As a result, this discussion also highlights questions that will need to be addressed as natural gas is used increasingly for electric power generation.

REAL-WORLD CHALLENGES

The challenges for natural gas pipelines associated with serving firming generators can be explained by examining, in order, the following three topics:

- How are natural gas pipelines and pipeline services typically designed?

- What are the challenges associated with serving electric power generators generally?
- How might these challenges change or be amplified if the generator will be relied upon to firm intermittent renewable resources?

Natural gas pipelines are designed to meet the obligations of natural gas shippers (customers) that hold firm pipeline capacity. There is no natural gas equivalent to the reserve margin for electric power. If a pipeline is fully subscribed by firm shippers and if all of those shippers are using their contractual entitlement to firm pipeline capacity to the full extent, there is no capacity left for shippers that do not hold firm capacity.

While many pipelines provide hourly flexibility, most pipelines are designed to provide uniform service over a 24-hour period (a concept that is sometimes referred to as "ratable takes"). Consequently, a pipeline can only provide a limited amount of hourly flexibility.

As a practical matter, a considerable amount of flexibility is available on most pipelines to serve nonfirm customers on all but a few days of the year. This is because under most conditions, firm customers do not demand their full contractual entitlement at the same time. This excess capacity can be used to serve nonfirm customers, and it provides a pipeline the ability to accommodate demands for service on a nonratable basis.

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On a typical pipeline (and particularly one serving a consuming market), the bulk of the firm capacity is held by local gas distribution companies (LDCs) that primarily serve residential and commercial natural gas consumers. These LDCs contract for firm pipeline capacity as part of their plan for meeting peak-day demand (typically the coldest days of the winter when the demand for space heating will be the greatest). On a peak winter day, an LDC will be using all of its contracted firm pipeline capacity and will not relinquish that capacity at any price because access to the capacity is essential for the LDC to meet its public service obligation.

The rest of the time, an LDC will not need its full contractual entitlement for firm pipeline capacity and will be happy to mitigate the cost of holding that capacity by releasing it into the secondary market for firm pipeline capacity. Or if the LDC does not sell its spare capacity as released capacity, the pipeline will sell it as interruptible capacity.

Another important distinction between gas and electricity transmission is the speed at which the molecules move. Natural gas moves through a transmission pipeline at about 20 miles an hour. In other words, compared with the instantaneous transmission of electricity, natural gas moves at a snail's pace. This means that there is a difference between the commercial construct for transporting natural gas and the physical realities of what is required to deliver a molecule of natural gas at a time and place requested by a customer. In the commercial setting, a shipper may nominate gas for receipt by the pipeline at 11:00 A.M. at a point in Louisiana for delivery to its facility in New Jersey at 9:00 A.M. the next day. In the real world, however, the package of natural gas molecules received by the pipeline in Louisiana is not the same package of molecules that gets delivered less than a day later in New Jersey.

Physically, a pipeline operator must manage the inventory of shipper-owned natural gas that already is in the pipeline to make the physical deliveries called for in the commercial transaction. By managing "line pack," the pipeline-owned gas in the system that is necessary to maintain pressure to allow the pipeline to operate, the pipeline operator ensures that an "inventory" will be on hand to meet customer nominations and that it can provide intraday flexibility.

This management is easy enough when delivering natural gas on a ratable basis or even when dealing with shifts in demand that can be reasonably foreseen, like a forecast for a cold front that is known several days in advance. But this becomes more challenging when dealing with the significant and rapid swings in demand that can occur with electric generators and even more dramatic swings with rapid ramp rates.

When you add electric generators to the equation, you once again need to evaluate the two dimensions to the equation—the commercial and the physical. On the commercial side, there often is little incentive for electric generators to hold firm pipeline capacity. This disincentive is particularly true in restructured

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wholesale power markets in which generators have no reasonable assurances that all costs will be recoverable and do not know whether they will be dispatched. The cost of firm pipeline capacity adds to the generator's fixed costs and makes it less competitive.

Pipeline capacity in the secondary market will be available most of the time, often at a discounted rate. During the few days of the year when capacity is not available, the generator can choose not to run or else it can choose to use an alternative fuel, if available. From a wholesale generator's perspective, it is a rational choice to opt for interruptible service.

Furthermore, even when electric generators hold firm pipeline capacity, there may be complications associated with scheduling deliveries of natural gas consistent with dispatch of the generator. While natural gas pipeline scheduling is uniform across the United States, the electric scheduling day is not. Each grid operator has its own time frame for notifying generators about whether they will be dispatched. This dispatch notice often comes after a generator needs to make a timely nomination for service on its pipeline.

Under FERC rules, if the primary shipper (in this case, the generator) has not yet nominated service to his delivery point, another shipper may nominate service at that delivery point. And once the pipeline schedules service for the second shipper, it may not "bump" that shipper even if the primary shipper later determines that it wishes to take service at that delivery point.

These are not new issues. Working through the North American Energy Standards Board, the natural gas and electric power industries have tried unsuccessfully to standardize the natural gas and electric power days. Perhaps the new interest in natural gas and electric power interdependence will provide the impetus to resolve this issue.

Still, it is important to note that standardizing the energy day will not address the fundamental question about whether electric generators sign up for sufficient natural gas pipeline capacity. What happens when gas-fired generators are needed on those coldest days of the year when LDCs are fully using their firm pipeline capacity (i.e., a coincident winter peak)? Will this become a greater problem as natural gas–fired generators come to represent an increasing portion of the electric-generating fleet?

In other words, absent expansion of the pipeline or a reduction in firm load, the pipeline has only so much flexibility. As the number of nonfirm gas pipeline customers increases and as they seek service more frequently, there will be less flexibility to go around. Will the reliability of electric power delivery suffer as a result of the collective impact of individual generators making what for them are rational economic decisions? Do we need to look at how costs are recovered in restructured wholesale power markets and, in particular, the costs that must be incurred to ensure that the system remains reliable?

On the physical side, a key question becomes, What demands are placed on a pipeline when electric generators take deliveries of significant quantities of gas on short notice? How does this affect the ability of the pipeline to maintain line pack and system pressure sufficient to ensure that the pipeline can continue to meet its obligations to other customers (whether they are LDCs, other electric generators, or other customers)? What happens when a generator chooses to take gas that it has not scheduled?

To be sure, LDCs often take deliveries of natural gas on a nonratable basis. For example, takes may vary due to changing consumption patterns throughout the course of a day or due to changes in the weather that increase or decrease the need for space heating. Still, there is an element of predictability to these variations in gas delivery, and the order of magnitude is quite different from what can occur when a generator is dispatched.

FIRMING INTERMITTENT GENERATORS

Challenges are magnified further when providing pipeline services to generators that may be used to firm intermittent renewable generators or, for that matter, any gas-fired generators that will be expected to provide rapid ramping service on demand.

The special challenges for natural gas pipelines serving these firming generators are twofold. First, the infrastructure and services required to firm generators will be used only on a sporadic and infrequent basis. Second, accommodating the rapid ramp-up and ramp-down of gas-fired firming generation can cause major changes in gas requirements with only minutes' notice.

These characteristics also translate into challenges for recovering the costs of such services.

Because the services and facilities will be used on such a low load factor basis (perhaps as low as 15 percent), the unit cost is likely to be very high. (See **Box**.) This raises questions for both natural gas pipeline ratemaking and for how costs are recovered in electric power markets.

Most of the time and in most places, the natural gas pipeline system has considerable operational flexibility for managing intermittent demands for supplying natural gas for electric generators. Still, within some regions, incremental facilities and services may be needed to guarantee reliable, on-demand service for firming generators.

To illustrate these challenges, the study included transient flow modeling of several scenarios for a representative hypothetical pipeline that served multiple customers, including natural gas LDCs, other gas-fired generators, and firming generators. (See **Exhibit 2**.)

Natural gas pipelines are engineered to deliver natural gas at specified pressures. For example, a natural gas turbine may require that gas be delivered at a pressure of at least 550 pounds per square inch. (If the pressure falls below that level, the generator may trip.)

The transient flow modeling illustrated that, absent enhancements to pipeline services and infrastructure, there were periods in which the rapid, significant deliveries required by the firming generator could cause a reduction in pipeline delivery pressure sufficient to jeopardize service to both the firming generator and other customers on the system.

Depending on the circumstances, an answer to this problem could be a combination of adequate contracting for services and adequate infrastructure to support those services. Specifically, this could include increased pipeline lateral capacity (having the lateral pipeline serving the generator act as in-line storage), increased mainline capacity or increased compression, changes in nominating cycles, and new forms of no-notice service (a pipeline delivery service that permits customers to receive gas on demand without making prior nominations and without incurring scheduling and balancing penalties).

Of course, a pipeline will not make the capital investments necessary to support such services unless customers are willing to sign contracts that make it possible to recover such costs. This involves a couple of interrelated natural gas pipeline and electric power ratemaking questions.

- Will the costs be deemed attributable to the special needs of serving high-ramp-rate generators or will these costs be deemed attributable to preserving the quality of service for customers served under a generally applicable transportation service? In turn, this outcome will determine whether a pipeline offers a special tailored service for high-ramp-rate generators and other shippers that have similar natural gas delivery requirements.
- Either way, what can be done to create either an incentive or a mandate for generators to sign up for the pipeline services required to en-

Unit Costs Associated With Gas Transportation to Firming Facilities

Gas Plant Daily Requirement	Annual Maximum Volume at 100% Load Factor	Revenue Requirement	100% Load Factor Rate	Unit Cost at 15% Utilization	Unit Cost at 5% Utilization
MMcfd	MMcf per Year	Dollars	$/MMBtu	$/MMBtu	$/MMBtu
25	9,125	$912,500	$0.10	$0.67	$2.00

- Utilization of gas transportation facilities required for firming plants could be quite low—5 percent to 15 percent utilization.
- Capital costs must be spread over that relatively low utilization.
- Thus, per-unit costs of the facilities could be quite high—six to ten times greater than comparable facilities operating at 100 percent load factor.
- Cost recovery tends to be an issue for low-utilization facilities.

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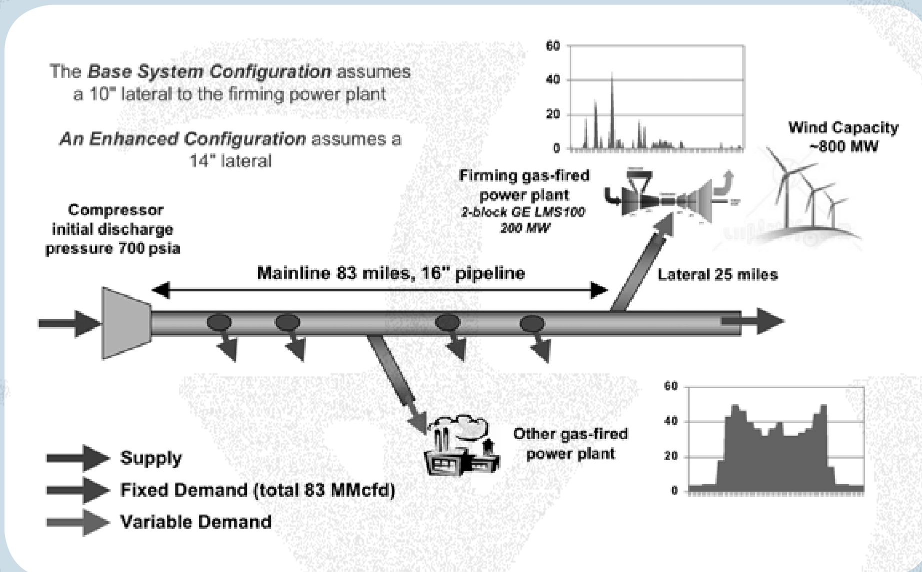
Exhibit 2. Planning for Intermittent Generation—Dynamic Flow Modeling Example for Gas Pipeline Facilities



sure the reliable delivery of natural gas, particularly for generators that must be available to maintain the reliability of electric service? This question must be solved on the electric power side of the equation. And as noted elsewhere, a key component is providing some assurance that the cost incurred for such services will be recoverable in the electric power market.

We realize that there are multiple debates within the electric power industry over whether particular costs should be spread across the entire market because they are incurred to create a system benefit or whether the costs should be assigned to particular market participants because of their role in causing the need to incur such costs.

We do not choose sides in that fight. But we do suggest that to the extent that the cost of natural gas infrastructure and pipeline services are deemed part of what is required to maintain reliable electric power service, then the recovery of such costs as part of electric power rates should be addressed.

CONCLUSIONS

Despite numerous challenges and assuming that shippers sign up for the services necessary to meet their particular and sometimes unique needs, there are no operational impediments to natural gas pipelines being able to deliver natural gas reliably to electric generators. The challenge is whether electric power markets are structured in a way that provides incentives for shippers to sign up for the services necessary to ensure the reliable delivery of natural gas.

The answer will involve a combination of natural gas pipeline ratemaking and electric power cost-recovery issues. What will the natural gas services look like and what will be the cost? And to what degree will potential customers for such services have assurances that the cost of such services can be recovered?

There are a variety of options for dealing with the intermittency of renewable generation. All of them will involve incurring additional costs, which will have to be borne. All that we ask is that natural gas options have an equal opportunity to compete and that, if natural gas is chosen, there be the ability to recover the costs of the investment necessary to provide reliable service.

NOTES

1. INGAA Foundation. (2011, March). *Firming renewable electricity power generators: Opportunities and challenges for natural gas pipelines*. Retrieved from http://www.ingaa.org/cms/31/7306/9622.aspx.
2. Penn Energy. (2011, March). *Natural gas-fired generation needed to back up renewables, report says*. Retrieved from http://www.pennenergy.com/index/power/display/9394478042/articles/powergenworldwide/gas-generation/o-and-m/2011/03/Gas-backing-renewables.html.

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