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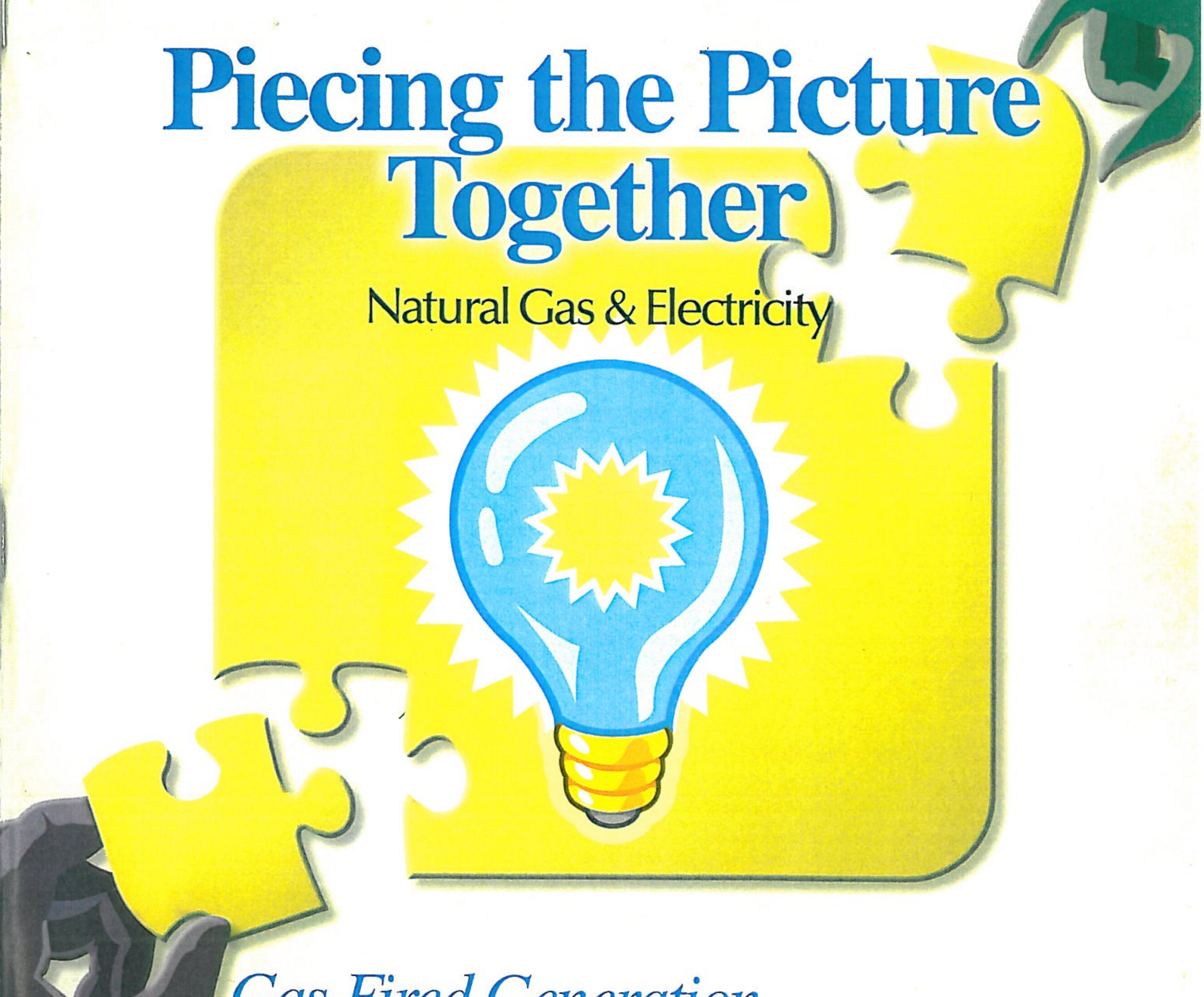
Piecing the Picture Together
Natural Gas & Electricity



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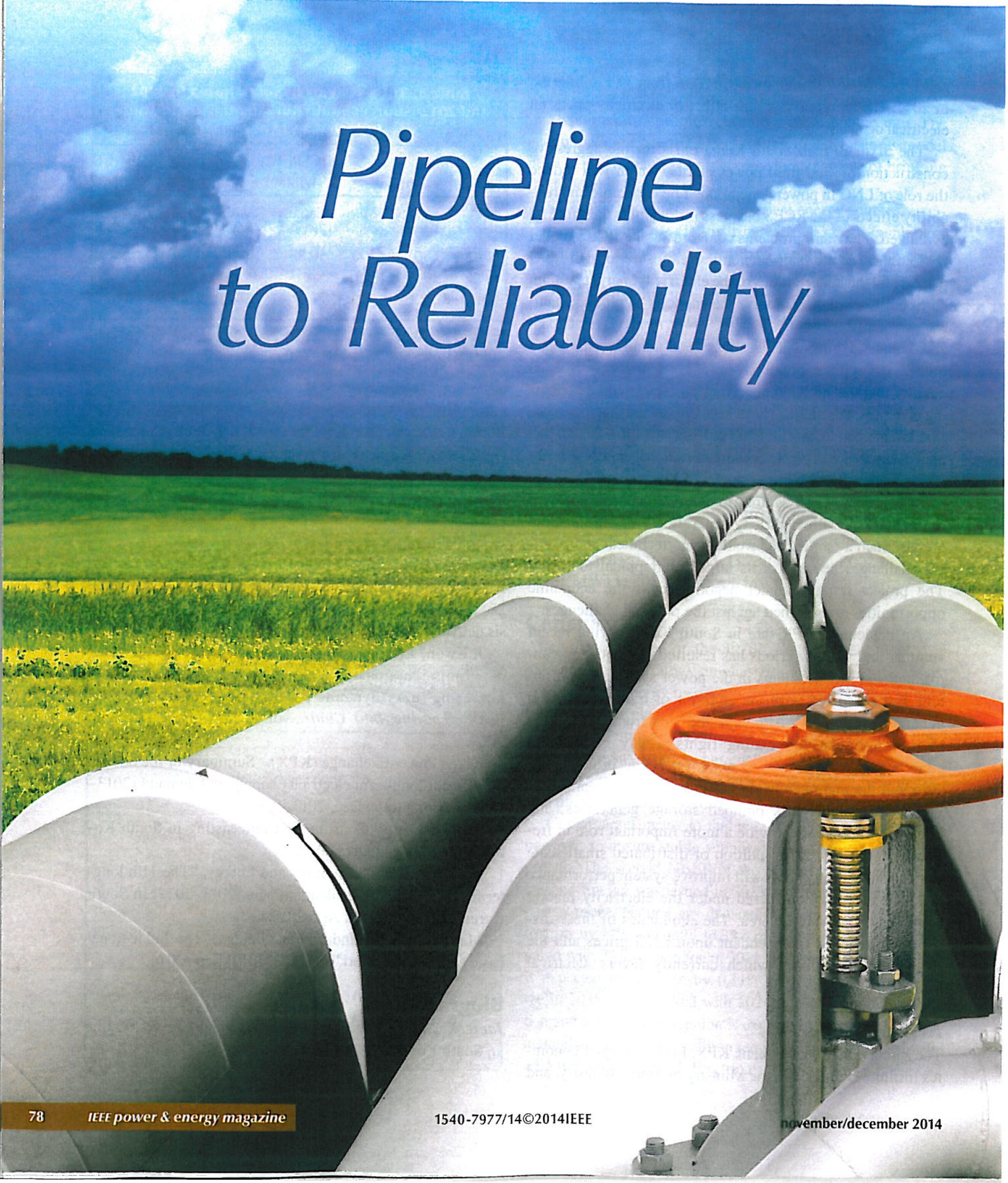
Unraveling Gas and Electric Interdependencies Across the Eastern Interconnection

Pipeline to Reliability



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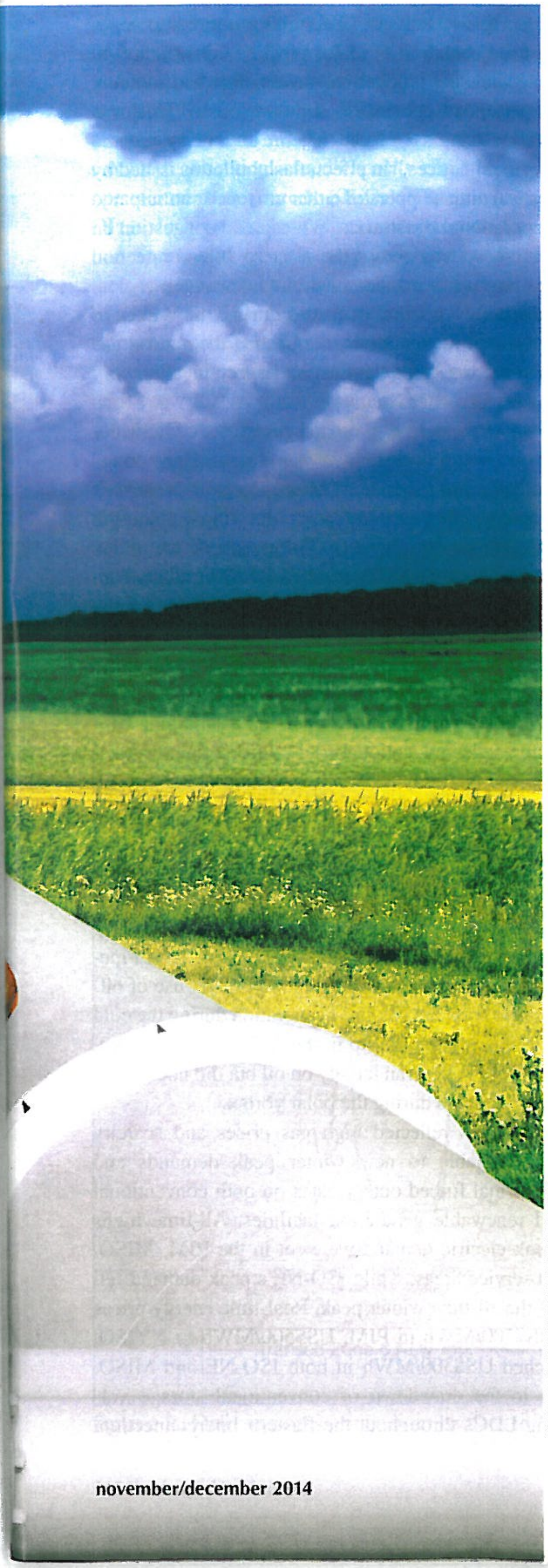
By Richard Levitan, Sara Wilmer, and Richard Carlson



UNCERTAINTIES SURROUNDING THE CONTINUED operation of older coal generation units, the increased penetration of renewable resources, and the aging or retirement of certain nuclear units have exposed vulnerabilities in the natural gas supply chain. The increased availability and low price of natural gas for electric generation in many parts of the United States compounds them by increasing the economic pressure on various non-gas-fired base-load generation plants. Our growing dependence on natural gas as a primary fuel for electricity generation offers environmental and efficiency benefits, but it also presents operational challenges for independent system operators (ISOs) and regional transmission organizations (RTOs) that depend on the natural gas pipeline and storage network to facilitate reliability objectives. During the peak heating season, pipeline congestion can result in interruptions of gas deliveries to those gas-fired generators lacking primary firm entitlements. Scheduling restrictions associated with the provision of nonfirm transportation for gas-fired generators stress the capability of the electric system to meet demand and maintain operating reserves, as RTOs must quickly replace output from more efficient natural gas-fueled combined-cycle plants and quick-start peakers to maintain electric reliability. In this article, we address the gas-electric interdependencies across the Eastern Interconnection that are the subject of a multitarget research project sponsored by the U.S. Department of Energy (DOE) with the participation of PJM Interconnection, Midcontinent Independent System Operator (MISO), New York Independent System Operator (NYISO), ISO New England (ISO-NE), TVA, and the Independent Electricity System Operator of Ontario (IESO), collectively known as the participating planning authorities (PPAs).

Constraints on natural gas deliverability have been observed sporadically for several years. From 3 to 7 January 2014 and then again in the last week of that month, frigid arctic air masses blanketed much of the eastern United States. Meteorologists have referred to such frigid arctic air masses as examples of the "polar vortex," a name that has since stuck in planning circles, making it overnight into the lexicon of gas-electric interdependencies. Of critical importance, this study is all about seeing how the natural gas supply chain flexes when stressed. The polar vortex and subsequent vortex-like events highlighted the gas-electric interdependencies that electric planners and system operators assess in safeguarding the reliability of the electric grid.

Since the early 2000s, there has been heightened regulatory interest on the part of the DOE, the Federal Energy

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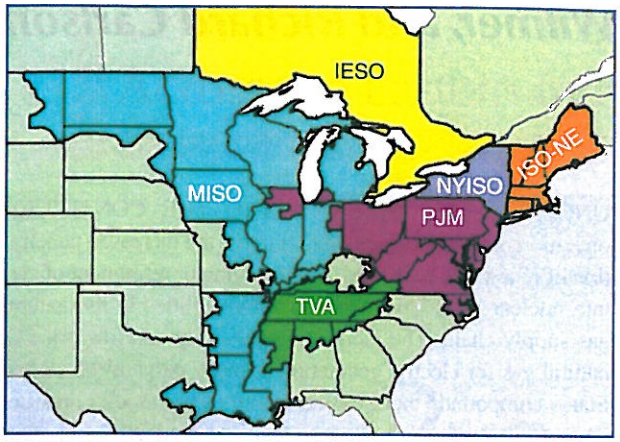

figure 1. A geographic overview of the study region.

Regulatory Commission (FERC), the North American Electric Reliability Corporation (NERC), and state regulatory commissions in the gas-electric interfaces that affect infrastructure adequacy. Accordingly, in February 2013 DOE directed the Eastern Interconnection Planning Collaborative (EIPC) to investigate these issues under an extension to an existing grant known as the Gas-Electric System Interface Study. By August, the PPAs developed and posted a statement of work that set forth a four-part study framework:

- **Target 1:** a baseline assessment of the current gas infrastructure in the regions served by the six PPAs (collectively known as the "study region")
- **Target 2:** quantification of natural gas required by generation plants and residential, commercial, and industrial (RCI) customers during the peak winter and summer periods of 2018 and 2023, including identification of likely pipeline and/or local distribution company (LDC) bottlenecks affecting deliverability as well as the frequency and duration of such locational constraints
- **Target 3:** hydraulic simulation analysis of infrastructure capability to meet both RCI and generation gas demands when disruptive gas-side or electric-side contingencies are postulated
- **Target 4:** engineering and economic analysis of dual-fuel capability in comparison with the incremental cost of firm pipeline transportation rights.

In October 2013, EIPC selected Levitan & Associates (LAI) to commence work on the four-part target research sponsored by DOE. The project is scheduled for completion in June 2015. The EIPC gas-electric study region is shown in Figure 1.

This article was prepared for publication in early July 2014. At that time, only the Target 1 results were available to the PPAs and stakeholders. Emphasis is therefore placed on the study approach and modeling framework formulated by LAI, including the assumptions and sources of input data. We also address how the stakeholder process informed and guided EIPC's research goals and objectives. All relevant information and study results are posted on the EIPC Web site.

Pricing the Polar Vortex

During the polar vortex of 3–7 January 2014 and the subsequent vortex-like conditions that occurred later that month, gas prices soared to new highs at key pricing points across the Eastern Interconnection, signaling unprecedented and extreme economic and operating conditions on the pipelines and storage facilities that serve LDCs and generation companies. Against the backdrop of major pipeline construction to accommodate shale gas production, never before had so many pipelines experienced congestion simultaneously. This was coupled with declarations of force majeure and the systematic posting of "critical notices," in effect, flash bulletins issued by the pipelines warning shippers of either current or anticipated short-term operational constraints. Widespread congestion on the gas pipeline system across the Eastern Interconnection caused cascading performance constraints across the region. The cold weather events that occurred during the winter of 2013–2014 resulted in conditions that pushed the natural gas and electric systems serving the Eastern Interconnection very close to their performance limits.

Spot gas prices for delivered natural gas exceeded US$100/million Btu on several occasions at major gas trading points serving New York and PJM, i.e., Transco Z6 Non–New York (TZ6-NY), Transco Zone 6 New York, and Transco Zone 5. Prices at Algonquin Citygates (AGT-Citygates), the index of relevance for New England, reached US$73/million Btu. Prices at Chicago Citygates, the index of relevance for the western portion of PJM's RTO and a portion of MISO-North, exceeded US$40/million Btu. The daily spot prices for these trading points from January to March 2014 are shown in Figure 2. The inset graph on the upper right-hand side captures the unprecedented regional-basis differential for brief intervals between NYISO and ISO-NE, reflecting the blowup in the TZ6-NY price during the polar vortex and subsequent cold snap in late January and the less radical spike in the AGT-Citygates price. Paradoxically, NYISO realized more than a billion cubic feet per day of new pipeline capacity into downstate New York in November 2013 but still witnessed volatile and sky-high gas prices on many days in January 2014. Pipeline constraints in New England resulted in greater use of oil-fired resources to supplant gas-fired generation during the cold snaps, thus tempering the run-up in the AGT-Citygates price. Dual fuel units in NYISO ran largely on oil but did not temper the run-up in gas prices during the polar vortex.

Electricity prices reflected high gas prices and scarcity conditions attributable to new winter peak demands and higher-than-normal forced outage rates on both conventional thermal and renewable generation facilities. All-time highs in winter peak electric demand were set in the PJM, MISO, and NYISO service areas, while ISO-NE's peak demand fell just short of the all-time winter peak. Real-time energy prices exceeded US$700/MWh in PJM, US$500/MWh in NYISO, and approached US$300/MWh in both ISO-NE and MISO. In response to the drawdown of conventional storage volumes serving LDCs throughout the Eastern Interconnection, energy prices in the PJM and MISO service areas approached US$2,000/MWh. Emergency petitions were filed by PJM and NYISO to retroactively lift the US$1,000/MWh cap in response to the unprecedented superspike in delivered gas prices. FERC responded practically overnight to the growing crisis, granting the PPAs' requests to lift the cap and thereby allowing generators to recoup the underlying cost of producing energy.

During the polar vortex and the subsequent vortex-like events in the fourth week of January, many of the pipelines serving LDCs and gas-fired generators throughout the Eastern Interconnection issued capacity constraint warnings and operational flow orders (OFOs). Pipeline operators issue OFOs during periods of pipeline congestion to protect pipeline operational integrity and generally notify shippers that their transportation services may be restricted. The issuance of alerts and OFOs generally discouraged but did not preclude shippers with nonfirm transportation arrangements from submitting timely nominations for natural gas, since these shippers knew that nonfirm nominations would probably not be scheduled. A shipper's submission of a timely nomination for the use of the pipeline system to serve gas-fired generation is akin to booking a seat on the shuttle from Boston to Washington, D.C., a week or the day before the desired travel date: unless the flight is sold out, the airline will typically accommodate the reservation request. The prospect of getting a seat when the booking is done last minute—in other words, on the day of travel—can be daunting, especially during the peak holiday rush. Shippers with nonfirm transportation arrangements that did submit timely nominations for natural gas that were subsequently scheduled faced "bumping." Bumping is the pipeline equivalent of being told to get off the plane after having boarded.

Shippers with nonfirm transportation arrangements also faced curtailments and interruptions, as well as significant penalty exposure resulting from enforcement of pipeline tariff ratable take provisions, i.e., about 1/24th of the daily quantity per hour. During the frigid portion of the winter of 2013–2014, shale gas production remained robust: daily production was reduced by only about 0.8 billion ft^3 per day due to well freeze-ups and related operational constraints for several days during January, a 6% reduction in average production from Marcellus. The run-up in gas prices therefore reflected delivery constraints across the supply chain as well as the coincidence of extreme cold across the Eastern Interconnection, which significantly increased the demand from customers as well as electric generation. This coincidence enabled gas producers with a variety of transportation options to deploy their respective portfolios to the highest economic value, often in nearby markets rather than at or toward the terminus of the supply chain in New Jersey, New York City, or New England. Like LDCs with firm entitlements, the distinct minority of gas-fired generators that possessed firm transportation entitlements were generally able to obtain sufficient deliveries to perform at full power output. TVA, for example, has primary firm entitlements to serve its gas-fired generators. Generators in Ontario have primary firm entitlements as well. Certain other generators across the study region have firm entitlements, but that is the exception not the rule.

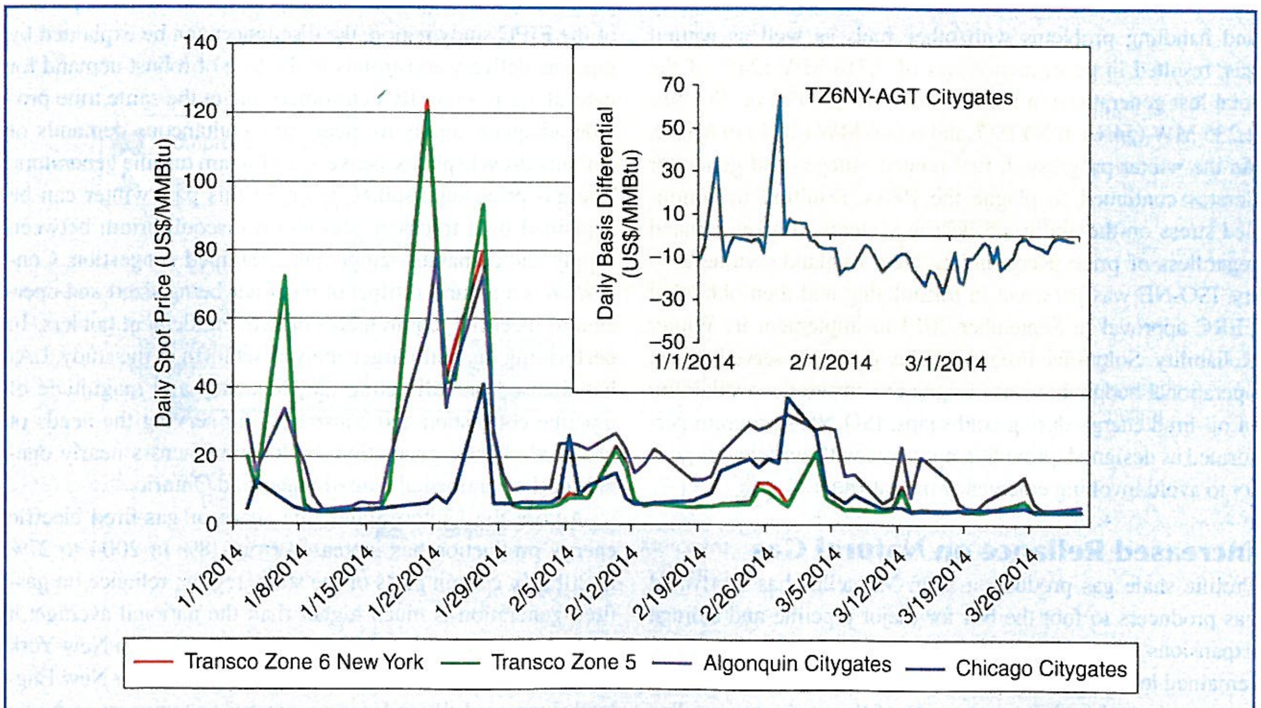

figure 2. Daily spot gas prices from January to March 2014.

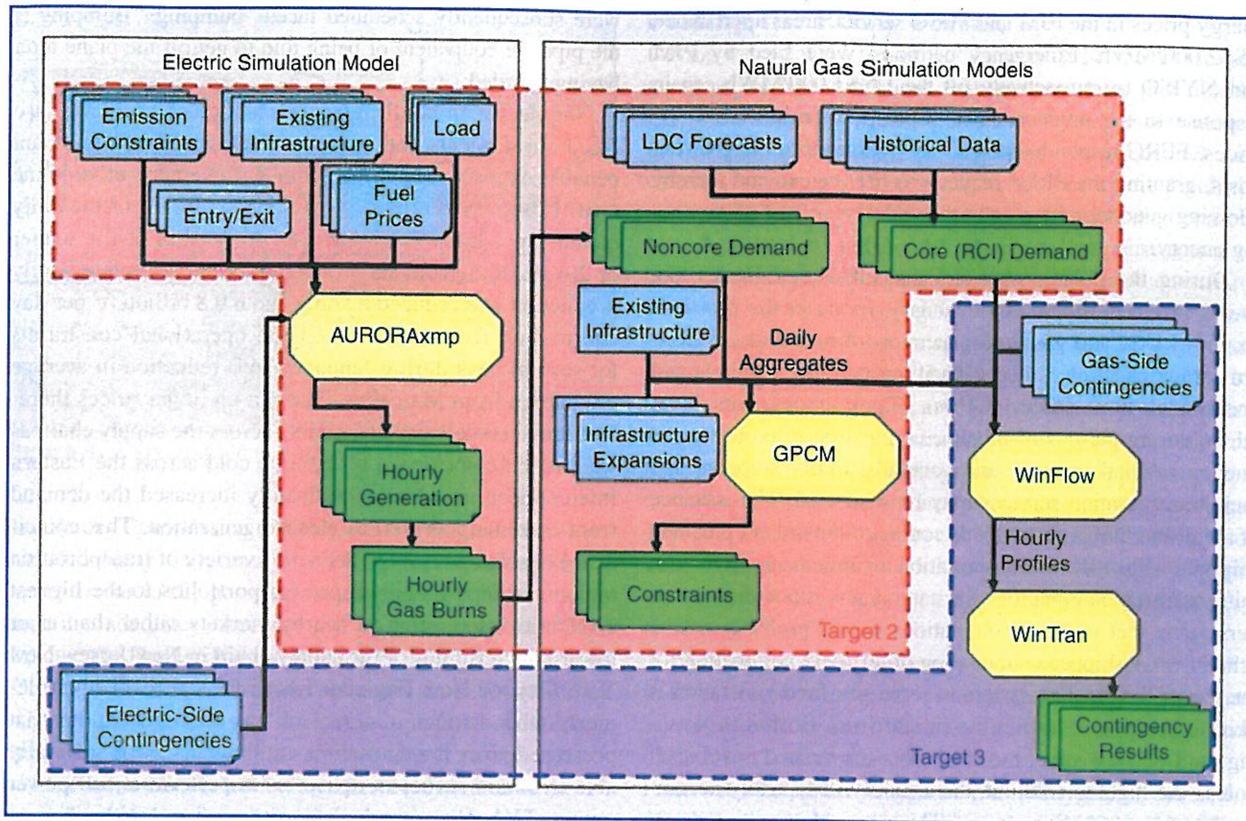

figure 3. Modeling system interactions.

During the polar vortex, FERC reported that lost generation due to forced outages and derates amounted to 41,336 MW in PJM, 1,473 MW in ISO-NE, 4,135 MW in NYISO, and 32,813 MW in MISO. Fuel issues, including deliverability and handling problems with other fuels as well as natural gas, resulted in generation losses of 9,718 MW (24% of the total lost generation) in PJM, 1,473 MW (100%) in ISO-NE, 2,235 MW (54%) in NYISO, and 6,666 MW (20%) in MISO. As the winter progressed, fuel-related outages and generator derates continued to plague the PPAs, resulting in continued stress on the ability of electric systems to meet demand regardless of price. Recognizing New England's vulnerability, ISO-NE was prescient in formulating and then obtaining FERC approval in September 2013 to implement its Winter Reliability Solutions Program. The program served as an operational hedge that was designed to ensure the availability of oil-fired energy during cold snaps. ISO-NE's program performed as designed, providing operators with sufficient liquidity to avoid invoking emergency measures.

Increased Reliance on Natural Gas

Prolific shale gas production from Marcellus has motivated gas producers to foot the bill for major pipeline and storage expansions across the study region. Natural gas prices have remained low "into the pipe" but have nevertheless been high or even skyrocketed in many parts of the study region. The gap between the cost of gas into the pipe and the value of natural gas in end-use markets reflects a disconnect between supply and demand. Experience shows that disconnects of this sort are ultimately monetized by various market participants: pipeline operators, producers, and end users. Across a portion of the EIPC study region, the disconnect can be explained by pipeline delivery constraints in the face of robust demand for natural gas to serve RCI customers and at the same time provide adequate supply to meet the simultaneous demands of combined-cycle plants, peakers, and steam turbine generators. The gas price superspikes observed this past winter can be explained by a transient, short-term disequilibrium between supply and demand—simply put, sustained congestion. Congestion is a natural artifact of pipelines being sized and operated to meet the requirements of firm entitlement holders. In performing the multitarget analysis set forth in the study, LAI has focused on calibrating the frequency and magnitude of pipeline congestion and constraints for serving the needs of gas-fired electric generation, by location, across nearly one-half of the continental United States and Ontario.

Across the United States, the share of gas-fired electric energy production has increased from 18% in 2004 to 27% in 2013. In certain parts of the study region, reliance on gas-fired generation is much higher than the national average: it accounts for as much as 45% of total generation in New York and close to 50% of all the electricity produced in New England. Increased dependence on natural gas appears to be an inexorable trend across the Eastern Interconnection, one that requires active management of gas-electric interdependencies to ensure bulk power reliability, security of supply, and the quick activation of mitigation measures by PPAs and pipeline operators when gas- or electric-side contingencies occur.

The shale gas phenomenon, stringent environmental regulations, and the resultant economic pressures on the nation's fleet of coal-fired generators have heightened the PPAs' dependence on pipeline infrastructure across the Eastern Interconnection. Many gigawatts of coal-fired capacity are expected to be retired over the next several years. In our opinion, the Eastern Interconnection region's increased dependence on natural gas for electric generation raises complex but solvable challenges associated with the management of pipeline and storage infrastructure to keep pace with the coincident demand requirements of gas utility loads and power generation loads. These problems show up throughout the heating season (November through March) but are also evident in some parts of the study region during the peak cooling season as well. The substantial increase in the use of gas for power generation has challenged the ability of the gas delivery system to meet the simultaneous demands of RCI customers and the expanding fleet of efficient, gas-fired generation plants during periods of high demand.

Modeling Framework

Completion of the study required extensive modeling of the gas and electric systems, particularly for Targets 2, 3, and 4. Four different commercially available modeling systems were used, as illustrated in Figure 3, which shows key inputs, outputs, and data transfers among models. AURORAxmp is a comprehensive electricity market modeling software program used by many stakeholders and electric planners throughout North America. The core of the program is a fast hourly dispatch algorithm that simulates the economic commitment and dispatch of power plants in a chronological, multizone, transmission-constrained system. The AURORAxmp model is well suited to the purposes of this study for two reasons. First, it is relatively easy to reconfigure the model's data structures so as to incorporate the numerous varying input assumptions within the different control areas of the six PPAs. Second, it executes quickly enough to be practical for performing and validating multiple scenario runs for the large study region.

The Gas Pipeline Competition Model (now called simply GPCM) is a modeling product that represents the integrated natural gas market in North America and is used by LAI to simulate the flow of natural gas across the pipeline and storage infrastructure from producing areas to market areas throughout the study region. GPCM uses a *node-arc network*. Nodes

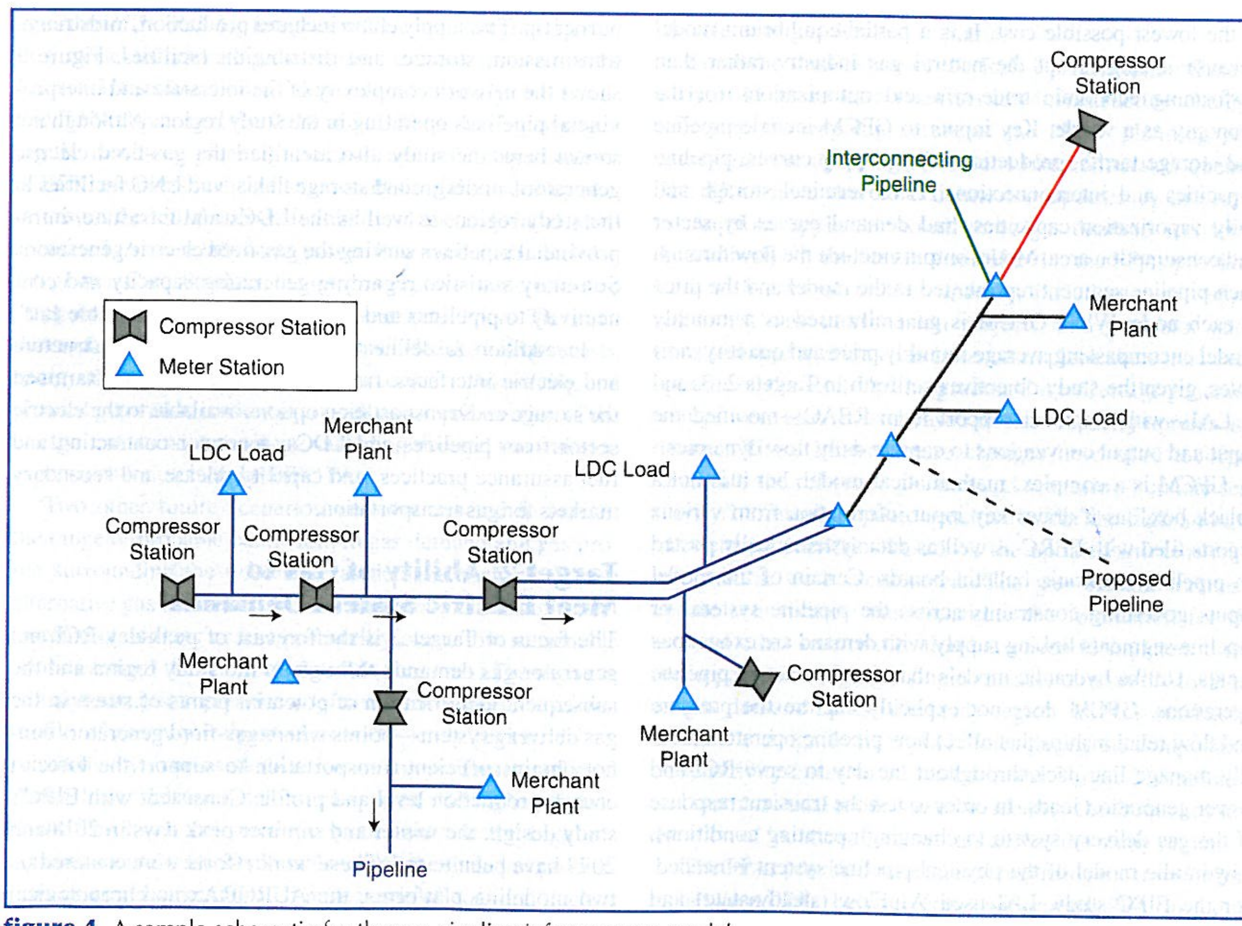

figure 4. A sample schematic for the gas pipeline infrastructure model.

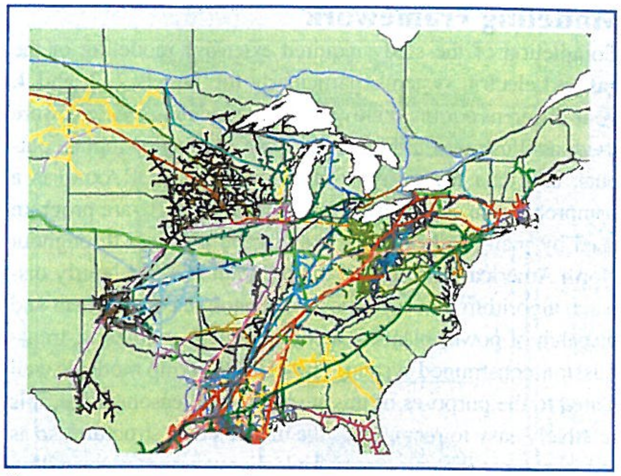

figure 5. Interstate and intraprovincial pipelines serving the study region.

represent production regions and supply basins, pipeline zones, interconnects, storage facilities, delivery points, and either specific large customers or groupings of smaller customers. Arcs represent gas transactions and flows, either spatial or temporal. The arcs have appropriate constraints that represent the actual pipeline flow capabilities between adjoining nodes.

GPCM uses partial-equilibrium economics to reach a solution in which supply and demand are balanced at each node at the lowest possible cost. It is a partial-equilibrium model because it singles out the natural gas industry rather than performing economic trade-offs and optimizations for the economy as a whole. Key inputs to GPCM include pipeline and storage tariffs, production basin supply curves, pipeline capacities and interconnections, LNG terminal storage and daily vaporization capacities, and demand curves by sector and consumption area. Model outputs include the flow through each pipeline segment represented in the model and the price at each node. While GPCM is generally used as a monthly model encompassing average monthly price and quantity variables, given the study objectives set forth in Targets 2, 3, and 4, LAI—with technical support from RBAC—modified the input and output conventions to capture daily flow dynamics.

GPCM is a complex, mathematical model, but it is not a "black box," as it draws key input information from various reports filed with FERC as well as data systematically posted on pipeline electronic bulletin boards. Certain of the model inputs governing constraints across the pipeline systems or pipeline segments linking supply with demand are exogenous inputs. Unlike hydraulic models that simulate actual pipeline operations, GPCM does not explicitly capture the pressure and flow relationships that affect how pipeline operators actually manage line pack throughout the day to serve RCI and power generation loads. In order to test the transient response of the gas delivery system to changing operating conditions, a hydraulic model of the physical pipeline system is needed. For the EIPC study, LAI used WinFlow (steady-state) and WinTran (transient) hydraulic modeling software provided by Gregg Engineering, Inc. Extensive hydraulic detail can be produced using the WinFlow-based pipeline simulation model of the interconnected pipelines and storage infrastructure across the study region. Technical input parameters to the steady-state model include pipeline diameters, segment lengths, compressor horsepower, discharge temperatures, velocities, maximum allowable operating pressures, elevations, and gas demands. The schematic diagram in Figure 4 illustrates the level of detail included in the hydraulic models.

The typical modeling process is to validate the model using known (generally peak day), steady-state operating conditions with WinFlow and then to use that model representation in WinTran to simulate transient conditions. WinFlow's modeling features include the ability to display the modeled system as a map featuring color-coded infrastructure information. This interface lets LAI zoom in or out and scroll for maximum visualization. Formulation of the steady-state and transient flow models provides the PPAs with a dynamic planning tool that reveals the gas-fired generation at risk when adverse events occur across the consolidated network of pipelines and storage facilities in the study region.

Target 1: A Baseline Gas Infrastructure Assessment

Energizing North America with natural gas requires a complex and multifaceted supply chain, from the wellhead to the burner tip. The supply chain includes production, midstream, transmission, storage, and distribution facilities. Figure 5 shows the network complexity of the interstate and interprovincial pipelines operating in the study region. Although not shown here, the study also identified the gas-fired electric generators, underground storage fields, and LNG facilities in the study region, as well as the LDCs and intrastate, intraprovincial pipelines serving the gas-fired electric generators. Summary statistics regarding generating capacity and connectivity to pipelines and LDCs are presented in Table 1.

In addition to delineating the natural gas infrastructure and electric interfaces, the Target 1 research also examined the storage and transportation options available to the electric sector from pipelines and LDCs, generator contracting and fuel assurance practices, and capacity release and secondary markets for gas transportation.

Target 2: Ability of Gas to Meet Electric System Demands

The focus of Target 2 is the forecast of peak-day RCI and generator gas demands throughout the study region and the subsequent identification of potential points of stress in the gas delivery system—points where gas-fired generators cannot obtain sufficient transportation to support the forecast energy production level and profile. Consistent with EIPC's study design, the winter and summer peak days in 2018 and 2023 have been tested. These work efforts were centered on two modeling platforms, the AURORAxmp chronological electric system model and the GPCM gas network model.

table 1. Generator statistics by PPA.

PPA	Total Capacity (GW)	Gas-Capable Capacity (GW)	% of Total	Interstate/Interprovincial-Served Capacity (GW)	Intrastate/LDC-Served Capacity (GW)
PJM	185	80	43%	40.3	38.7
MISO	177	69	39%	44.6	24.4
NYISO	38	21	55%	4.3	16.7
ISO-NE	35	18.6	54%	14.3	4.3
TVA	34	12.2	36%	9.9	2.3
IESO	33	9.9	28%	1.2	8.7
Total	502	210.7	42%	114.6	95.1

Three different gas demand scenarios were developed for Target 2: reference, high, and low. The reference gas demand scenario represents a forecast that is in accord with the economic, market, and regulatory assumptions characterizing each of the six PPAs' planning processes over the five- and ten-year study horizons. The starting point for the reference gas demand scenario was the Roll-Up Integration Case of the Eastern Interconnection prepared by the EIPC Steady State Modeling and Load Flow Working Group (SSMLFWG). The SSMLFWG consists of representatives from each NERC-registered planning authority (PA) that is party to the EIPC analysis team's agreement. The Roll-Up Integration Case is an integrated power flow model incorporating the regional expansion plans for the Eastern Interconnection as they existed in early 2013. The SSMLFWG prepared the 2018 and 2023 models by aggregating the resources, planning forecasts, and reliability standards of EIPC members, with sufficient analysis of the rolled-up plan to ensure the simultaneous feasibility of the individual plans submitted. As a steady-state power flow model, the Roll-Up Integration Case simulates the integrated power system for two "snapshots," the 2018 and 2023 summer peak hours. The input data to the Roll-Up Integration Case included the load forecasts, energy-efficiency and demand-side resources, and existing and planned generation resources, as well as a representation of the electric transmission topology, including planned transmission expansions for each of the EIPC PAs.

Two other future scenarios were constructed to bracket the range of probable bandwidth in gas demand and gas profile surrounding the reference gas demand scenario. These alternative gas demand scenarios were not intended to reflect extreme conditions or low-probability events but reasonable bounds around the realm of plausible outcomes. The high gas demand scenario represents a "plausible maximum" level and profile of gas requirements across the study region, driven primarily by increased deactivation or retirement of coal plants, lower delivered natural gas prices, and higher electric loads. The lower delivered gas prices used in the high gas demand scenario are attributable to prolific shale gas production, greater than anticipated retirements of coal and nuclear units, and higher electricity demand growth. Conversely, the low gas demand scenario assumes higher delivered gas prices, greater growth in renewable generating capacity, and lower electricity demand growth compared with the reference gas demand scenario. The low gas demand scenario represents a "plausible minimum" level and profile of gas requirements, driven primarily by the displacement of gas-fired generation as a result of the addition of renewable resources, higher delivered natural gas prices, and lower electric loads. The high and low gas demand scenarios represent energy futures in which one or more of the primary factors driving natural gas demand fall significantly outside the values reflected in the reference gas demand scenario.

Since the finalization of the Roll-Up Integration Case in early 2013, there have been certain infrastructure changes reflecting the ongoing nature of the PPAs' planning processes and the updating of various interconnection queues. The PPAs have therefore delineated updates to the input assumptions applicable to all three gas demand scenarios. Accordingly, in the first quarter of 2014, the PPAs provided LAI with lists of system updates, including new supply resources, new transmission projects, and generator additions and deactivations that have taken place since the development of the Roll-Up Integration Case. Certain generator ratings were also revised based on new capacity uprates and derates. These infrastructure changes have been incorporated into the reference gas demand scenario's "update sensitivity." Similarly, update sensitivities for the high and low gas demand scenarios based on the updated infrastructure information were constructed. The gas demand scenario update sensitivities thus constitute the foundation for the array of other sensitivities that have been formulated to test the impact of changing a single variable or a set of variables on gas demand across the study region. EIPC's stakeholders have had significant input in formulating the composition of sensitivity cases to be tested in the Target 2 simulation and mathematical models used to identify the frequency and duration of locational constraints across the study region.

The PPAs provided information regarding the transfer limits between PPAs, between zones within each PPA (including multizone simultaneous interface limits), and between zones and adjacent control areas. In the high gas demand scenario, the simplifying assumption has been made that new gas-fired generation resources would likely be located at or around deactivated generation stations in order to more fully utilize existing electric transmission infrastructure. In the low gas demand scenario, the simplifying assumption has been made that the additional renewable resources would likely be sited near the existing renewable resource locations across the study region. These assumptions allow for the identification of gas constraints when utilizing the existing and planned electric infrastructure to serve different levels of resources; this approach helps keep the focus of the analysis on gas infrastructure adequacy. The location of the specific new generation will ultimately be determined by generation providers that will take into account a number of factors, one of which will be the existing and planned gas infrastructure.

For each of the gas demand scenarios, the AURORAxmp multizonal electricity price forecasting model produced forecasts of the gas requirements of all gas-capable electric generating units within the study region for the peak winter and summer seasons of 2018 and 2023. The corresponding gas demand forecasts for the RCI sector were based on forecasts and regulatory filings by the LDCs operating in the study region, where publicly available. By necessity, the RCI forecasts encompass statistical analysis performed by LAI to promote standardized results. These data sources were augmented with information available in various LDC and pipeline company financial reports, as well as forecasts available from government or private sources, e.g., Canada's National Energy Board (NEB), the DOE, the U.S. Energy Information Administration (EIA), and industry trade associations. State or city programs oriented around accelerated LDC customer conversion from oil to natural gas for space heating were also incorporated.

Other industry data in the public domain reflecting past usage provided additional insight into the level and profile of RCI gas demand. In the event that forecast data were not available for a particular LDC, future demand was 1) estimated based on historical demand trends from a database of pipeline deliveries, 2) adjusted for generator gas demand using EPA emissions data, and 3) escalated using gas demand growth rates from EIA's *Annual Energy Outlook 2013*. Historical data were also used to bracket the high and low demand scenarios relative to the reference gas demand scenario, in the event that alternate cases were not available from the other forecast sources. Within each gas demand scenario, both winter and summer peak day forecasts were developed for each modeled year. Incremental demands resulting from new programs and initiatives that are not yet adequately reflected in the historical data trends were calculated separately as adders to extrapolated historical demand in order to fully estimate future RCI demand. One example of this type of initiative is former New York City mayor Michael Bloomberg's expanded Clean Heat program to convert housing authorities and other city buildings from heavy heating oils to natural gas.

With the forecasts of electric and RCI sector gas demands in hand, GPCM was utilized to evaluate infrastructure adequacy to meet the combined customer demands. For purposes of this analysis, the seasonal peak day was defined as the day with the highest electric sector gas demand based on the AURORAxmp model results. The study made the conservative assumption that RCI peak demand coincided with the peak electric sector gas demand day. The GPCM database was modified as necessary to include planned gas infrastructure expansions, as well as any additional expansions required to meet forecast increases in RCI gas demands. The "planned" gas infrastructure expansions incorporated in GPCM for model year 2018 included all projects with executed precedent agreements, as indicated by prefiling or filing a certificate application before FERC or in press releases or other news articles. Not included in the reference gas demand scenario pipeline additions were those projects on the drawing board, even those that ostensibly enjoy strong political support. These projects were instead tested in a sensitivity analysis focused on increased gas transportation out of the Marcellus Shale.

The GPCM model results were evaluated for each scenario (defined by gas demand scenario, season, and year) to identify those segments for which the full gas demand at downstream nodes cannot be delivered. For each such constrained segment, the primary cause of the capacity constraint was identified, i.e., the compressor station, discrete pipeline segment, or other facility that sets the throughput capacity of the GPCM arc. To determine the frequency and duration of the constraint, the unserved demand was compared with seasonal load duration curves based on AURORAxmp results and historical data for the electric and RCI sectors, respectively, to determine the number of days during which that segment was likely to be constrained.

Based on the constraints that were identified, we then tested demand reductions and capacity expansions to determine opportunities for mitigation. The demand reductions test simulated one or more generators' switching from gas to an alternate fuel. If the number of generators with existing dual-fuel capability was not sufficient to relieve the constraint, we identified additional generators that would need to install dual-fuel capability in order to maintain fuel assurance. On the gas delivery side, for constraints that were not aligned with previously announced proposed pipeline or storage projects, we formulated an infrastructure expansion that would alleviate the constraint, with benchmark cost estimates associated with the expansion. Perhaps equally important to the identification of constrained pipeline segments, LAI also identified areas with slack deliverability, either currently or based on projected changes in gas flow patterns as a result of continuing shale gas development, including the reversal of traditional flow to accommodate shale gas dynamics in the PJM, MISO, TVA, and IESO regions.

Target 3: Contingency Analysis

Based on the results and findings of the Target 2 analysis, a list of potential contingencies was developed for each gas

Risk factors are not fixed constructs: they are constantly changing in response to economic, regulatory, technological, and market dynamics.

demand scenario. Gas-side contingencies encompassed the loss of supply, loss of storage, loss of key pipeline segments (including a postulated guillotine cut to a marine segment), and loss of compression. The approximate footprint of the consequent generation at risk attributable to each gas-side contingency was first identified within GPCM, so that the relevant local infrastructure for each contingency could be defined for modeling in WinFlow and WinTran. By thus identifying appropriate boundaries for each contingency, LAI avoided the need to produce hydraulic models of the entire study region. This provided the PPAs with a state-of-the-art modeling tool that reveals the magnitude, duration, and spatial impact of a postulated gas-side perturbation in areas with concentrated gas-fired generation while simultaneously reducing the total cost of and effort required for the study.

The transient model solutions quantified how long a particular power plant or group of power plants would remain online following a postulated contingency event. The gas pressure required to maintain full load on large combustion turbines varies widely, from less than 400 psi to more than 900 psi depending on the type of gas turbine. For example, GE's LMS100 gas turbine requires gas supply to the engine at a typical pressure of 830 psig and a nominal pressure of 850 psig for full-power operation. Pressure losses outside the engine, such as those in metering and pressure regulation equipment, cause the pressure required at the connection to the pipeline to be even higher. On-site compression is required when the gas turbine full load required pressure exceeds the operational pressure the pipeline operator can guarantee. The existence of an on-site compressor will improve the ability of a gas turbine to accommodate variations in supply pressure. The gas pressure required to maintain operation at a combustion turbine is an order of magnitude higher than that required by gas-fired steam plants. Our study results also revealed whether there are viable pipeline work-arounds and sufficient line pack to enable at-risk generation to continue to operate for hours, minutes, or seconds beyond the gas contingency.

In addition to gas-side contingencies, we also considered various contingencies that might occur within the electric sector. The magnitude and location of regional gas infrastructure impacts associated with electric system outages were investigated in a variety of ways. Additional AURORAxmp simulations tested the impacts on the profile of gas use by generators when there is a loss of a large, nongas base-load generation plant or high-voltage transmission line. The resultant transportation constraints were affected as generation shifted from one location to another or from a nongas plant to a gas plant. Using the WinTran transient hydraulic model, we also tested the pressure impacts on gas pipelines resulting from a sudden loss of gas demand at particular plants and the potential adverse effects of the electric system restoration process following an outage on the operational capability of the pipeline, storage, and distribution infrastructure. This evaluation accounted for the iterative effects of balancing electric restoration with transient gas system constraints. The examination of a widespread blackout addressed reliance on electric compressors in key locations as well as the sustainability of line pressure and flow to achieve minimum MW loading requirements to ensure generator stability during the restoration process.

For both gas- and electric-side contingencies, the study examined ways in which the effects of these contingencies could be mitigated. On the gas side, potential operational workarounds involve alternate transportation paths—either on the same pipeline or an interconnected pipeline—as well as increased storage withdrawals. When operational contingencies arise, pipelines have demonstrated a common interest, that is, they have exhibited a high degree of cooperation enabling them to take immediate action to mitigate physical constraints. Demand-side measures were included in the solution set, such as identifying plants that are vulnerable to interruption and that would benefit from the installation of dual-fuel capacity. The study addresses the pros and cons of different solution sets in light of the commercial interests of primary entitlement holders, FERC and NEB precedent, and the environmental policies and planning criteria that state regulatory commissions and the Ontario Energy Board have recently promulgated.

Target 4: Analysis of Dual-Fuel Capability

Our Target 4 work efforts considered several aspects of dual-fuel operation. Initially, LAI constructed a database identifying the storage capacity and liquid fuel resupply methods at selected existing dual-fuel generators within the study region. In addition to data provided by the PPAs, we relied on such public sources as air permits, tank permits, and EIA for this data. LAI also examined the operating characteristics of dual-fuel units associated with burning either gas or oil. LAI prepared a comprehensive spreadsheet with key operational data for the principal gas turbines in simple and combined-cycle operation, including maximum output, heat rate, and other data for gas and liquid fuel operation.

Part of our Target 4 research and analysis addresses the ability of various turbine technologies to provide fuel switching "on the fly." In theory, new dual-fuel gas turbines can switch from gas to liquid fuel and back again while maintaining operations. In many cases, however, the units must be throttled back from 100% output to facilitate the switchover. We have therefore assessed the response of gas-only combustion turbines when gas supply pressures fall below design levels. In some cases, derating or tripping may not be a direct consequence of pressure sensing. Many gas turbines can operate stably at part load even if there is insufficient pressure for full load. In a situation examined for Target 3, for example, a trip may occur following a rapid pressure loss even if the final pressure is sufficient to sustain steady-state operation—not as a result of a control action initiated by a pressure measurement but rather due to flame dynamics in the combustors. Prominent manufacturers have supported EIPC's research objectives by providing information on the responsiveness of gas turbines to pressure variations and the ability of aeroderivative and frame gas turbine units to switch to liquid back-up fuel automatically in the event of a low-gas pressure signal. Most gas turbines can be supplied with an autotransfer capability triggered by a low–gas pressure signal that would switch the unit from gas to liquid backup fuel. This transfer should occur with no need for operator interaction, as long as the backup fuel system is operational and not disabled for maintenance or other reasons. As part of the Target 4 deliverable, LAI prepared a technical summary of the fuel-switching capabilities of various turbine units and an estimate of the reaction time required for each turbine type to switch from natural gas to oil.

An analysis of the liquid fuel market was performed, including the ability to provide backup fuel for dual-fuel power plants on a routine basis and limitations on that ability. LAI investigated the key infrastructure planning and operational issues surrounding liquid backup fuel storage and delivery capacities, delivery system flexibility for meeting short- and long-term demands of interruptible service customers, and costs and barriers associated with expanding oil infrastructure. We subdivided liquid fuel types by resupply option, from tanker trucks and barges to fixed pipelines from tank farms to the power plants, and provided perspective on how power plant oil refill efforts affect the petroleum delivery system when seasonal constraints tax the ability of truck haulers and barges to meet the coincident requirements of high-priority RCI customers while replenishing oil inventories at power plants in metropolitan areas.

Barriers to the use of alternative fuels were examined—for example, air permit restrictions on liquid fuel operation and siting restrictions on liquid fuel storage tanks. Drawing on LAI's experience on behalf of the PPAs, generation companies, electric distribution companies, and state regulatory bodies, we defined the operational issues associated with liquid fuel inventory management. The cost of incorporating dual-fuel capability was defined on a locational basis and included 1) the incremental capital cost for tanks, fuel inventory, burners, controls, and so on, 2) the loss of output, efficiency, or dispatchability, and 3) secondary cost considerations of property taxes, insurance, and so on, as well as other financial components.

Another integral task that was part of our Target 4 analysis pertained to the relative economics of dual-fuel capability versus incremental firm transportation to satisfy the PPAs' fuel assurance objectives. Drawing from the frequency and duration analysis conducted for Target 2 for the array of case sensitivities related to different energy futures and natural gas prices, LAI compared the annuitized cost of liquid fuel capability versus incremental firm transportation, where locational constraints are likely to preclude reliable plant operation on natural gas under nonfirm transportation arrangements.

Conclusions

The research and analysis that made up the four-part target study funded by the DOE have provided the six PPAs with valuable technical insights into risk factors affecting the delivery of natural gas to power plants across the study region. Experience shows that the risk factors are not fixed constructs: they are constantly changing in response to economic, regulatory, technological, and market dynamics. These dynamics can exacerbate gas infrastructure constraints, thus heightening concerns over electric reliability. The ebb and flow of gas-electric interdependencies are motivating the PPAs to maintain a variety of planning tools with which to safeguard reliability through rigorous study, the results of which inform stakeholders what's at risk, the magnitude of the risks, where the risks are, and what to do about them.

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For Further Reading

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