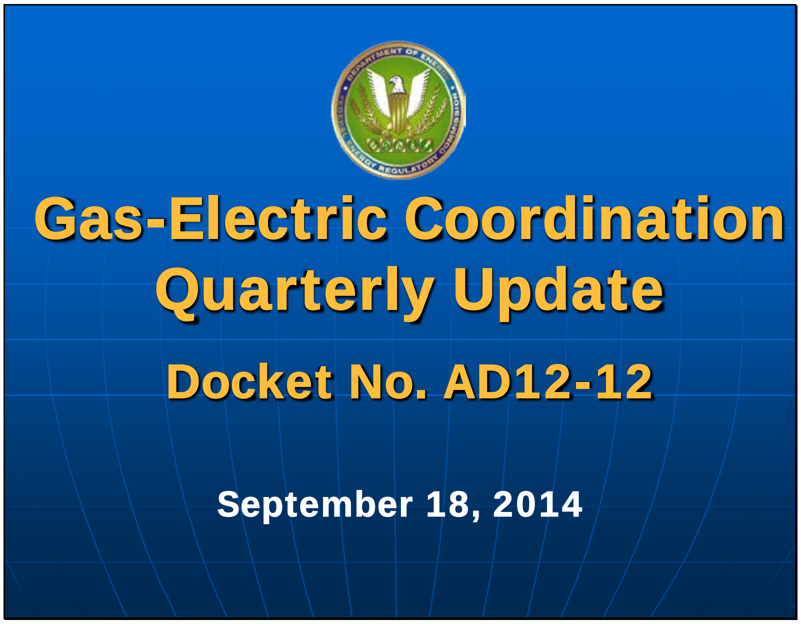
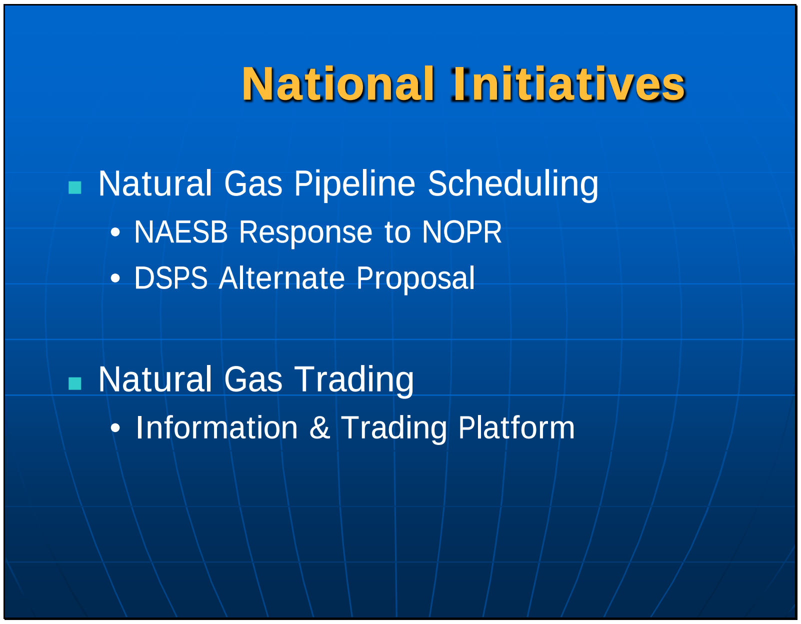
Gas-Electric Coordination Quarterly Report to the Commission

Docket No. AD12-12-000
September 18, 2014



This report is Commission staff's seventh quarterly update on national and regional Gas-Electric Coordination Activities, as directed by the Commission in its November 15, 2012 order in Docket No. AD12-12. This report covers the period June 2014 through September 2014.

This report focuses on significant new national and regional developments since last reported in June 2014, highlights the actions taken by the North American Energy Standards Board (NAESB) to support the directives in the March 20, 2014 Notice of Proposed Rulemaking (NOPR), and briefly summarizes recent industry applications filed with the Commission.



As noted in our last quarterly report, the North American Energy Standards Board (NAESB) Gas Electric Harmonization Forum in June concluded its consideration of the Commission's March 20, 2014 proposed rule to reform the scheduling processes of interstate natural gas pipelines (Docket No. RM14-2-000). While the Gas Electric Harmonization Forum was unable to achieve consensus on a complete package of alternatives to the Commission's proposals, the NAESB Board of Directors (Board) found that there was broad support in both the gas and electric industries for changes in the intraday scheduling cycles and day-ahead nomination cycles, and directed the Wholesale Gas Quadrant (WGQ) to develop new standards and modify existing standards to support these changes.

On June 18, 2014, NAESB submitted a report to the Commission to inform it of the Board's action and outline the additional steps NAESB intended to take. Since that report, the WGQ has developed new and revised standards in support of revised timelines for the timely, evening, intraday 1, intraday 2, and intraday 3 nomination cycles that received broad support in the Gas Electric Harmonization Forum. Specifically, the nomination deadline for the timely and evening cycles are the same as those proposed in the NOPR—1:00 pm Central Clock Time (Central) and 6:00 pm Central, respectively. The timelines for intraday 1, intraday 2, and intraday 3 vary from those proposed in the NOPR and the nomination deadlines would be at 10:00 am, 2:30 pm, and 7:00 pm, all Central time. The NAESB standards will not include an intraday 4 cycle nor any change to the Gas Day start time. The Gas Electric Harmonization Forum did not achieve broad support for such change.
These standards were posted for industry comment in July and August. On August 21, 2014, the WGQ Executive Committee met to consider the revised standards and the comments received. The Executive Committee voted on and passed the revised standards with a supermajority of both segments of the WGQ in support. On Friday, August 22, 2014 NAESB issued the standards for a 30 day period for ratification by the WGQ membership. NAESB is on schedule to file the standards with the Commission on September 29, 2014.

Arizona Public Service Company (APS) and Salt River Project Agricultural Improvement and Power District (SRP) voted in opposition to the standards at the NAESB WGQ Executive Committee. These entities, along with UNS Gas, Inc. and Tucson Electric Power Company, Public Service Company of New Mexico, El Paso Electric Company and the Arizona Corporation Commission – all of which are members of the Desert Southwest Pipeline Stakeholders (DSPS) – jointly submitted comments and an alternate (minority) proposal for inclusion in the NAESB record. DSPS presented a three-part proposal, two of which would apply on a national basis and one of which would apply on a regional basis. DSPS contends that this proposal would address the unique circumstances of the Desert Southwest (including the lack of storage in the region, the large growth in intermittent renewables in the region, and a peak period of demand between 5:00 pm and 7:00 pm local time).

First, DSPS proposes that the Commission would need to act on a national basis to move the nomination deadline for the NAESB Evening Cycle from 6:00 pm Central the day before the start of the next Gas Day to 7:00 pm Central. DSPS states that this change would provide an opportunity for shippers to request changes to their pipeline transportation service to address operational contingencies that occur in the period between 7:00 pm to 9:00 pm Central (5:00 and 7:00 pm local time). Second, DSPS proposes that the Commission act on a national basis to modify its policy on bumping during the NAESB Evening Cycle. Interstate natural gas pipelines schedule their systems based on the priority of the transportation contract held by the shipper. Nominations of capacity under firm transportation contracts from a primary receipt point to a primary delivery point (primary firm nominations) have the highest priority followed by secondary-firm nominations (which include at least one secondary receipt and/or delivery point). Currently, however, firm service (primary or secondary) scheduled in the Timely Nomination Cycle cannot be bumped by another firm nomination in subsequent nomination cycles. DSPS proposes that, in the NAESB Evening Cycle, primary-firm nominations should be permitted to displace or bump secondary-firm nominations previously scheduled during the Timely Nomination Cycle. DSPS states that this policy change would give primary-firm nominations a higher priority and increase their value, thereby encouraging long-term contracting and promoting infrastructure development.

Third, DSPS proposes that the Commission act on a regional basis to establish a 1-Year Pilot Program for pipelines serving the Desert Southwest that allows firm shippers to submit a separate retroactive, or make-up nomination during the Evening Cycle—which is currently utilized to make nominations for the following Gas Day. This proposal would allow a shipper, upon pipeline operator approval, to adjust its natural gas receipts or takes from the pipeline for the remainder of the current Gas Day, provided that the shipper submits a retroactive nomination during the Evening Cycle for the natural gas variance. Under such proposal, a shipper’s retroactive nomination and daily nomination cannot exceed the shipper's Maximum Daily Quantity. Furthermore, under the Pilot program, DSPS proposes that pipeline imbalance penalties only apply to imbalances that are not corrected at the start of the following Gas Day.

Separately, on August 19, the Commission issued a Notice announcing that Commissioner Phillip D. Moeller will convene a meeting on September 18, 2014 to discuss the concept of developing an electronic information and trading platform for natural gas. The purpose of the meeting is to provide a forum for interested parties to discuss ideas to facilitate and improve the way in which natural gas is traded, and explore the concept of establishing a centralized electronic trading platform that would include bids and offers for the purchase and sale of commodity and capacity for receipt and delivery points on and across multiple pipeline systems. The meeting will also discuss concerns regarding the lack of transparency and possible inefficiencies in trading the commodity, particularly during off-hours. The meeting will examine the current pipeline confirmation processes and how they might be accelerated, streamlined, and better coordinated across pipelines where necessary to support trading opportunities. The meeting is open to the public and all interested parties are invited to attend.

Work continues on interregional natural gas-electric studies conducted collaboratively by the ISOs/RTOs and the states.

The Eastern Interconnection Planning Collaborative (EIPC) is now working on the Target 2 study, which will evaluate the adequacy of the natural gas infrastructure in 2018 and 2023 to meet the expected core load and non-core gas-fired generation requirements on a Winter Peak Day and a Summer Peak Day. Work is focused on finalizing the second set of natural gas and electricity market assumptions on core and non-core demand levels such as infrastructure expansions, load growth, LDC expansion, and oil-to-gas conversion for Target 2 model inputs. The initial Target 2 draft report was posted on the EIPC website on June 20 and contains the methodology, inputs, and draft outline for the analysis of three demand scenarios and policy and infrastructure sensitivities. The High Gas Demand Scenario represents a "plausible maximum" level and profile of gas requirements driven primarily by increased deactivation or retirement of coal plants, lower delivered natural gas prices, and higher electric loads. The Low Gas Demand Scenario represents a "plausible minimum" level, driven primarily by the renewable resources displacement of gas-fired generation, higher delivered natural gas prices, and lower electric loads. The final Target 2 report is due in October 2014 and will provide complete analysis of possible infrastructure adequacy issues and propose potential mitigation measures. Target 3, on contingency analysis, and Target 4, on dual-fuel capability, are ongoing with discussions continuing through the Stakeholder Steering Committee. Northeastern ISOs and RTOs continue to work closely with representatives from the Planning Authorities in the Eastern Interconnection on the efforts of the EIPC study.

The ICF-led study on Long-term Electric and Natural Gas Infrastructure Requirements in the Eastern Interconnection, prepared for NARUC and the Eastern Interconnection States Planning Council (EISPC), examines the potential build-out of natural gas infrastructure required to supply power and gas customers to 2030 under three demand and policy scenarios for the power sector in the Eastern Interconnect region. The preliminary study results presented in September find that the overwhelming factor driving natural gas infrastructure development is the demand for electricity. The first scenario is the business-as-usual forecast for electric demand in the Eastern Interconnect from the present-day to 2030 based on existing policies and historical load growth. The second scenario forecasts the potential effects of policy-induced reductions in carbon emissions and electric demand from a national price on carbon, accelerated energy efficiency targets, and growing demand response options. The third scenario covers the potential effects from a renewable energy mandate in the Eastern Interconnect to satisfy at least 30 percent of electric load by 2030 with renewable energy resources. Findings from the study range from the highest total gas infrastructure costs by 2030 under the renewable energy scenario ($121.9 billion) to the lowest total costs under the policy-induced scenario ($83.3 billion). The ICF study anticipates that a majority of the infrastructure build-out will occur between 2014 and 2024, and that much of the capacity increases will take place in northeastern and southwestern states due to their proximity to large shale plays. Along with exploring costs, reliability, and resource adequacy in relation to fuel infrastructure and siting requirements, the study also investigates analytical methods for co-optimizing future capacity expansion in both industries, and finds that total infrastructure costs are lower when planners in both sectors collaborate, compared to when capacity expansion plans are developed separately. The study also provides a blueprint for how to account for natural gas and power sector needs together given non-coincident growth in demand for both natural gas and electricity. ICF is currently reviewing comment submissions, which were due August 15, 2014. The final draft of the ICF study is scheduled for release in November 2014. The EISPC will convene a full committee meeting in Washington D.C. on October 2-3, 2014. The objective of the two-day meeting is to increase understanding of and facilitate compliance in the Eastern Interconnection with the Clean Power Plan (EPA Section 111(d)).

On June 11, 2014, the New England States Committee on Electricity (NESCOE) issued a memorandum summarizing stakeholder input on several potential conceptual means to increase natural gas infrastructure in New England, including the Incremental Gas for Electric Reliability (IGER) concept reported last quarter. In addition, in the memorandum the New England states requested further information, by July 3, 2014, including: 1) expressions of interest from entities interested in acting as creditworthy counterparties to precedent agreements with natural gas pipeline companies, 2) further guidance on issues associated with the capacity manager role and/or indications of willingness to serve as a capacity manager and 3) input on other approaches and concepts that would increase natural gas infrastructure in New England in a way that delivers the highest value to electric customers.

On June 20, 2014 NESCOE provided an update to the New England Power Pool (NEPOOL) Transmission Committee on the Governor's Infrastructure Initiative. NESCOE stated that the New England states will seek NEPOOL support for two new schedules in the ISO-NE tariff that would serve to be the vehicle for billing and collection in support of transmission and natural gas pipeline infrastructure to advance power system reliability. NESCOE explained that the ISO-NE tariff schedule related to gas infrastructure, called the Regional Gas-Electric Reliability Service would not include information regarding the process to select a gas pipeline project(s) and that the final project(s) and costs will not be known before ISO-NE files this schedule with the Commission. The schedule is intended to be used for this one time Infrastructure Initiative only, not for generic or future use. NESCOE also stated that no agreement has been finalized by the New England states.

Specific to the IGER concept, NESCOE provided additional details in its update to NEPOOL. NESCOE explained that ISO-NE would enter into a Gas Infrastructure Billing and Collection Agreement with the entity or entities that act as counterparties with the pipeline(s) separate from, but in support of, the ISO-NE tariff schedule. The ISO-NE tariff schedule would allocate the costs of regional gas-electric reliability service to Regional Network Load. NESCOE stated that the charges would be pipeline and administrative costs less revenues received from capacity release. Since capacity release revenues will vary with market conditions, NESCOE expects the Regional Gas-Electric Reliability Service charge to vary over time. Subsequently, on July 21, 2014, NESCOE issued for discussion at the July 22, 2014 NEPOOL Transmission Committee Meeting, ISO-NE draft tariff language for billing and collection of gas infrastructure support charges.

While NESCOE expected NEPOOL to vote on the draft tariff language in August and September, on August 15, 2014, at the NEPOOL Participants Committee meeting, NESCOE requested an extension of the NEPOOL schedule for consideration of proposed tariff language in connection with the Governors' Infrastructure Initiative.

NYISO is continuing to sponsor meetings for discussion of the EIPC study and provides a forum for participants to discuss ongoing progress, sensitivity developments, and analysis.

The PJM Gas Electric Senior Task Force has been suspended until further notice. In preparation for winter 2014-2015, PJM determined that gas unit commitment issues are best addressed by the Operating Committee, where short-term adjustments to natural gas-fired generation scheduling can develop in tandem with cold-weather generation resource planning, capacity performance, and other operations-focused issues. The Operating Committee is conducting gas unit commitment coordination meetings to educate stakeholders on the balance between economic dispatch and reliability, and to achieve consensus on solutions to natural gas scheduling issues discovered during the cold weather events of winter 2013-2014. Some identified components for stakeholder discussion include new data collection requirements from generators, such as a "Latest Notification Time," a deadline for gas generator availability, and an associated "Price for the Latest Notification Time," which would inform the system operator of the offers available from gas units on an hourly basis in both the day-ahead and real-time market. Since the first gas unit commitment coordination meeting on June 23, 2014, the Operating Committee has developed a cold weather preparedness work plan, held high-level discussions on refining the PJM capacity performance definition, and hosted educational seminars on natural gas scheduling, coordination infrastructure, and market fundamentals.

In August, PJM staff began discussions with stakeholders regarding generator performance concerns. In a white paper issued on August 1, PJM staff stated that the events of winter 2014 operations highlighted issues related to generation performance, including a 22 percent forced outage rate on January 7, and increasing dependence on natural gas for power generation during winter peak conditions. PJM staff stated that the current requirements for resources to be considered a capacity resource do not appear to sufficiently address these observed generation performance issues, winter peak operations issues and operational characteristics that are needed to ensure that system reliability will be maintained going forward. PJM stated that the changing resource mix—due to the retirement of a large number of coal-fired resources being replaced by natural gas resources—is creating greater operational stress on the power system as the interactions between the commodity gas market and interstate pipeline scheduling are not yet harmonized with power market operation. In the white paper, PJM staff discussed its analysis to assess the system loss of load risk in each of the next two winters. The study results indicate that if Polar Vortex conditions occurred in 2015-2016 and outage rates were as high as PJM experienced in January, 2014, PJM would almost certainly experience a loss of load event.

Following this white paper, PJM staff issued a "capacity performance" proposal and subsequently met with stakeholders to receive feedback on the proposal. PJM is proposing to add a new enhanced product—Capacity Performance—to its capacity market to ensure that the reliability of the grid will be maintained as the resource mix changes. Under the proposal, resources eligible to provide the Capacity Performance product must be capable of sustained, predictable operation for 16 hours per day for three consecutive days throughout the year when PJM has declared a Hot Weather or Cold Weather Alert and/or declared a Maximum Emergency Generation Alert. To be eligible as a Capacity Performance resource, PJM is proposing that an officer of the generation resource's owner would have to certify that certain specific requirements—such as on-site or dual-fuel backup capability or a combination of firm pipeline transportation, firm commodity and access to storage or equivalent—have been met to ensure performance. PJM will not mandate how fuel availability is ensured, the decisions will be left to the individual resource owner on how to best manage fuel availability risks. PJM is using the Enhanced Liaison Committee Process, as opposed to the normal stakeholder process, to allow PJM and its members to develop solutions to this problem in time to be able to file its proposal to allow it to be in place by the winter of 2015.

MISO recently announced two initiatives aimed at improving real-time operational awareness for its operators and market participants following the experiences of the past winter. MISO created a natural gas pipeline notification page on its website, which is currently in the test phase and is scheduled to enter production by the end of September 2014. MISO is also working to implement a real time display of pipeline conditions in its control room.

In addition, MISO plans to develop a coordination and communication plan with natural gas pipelines in its footprint by October that will allow MISO to maintain better situational awareness of pipeline delivery capabilities and the operational status of pipelines within its region. The coordination and communication plan will include pipeline outage and maintenance reviews, a protocol for monthly updates, and a natural gas pipeline operating status such as active operational flow orders and non-public pipeline operational information.

Finally, MISO's Electric and Natural Gas Coordination Task Force completed an issue paper on "Continued Reliability through Market Signals" and made progress on the four issue papers the Task Force will pursue this year. Preliminary findings of the 2014 papers suggest MISO could have maintained grid reliability during the January 2014 Polar Vortex event without the amount of coal generation expected to retire by April 2016, even with substantial natural gas restrictions. The papers further find that interruptible natural gas pipeline service adequately met the needs of generation owners in the MISO region prior to January 2014, and that natural gas pipeline infrastructure in the MISO footprint is sufficient to serve planned natural gas-fired generation additions in the next several years. However, the papers state that continued reliability beyond the next several years may require generation owners' commitment to firm pipeline service contracts now, considering that the process to permit and construct new pipeline capacity may take up to three years.

The SPP Gas Electric Coordination Task Force issued a strawman proposal for changes to the SPP day-ahead market timeline during their July 31, 2014 meeting, and reviewed comments submitted by task force members and associated working groups regarding the proposed changes during their August 25, 2014 meeting. The proposed changes are based upon a revised NAESB Timely Nomination Cycle (Timely Cycle) deadline of 1:00 pm Central for scheduling interstate natural gas pipeline transportation and are as follows: 1) move the time when SPP operating reserve requirements are posted from 7:00 am Central to 5:00 am Central, and 2) move the bidding period deadline of the SPP day-ahead market earlier, from 11:00 am Central to 8:00 am Central. Stakeholders did not express concern with the proposal to post operating reserve requirements earlier in the day, but noted potential market and operation trade-offs with regard to moving the start of the bidding process of the day-ahead electric market before the nomination deadline for Timely Cycle. For example, some members were concerned that the compressed one-hour window between the end of the SPP day-ahead market bidding period and the deadline for scheduling pipeline transportation in the Timely Cycle presented purchasing and procurement difficulties for natural gas unless other issues were addressed, such as faster SPP market clearing processes. Other members, however, noted that more separation between the market clearing time and the operating day increased the potential for forecasting errors. The Gas Electric Coordination Task Force plans to continue discussion on comments to the strawman proposal at their next meeting on September 17, 2014.

SPP is currently developing a winter preparedness plan for winter 2014/15, which SPP anticipates implementing by December 1, 2014. This winter, SPP will act as the consolidated balancing authority for the region for the first time and will engage generators and pipeline operators in multiparty communications to better coordinate system operations and reliability during cold weather events. This effort builds upon SPP's winter 2013/14 role as an information coordinator between pipeline companies and power generators, during which SPP began developing multi-party communication protocols for sharing non-public information. SPP expects to complete these multi-party communication protocols by December 1, 2014.

In the West, there are a number of sub-regional natural gas-electric coordination initiatives.

In the third quarter, initial findings of Phase 2 of the Western Interstate Energy Board's (WIEB) Natural Gas–Electric and System Flexibility Assessment were released. Phase 2 evaluates the flexibility of the natural gas system and its ability to meet increased volatility in hourly electric demand with the increase of wind and solar resources in the Western Interconnection. The study subdivided the Western Interconnection into six sub-regional case studies to identify potential challenges. Phase 2 confirmed preliminary findings that physical infrastructure is generally adequate, and that such infrastructure is able to meet variable gas demands from increased integration of renewable resources comprising up to 26 percent of generation. Phase 2 found that increasing the penetration of renewable resources reduces the pipelines' flexibility capability even though the overall level of gas demand growth from the power generation sector is lower when renewable resource penetration is higher. In addition, the study found that the increase in variability from renewable resources increases the frequency and magnitude of imbalances on pipeline systems which could cause operational issues on the gas systems. The report finds that the potential challenges can be mitigated with more flexible natural gas transportation services that offer similar flexibility as is currently provided by natural gas storage and effective management of linepack. Members of the Pacific Northwest Utilities Conference Committee (PNUCC) Power and Natural Gas Planning Task Force reviewed and provided feedback on the study.

The full report is located on the WIEB website.(http://westernenergyboard.org/wp-content/uploads/2014/07/E3_WIEB_Ph2_Report_full_7-28-2014.pdf)

ColumbiaGrid will be performing a coal retirement study examining the transmission impacts of replacing coal units with natural gas. The study will include multiple scenarios in which the replacement gas units are sited in different parts of the Northwest. ColumbiaGrid plans to work in close coordination with natural gas entities to identify any interdependency concerns. A final study report is scheduled for December 2014.

On April 30, 2014 CAISO released an issue paper and straw proposal and initiated a stakeholder initiative to explore interim ISO tariff solutions to account for natural gas market conditions in minimum load and start-up costs. Currently, CAISO calculates the start-up and minimum load costs for resources under either a proxy cost or registered cost option selected by the resource. Under the proxy cost option, CAISO is required to rely on at least two natural gas price indices published the day prior to running the day-ahead market. CAISO proposes to retain the proxy cost option, but modify it to increase the proxy cost option bid cap from 100% of the daily calculated cost to 125%. CAISO states that this increase in the bid cap will provide flexibility to account for a variety of costs such as normal gas price volatility and the one day lag in the gas price indices used in the day-ahead market.

CAISO notes that the increased proxy cap will be effective on most days, but it would not be able to capture extreme price spikes. Therefore, CAISO proposes to retain a portion of the manual operations utilized last winter to update the natural gas price index using the single ICE index, the only one available the morning of the day-ahead market optimization. The manual process would be triggered when the natural gas price for any region is more than 125% of the natural gas price for that region from the previous night, which CAISO expects to be rare. CAISO would prefer a non-manual solution to correct for the lag in updating the gas price indices used in the optimization, but may not be able to implement one before the next winter season.

Under the registered cost option, the gas price is based on a monthly forward projection and is limited to no more than 150% of the projected proxy costs. Currently, resources selecting the registered cost option must remain under that option for at least 30 days. CAISO views the registered cost option as largely obsolete given the proposed improvements to the proxy cost option and proposes to limit its use.

CAISO anticipates bringing the proposal to the CAISO Board of Governors in mid-September, and implementing the proposed solutions prior to the 2014-2015 winter season to address the potential for high natural gas price spikes as occurred last winter. For more comprehensive, long-term solutions with greater implementation impacts, the CAISO expects to commence a bidding rules initiative in the third quarter of 2014. This future initiative will explore a broader array of bidding rules in the ISO market, including those for energy and commitment costs.

Relevant Natural Gas Filings

Region	Pipeline / Association	Capacity / Initiative	Docket No.	Status
Northeast	Transco Rock Springs Expansion Project	Capacity addition 192 MMcfd	CP14-504-000	Filed 6/23/2014
Southwest	Sierrita Gas Pipeline	Capacity addition 200 MMcfd	CP13-73 & 74	Under Construction 7/1/2014
Southeast	Colombia Pipeline	Capacity addition 1.12 Bcfd	CP14-513-000	Filed 7/1/2014
Northeast	Algonquin Salem Lateral Project	Capacity addition 115 MMcfd	CP14-522-000	Filed 7/10/2014
Northeast	Algonquin Incremental Market Project	Capacity addition 342 MMcfd	CP14-65-000	DEIS issued 8/6/2014
Northeast	Transco Woodbridge Delivery Lateral	Capacity addition 264 MMcfd	CP14-18-000	Approved 8/11/2014
Southeast	Southeast Supply Header Expansion Project	Capacity addition 45 MMcfd	CP14-87-000	Approved 8/14/2014
National	157 interstate natural gas pipelines	Order to Show Cause, Posting of Offers to Purchase Capacity	RP14-442-000	Pending
West	Transwestern Pipeline Company	Framing system balancing and operational issues	RP13-404-002	Approved
Mid-Atlantic	Transcontinental Gas Pipe Line Company	Order No. 787 on No-Conduit Rule	RP14-623-000	Approved
Northeast	National Fuel Gas Supply Corporation and Empire Pipeline	Request for Rehearing Regarding Limited Waivers of No-Conduit Rule adopted in Order No. 787	RP14-380-001	Pending

We now provide an update on relevant natural gas and electric filings submitted with or pending before the Commission, starting with natural gas pipeline applications. As discussed in more detail below, during this quarter the Commission received a new filing to expand pipeline capacity serving electric generation, approved two proposed projects, and received or acted on additional filings proposing enhanced services or tariff revisions to improve natural gas-electric coordination.

In the Northeast, on June 23, 2014, Transcontinental Gas Pipe Line Company, LLC (Transco) requested authorization to construct and operate its Rock Springs Expansion Project. This project will provide 192 MMcfd of firm transportation capacity to serve Old Dominion Electric Cooperative's proposed Wildcat Point Generating facility in Cecil County, Maryland.

In the Southeast, on June 6, 2014, Sierrita Gas Pipeline, LLC (Sierrita) received its Presidential permit to construct and operate new border crossing facilities for exporting natural gas to Mexico, and was also certificated to transport approximately 200 MMcfd. After receiving its initial construction commencement approval on July 1, Sierrita began construction to serve growing natural gas demand from power generation in Mexico and is working on its final segment to the pipeline terminus at the border with Mexico. Sierrita proposes to place the facilities in service in September 2014.

Additionally, on July 1, 2014, Colombia Pipeline, LLC (Colombia) filed an application for an order authorizing the siting, connection, construction, and operation of new border crossing pipeline facilities to export up to 1.12 Bcfd of natural gas at the International Boundary between the United States and Mexico in Webb County, Texas, and for a Presidential Permit for such facilities. At the International Border, a 0.48-mile pipeline on the México side will be constructed which will redeliver natural gas supplies into the pipeline system to a proposed power plant to be constructed near Colombia, Nuevo León, México.

On July 10, 2014, Algonquin Gas Transmission, LLC (Algonquin) filed an application for authority to construct, and operate its Salem Lateral Project located in Salem, Massachusetts. The proposed 1.2-mile Salem Lateral would provide 115 MMcfd of firm transportation service to the Salem Harbor Station facility being converted from coal to natural gas by June 2016.

On August 6, 2014, Algonquin Gas Transmission, LLC (Algonquin) Incremental Market Project (AIM Project) received its draft Environmental Impact Statement. The AIM Project will provide a total of 342 MMcfd of firm transportation service. Algonquin has executed Precedent Agreements for all of the capacity with ten shippers, including eight New England local distribution companies (LDCs) and two municipal utilities. The AIM Project, targeted for a 2016 in-service date, is expected to alleviate, in part, existing constraints resulting in increased commodity price competition and reduced natural gas price volatility in the Northeast markets.

On August 11, 2014, Transco was granted a certificate of public convenience and necessity to construct and operate approximately 2.4 miles of 20-inch diameter pipeline and associated facilities in Middlesex County, New Jersey, the Woodbridge Delivery Lateral Project. The Project will enable Transco to provide 264 MMcfd of incremental firm transportation service to the Woodbridge Energy Center, an electric generating facility being developed in Woodbridge, New Jersey.

On August 14, 2014, Southeast Supply Header, LLC received approval for its Expansion Project to increase the design capacity of its mainline to provide an additional 45 MMcfd of firm transportation service and to construct and operate a new booster compressor station facilities in Copiah County, Mississippi. Southern Company Services, Inc. executed a precedent agreement for 25 MMcfd of firm transportation service for a primary term of approximately 10 years to serve its natural gas-fired generation needs.

Since last quarter, 10 additional interstate natural gas pipelines, now totaling 157, submitted filings to the Commission in response to the Commission's March 20, 2014 order establishing a Natural Gas Act (NGA) section 5 show cause proceeding requiring all interstate natural gas pipelines to revise their tariffs to provide for the posting of offers to purchase released pipeline capacity in compliance with section 284.8(d) of the Commission's regulations, or to otherwise demonstrate full compliance with the Commission's regulation. This matter is pending before the Commission.

On June 23, 2014, the Commission approved a settlement filed by Transwestern Pipeline Company, LLC (Transwestern). The settlement includes a Scheduling Protocol providing enhanced daily scheduling and gas balancing flexibility for electric generators and other shippers on the Transwestern system. The Protocol provides that firm shippers that nominate inside the path in the Timely cycle are able to schedule those nominated quantities until the Evening cycle regardless of whether the full nomination is confirmed or scheduled during the Timely cycle. To allow additional time to secure supplies without the risk of losing capacity priority at the delivery area, the Protocol allows for firm shippers to nominate during the Timely and Evening cycles at five newly created Balancing Receipt Points.

On August 18, 2014, the Commission issued an order in Docket No. RP14-623-000 granting Transco's requested waiver to allow employees shared by Transco and its affiliated intrastate pipeline to receive non-public, operational information under Order No. 787, subject to conditions.

Following the Commission's June 19, 2014 order granting in part and denying in part National Fuel Pipelines' request for waivers of Order No. 787 in Docket No. RP14-380-000, on July 21, 2014, National Fuel Pipelines filed a request for rehearing. Specifically, National Fuel Pipelines argue that the Commissions should (1) permit non-shared employees of National Fuel Pipelines' affiliates to receive information about power interruptions to their places of work; and (2) permit Midstream employees to receive information about power interruptions to Midstream facilities. These filings are pending before the Commission.

Relevant Electric Filings

Entity	Filing Initiative	Docket No.
PJM	Pipeline Information-Sharing Changes under Order No. 787	ER14-1469-001
National Fuel	Request for Rehearing	ER14-1469-002
National Fuel	Motion for Clarification	RM13-17-002
Old Dominion Electric Cooperative	Waiver Request	ER14-2242
ISO-NE and NEPOOL	Rule Changes as part of the 2014-2015 Winter Reliability Program	ER14-2407-000 and ER14-2407-001

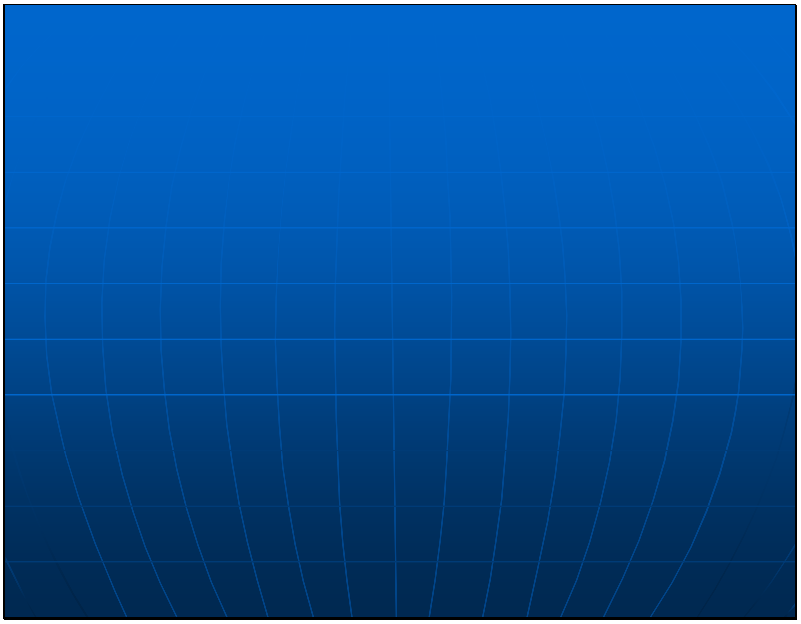
Turning to relevant electric filings, as reported last quarter, on May 9, 2014, the Commission accepted, subject to conditions, PJM's proposed tariff revisions to modify the confidentiality rules to allow PJM to share non-public, operational information with natural gas pipeline operators, consistent with the Commission's regulations adopted in Order No. 787. However, the May 9 Order also required PJM to resubmit tariff records and specify which local distribution or intrastate pipeline employees will be prohibited from receiving non-public, operational information. On May 27, 2014, PJM filed a revised tariff record in Docket No. ER14-1469-001 to require that a recipient LDC or intrastate pipeline operator acknowledge, in writing, that it shall not disclose, or use anyone as a conduit for disclosure of, non-public, operational information received from PJM to a third party or in an unduly discriminatory or preferential manner or to the detriment of any natural gas or electric market. On July 16, 2014, the proposal was accepted for filing by delegated order, effective March 13, 2014.

On August 15, 2014, National Fuel Gas Distribution Corporation (National Fuel) submitted a Motion for Clarification or, in the Alternative, Request for Rehearing of the Commission's May 9, 2014 and July 16, 2014 Letter Orders in Docket No. ER14-1469 discussed above. National Fuel states that PJM's revised tariff language may inhibit appropriate sharing of operational data and discourage LDCs and intrastate pipelines from maximizing use of the data to improve reliability. This matter is pending before the Commission.

On August 27, 2014, National Fuel also submitted, in Docket No. RM13-17-002, a Motion for Clarification of Order No. 787, the Commission's Final Rule regarding Communication of Operational Information Between Natural Gas Pipelines and Electric Transmission Operators, and Order No. 787-A, the Commission's Order on Rehearing. National Fuel requests the clarification to provide further guidance regarding implementation of the Final Rule and ensure that the Commission's stated goals in the Final Rule are uniformly carried out and met to the fullest extent. This matter is pending before the Commission.

On June 23, 2014, Old Dominion Electric Cooperative (ODEC) filed a request for waiver of certain provisions of PJM's tariff and Operating Agreement in Docket No. ER14-2242 to make ODEC whole for natural gas costs it incurred in January 2014 in its efforts to meet dispatch instructions issued by PJM. This matter is pending before the Commission.

On July 11, 2014, ISO-NE filed a package of rule changes in Docket Nos. ER14-2407-000 and ER14-2407-001 that establish a 2014-2015 Winter Reliability Program. While similar to the 2013-2014 Winter Reliability Program previously accepted by the Commission, several components of the proposed 2014-2015 Program differ. The package is comprised of six components, two of which are permanent changes while the other four are temporary changes to be in place for this winter. According to ISO-NE, one of the permanent rule changes will enhance ISO-NE's ability to audit dual fuel resources. The second permanent rule change will adjust the market monitoring provisions to remove impediments for dual fuel resources which have cleared in the day-ahead market based upon one fuel, but may wish to burn the other fuel during the operating day. In addition, ISO-NE proposes to include LNG supplies in the 2014-2015 Winter Reliability Program, along with oil-fired, dual fuel, and demand response resources, all of which were included in the 2013-2014 program. ISO-NE also proposes to change the compensation for oil inventory for the 2014-2015 Program from last winter's Reliability Program. In contrast to 2013-2014 program, where ISO-NE compensated resources for the fuel inventory procured ahead of the winter, ISO-NE proposes to compensate resources this winter for their unused fuel inventory measured at the end of the season, March 15, 2015. ISO-NE proposes to allocate the costs of the 2014-2015 program to Real Time Load Obligation. On September 9, 2014, the Commission accepted ISO-NE's 2014-2015 Winter Reliability Program for filing, with the proposed tariff revisions regarding dual fuel capability, unused fuel inventory, market monitoring, and demand response to become effective September 9, 2014, as requested, and the tariff revisions regarding market monitoring to become effective December 3, 2014 as requested. However, the Commission required ISO-NE to initiate a stakeholder process by January 1, 2015 to develop a proposal to address reliability concerns for the 2015-2016 winter and future winters, as necessary, and submit informational progress reports. The Commission also directed ISO-NE to include certain analysis and recommendations as part of the Internal Market Monitor's Annual Markets Report.



Staff's final quarterly report is due in December.