UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Coordination between Natural Gas and Electricity Markets	**Docket No. AD12-12-000**

Responses of the California Independent System Operator Corporation to Questions Regarding Electric and Natural Gas Industry Coordination and Communication

The California Independent System Operator Corporation (ISO) submits these written responses to the questions issued by Commissioner Moeller on June 4, 2013 in connection with the above-captioned proceeding.

<u>Question 1</u>

Many ISO/RTOs have ongoing stakeholder processes looking at various issues associated with gas-electric coordination issues. What are the specific recommendations emerging that can be implemented quickly (e.g., by January 2014), for example, without requiring expensive and time-consuming software changes, while stakeholders are evaluating longer-term solutions? Please explain whether these require tariff changes.

<u>Response</u>

The ISO has enhanced its coordination activities with gas pipelines over the last several years. The ISO is coordinating maintenance outages on the electric and gas systems; examining potential infrastructure development; refining operational practices, and resolving real time operations issues as they arise. The ISO is implementing these practices now. It does not require additional tariff authority to do so.

In summary, the ISO confers with gas pipelines operators on at least a quarterly basis. These meetings include a discussion of available gas inventory, projected supplies, planned maintenance work on gas facilities, upcoming additions to the gas system, outages that could impact the availability or capacity of gas-fired generation, and long-range weather forecasts. The ISO meets with gas pipeline operators in advance of the ISO's summer peak season and also in the fall to determine the winter assessment for fuel capabilities of gas-fired generation and related outages.

Communications between the ISO and gas pipeline operators also occur on a daily and real-time basis as needed. Each day the ISO sends to major gas pipeline operators the aggregate burn rate per hour for each company based on the day-ahead market results of gas-fired generation. Real-time discussions predominantly focus on more immediate operational concerns, such as:

- Changes to the electric grid that occur if the day ahead load forecast changes after the day-ahead market results are published;
- An unplanned outage of a generating facility that results in a need for additional gas-fired generation after the day-ahead market results are published;
- A weather forecast of extreme conditions in the form of either a heat wave or cold spell;
- An unplanned outage of major gas pipeline facilities that could impact gas supply and affect the capacity or availability of gas-fired generation; and
- Local supply issues when gas turbine units are dispatched and remain on-line for extended periods of time.

The ISO also shares outage information with affected natural gas pipeline operators to help manage ongoing natural gas pipeline testing and maintenance. The Commission has already authorized the ISO to share this information subject to applicable nondisclosure and use limitation requirements.[1] This practice assists the ISO's efforts to coordinate operations and outages during a period in which pipelines are undertaking pressure testing of their natural gas facilities. The ISO has adopted an operating procedure to help guide the roles, communications and actions of ISO personnel related to natural gas transmission reductions or curtailments and impacts to the electric system in immediate and planned timeframes.[2]

Beyond these activities, the ISO is working with gas pipelines to explore whether changes to gas nomination schedules are necessary or appropriate to accommodate electric system operations. While a "single energy day" appears unnecessary in California, as discussed in response to Question 2, the ISO and stakeholders continue to assess if regional changes can enhance the robust gas-electric coordination that already exists.

The ISO will make its renewable integration studies available to other electric and gas industry participants, including the Western Governors Association's Western Interstate Energy Board (WIEB). As part of its Western Gas-Electric Regional Assessment project, WIEB will assess the adequacy of gas infrastructure and operational flexibility to meet long-term needs of the industry in the Western Interconnection. The WIEB studies will provide a more detailed assessment of whether adequate gas infrastructure exists to meet the needs required by high levels of renewables. The ISO does not believe it needs to amend its tariff to continue to participate in these activities.

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1 *Cal. Indep. Sys. Operator Corp.*, December 8, 2011 Letter Order Accepting Tariff Revisions to Permit Outage Information Sharing with Natural Gas Pipelines in Docket ER12-278. http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=12834374

2 Operating Procedure 4120 http://www.caiso.com/Documents/4120.pdf

Question 2

Some of the challenges associated with gas-electric coordination occur when gas-fired generators are asked to obtain gas supply and pipeline transportation capacity, or additional gas supply and pipeline transportation capacity, on short notice or outside of the normal day-ahead nomination cycles. Is your ISO/RTO exploring ways to improve the day-ahead scheduling process to better reflect the expected real-time generation requirements? Are there "best practices" in this area that each ISO/RTO should be considering? ISO-NE recently implemented changes to its day-ahead schedule to better align the gas and electric trading days. Is your ISO/RTO considering similar modification for bidding and clearing in the day-ahead market?

Response

At this time, the ISO is not considering changes to the process for bidding or clearing awards in its day-ahead electric market for purposes of aligning those processes with the market timeline for gas nominations. The ISO's market clearing process and the nomination cycles for pipeline operators serving gas-fired generators in the ISO's balancing authority area are already well aligned. The ISO believes this alignment provides gas-fired generators with sufficient flexibility and tools to obtain needed fuel.

The ISO's day-ahead market determines hourly market-clearing prices and unit commitments, analyzes unit must-run needs and mitigates bids if necessary, which produces the least cost energy while meeting reliability needs. The market opens seven days prior to the trade date and closes at 10:00 a.m. the day before the trade date. Results are generally published at 1:00 p.m. and include financially binding energy and ancillary service awards. This schedule aligns well with the day-ahead gas nomination cycle of pipeline operators serving gas-fired generation within the ISO's balancing authority area. Gas-fired generators may nominate pipeline capacity multiple times each day, up to the day prior to an electric trade date. On the day before a trade day, gas fired generators may nominate gas pipeline capacity at 9:30 a.m., before the 10:00 a.m. deadline to submit day-head energy schedules.

After the close of the ISO's day ahead market, gas fired generators may again nominate for additional (or reduced, as appropriate) gas supply and pipeline capacity at 4:00 p.m., for the next trade date. Additionally, generators may arrange for an injection into or withdrawal from previously secured storage facilities or a change in the injection/withdrawal rate. During a trade day, moreover, gas-fired generators can procure additional balancing services from pipeline operators and submit economic bids in the ISO's real-time market.

When a scheduling coordinator submits bids on behalf of a gas-fired generator into the ISO's market and receives an award for that resource, the scheduling coordinator assumes financial responsibility for that award.[3] This financial responsibility encompasses the obligation to secure necessary fuel and fuel transportation services to support the resource's scheduled output. Notwithstanding the above, the ISO is currently preparing a tariff amendment to allow gas fired generators to recover gas pipeline penalties through the ISO's bid cost recovery mechanism under a certain narrow circumstance - only when, on days gas resources are subject to financial penalties, the ISO needs the resource but the resource is unable to nominate gas supplies to fulfill the ISO requirement. Bid cost recovery is a mechanism for recovering costs from the ISO when market revenues are insufficient.[4]

The ISO is mindful of the importance of maintaining the reliability of the natural gas system and the fact that the reliability of the electric system is in part dependent upon the reliability of the natural gas system. One of the tools that gas

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[3] ISO tariff Section 4.5.3.12. "Each Scheduling Coordinator shall be responsible for: assuming financial responsibility for all Schedules, awards, HASP Intertie Schedules and Dispatch Instructions issued in the CAISO Markets, and all Virtual Bids in accordance with the provisions of this [tariff.]"

[4] More information on this initiative is available at the following website: http://www.caiso.com/informed/Pages/StakeholderProcesses/CommitmentCostsRefinement2012.aspx?ForceRefresh=1

pipeline operators utilize for doing so is to impose penalties on gas customers that under- or over-consume their entitlements on the gas system. The ISO's core mission, however, is to maintain the reliability of the ISO grid. Accordingly, the ISO believes this tariff amendment strikes an appropriate balance between ensuring reliable gas system operations and electric reliability by limiting the recovery of penalties only to those resources needed for reliability of the electricity system. The ISO expects to file this tariff amendment with the Commission in the third quarter of 2013, and implement the bid cost recovery refinements as part of its fall 2013 market release.

Question 3

What are the specific concerns that your region has for this coming winter? Are there specific actions the Commission can take to help address those concerns?

Response

Looking forward to this coming winter, the most pressing concern for gas and electric coordination in the ISO's balancing authority is outage coordination. Outage coordination proves challenging during winter because the ISO is a summer peaking balancing authority. As a result, planned outages for electric infrastructure occur in other seasons (i.e. during months in which there is the least demand for electricity). During the 2012-2013 winter, the ISO processed literally thousands of outage requests per month. Fortunately, the Commission has provided the ISO with sufficient authority to coordinate these activities with gas pipeline operators.

The ISO will use shoulder months to schedule inspection and maintenance of transmission and generator facilities. Gas pipeline operators will do the same to inspect and maintain their own facilities. This effort will require ongoing communications and planning between the ISO and gas pipeline operators.

On a localized level, the ISO is coordinating with San Diego for additional pipeline inspections this fall. The shut-down of units 2 and 3 at San Onfore Nuclear Generating Station is expected to increase the use of gas-fired generation in Southern California. This situation underscores the need for the high level of coordination for the southern California area, especially in San Diego. The ISO has already started coordinating with San Diego Gas & Electric (SDG&E) to facilitate pipeline outages during the fourth quarter of 2013 to avoid scheduling co-incident electric transmission outages so as to ensure maximum import capabilities in to the San Diego area while gas pipelines are out of service.

Additionally, the ISO expects that both electric and gas loads will peak in Humboldt County during the winter. Humboldt is a transmission constrained area, so ongoing coordination, as already exists, is necessary to ensure sufficient fuel exists to operate gas-fired generation to support electric loads in that area.

Question 4

There has been some discussion about shifting the start of the gas operating day ahead of the electric morning ramp. Would such a change improve gas-electric coordination in your region?

Response

The ISO does not believe shifting the start of the gas operating day ahead of the electric morning ramp will necessarily result in improved coordination, efficiency or reliability. As explained in response to Question 3, the ISO's market and the gas day for pipeline operators serving gas-fired generation that participate in the ISO's market are generally aligned and provide needed flexibility. Additional changes may not result in any incremental benefits and could cause unintended negative consequences.

Based on the ISO's ongoing discussions with stakeholders and pipeline operators, the ISO understands that, for example, changing the start of the gas day to an earlier hour may change application of the "elapsed pro-rata rule." The elapsed pro-rata rule standardizes how gas flows are deemed to occur ratably across 24 hours. Starting the gas-day two hours earlier (i.e. at 5:00 a.m. Pacific Time rather than 7:00 a.m.) will reduce the flexibility to adjust flows later in the day, thereby reducing the flexibility that may be needed later in the day to accommodate the afternoon burn associated with California's daily electrical peak. Late cycle nominations are already subject to limitations from elapsed pro-rata rules, so an earlier start to the gas-day could constrain late cycle nominations even more. Moreover, changing the timing of the ISO's complex day-ahead market will have myriad repercussions as many electricity-scheduling systems throughout the Western Interconnection are designed around the ISO's day-ahead market. In sum, so long as the gas nomination cycles remain well coordinated with electricity scheduling, a "single energy day" would not provide any incremental benefit and is, therefore, unnecessary.

<u>Question 5</u>

Are gas system contingencies included in your ISO/RTO system planning? If so, what are they, how were they selected and how often are they updated?

<u>Response</u>

With respect to a planning horizon (as opposed to an operational horizon), the ISO does not explicitly include gas system contingencies in its system planning. By considering the loss of electrical generation in transmission constrained areas, the ISO's planning decisions implicitly include the loss of a fuel source as a potential cause for a loss of electrical generation.

Within the transmission planning (TPL) reliability standards, the loss of a single generator is considered a single contingency event.[5] Extreme contingencies, however, consider the loss of all generating units at a station.[6] An outage to the gas system may affect the supply to multiple generation units at more than one station within an area.

Before adopting a gas system contingency as an explicit planning assumption, the industry would need to assess what level of planning criteria equates to the loss of a gas pipeline. Would this reflect a single contingency event or an extreme event? The ISO expects that the electric industry would need to develop significant expertise and collaborative planning strategies regarding gas system operations before making any such planning decisions. In some cases, the loss of a gas pipeline may cause the immediate loss of generation. In other cases, the loss of a gas pipeline may not create instantaneous impacts on the electric system because the line pressure may sustain electric generation facilities for sufficient time to re-dispatch the system.

The ISO believes that any consideration of whether a gas system contingency is a reasonable planning assumption should require an assessment of the likelihood and impact that gas system events have impacted electric grid conditions with a specific region. Electric systems are currently planned and constructed to meet existing reliability standards, and in some transmission constrained areas are at or very near reliability requirements with very little margin. Imposing a different planning contingency without enabling prior infrastructure development could create requirements that cannot be met until electric and gas infrastructure can be planned,

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5 *See* TPL-002 – System Performance Following Loss of a Single Bulk Electric System Element - Category B.

6 *See* TPL-004 – System Performance Following Extreme BES Events - Category D.

built and operated to the new requirements. The cost impacts of any such action could be significant. Collaborative planning strategies regarding gas system operations, and a careful assessment of the likelihood and impact of potential gas system events, would be a valuable precursor to determining whether gas system contingencies should be included in electric system planning.

Question 6

What specific steps is your region taking to improve situational awareness of local conditions, such as planned or unplanned maintenance of natural gas pipelines? Are these steps on track to be implemented before the next winter heating season? What actions should the Commission consider taking to facilitate improvements in this area?

Response

As stated in response to Question 1, the ISO has adopted operating procedure 4120 to guide the roles, communications and actions of ISO personnel related to natural gas transmission reductions or curtailments and impacts to the electric system in immediate and planned timeframes.[7] The procedure highlights the importance of coordination activities across ISO departments and with external entities in connection with both planned and unplanned gas outages systems that have California power plants as end-users. The ISO has implemented this procedure and believes that these practices have improved the situational awareness for both ISO operators and gas pipeline operators.

While the ISO's practices and procedures have contributed to successful coordination with gas pipeline operators, the ISO cautions against developing a standard procedure applicable to all entities and all situations because the exact nature of electric and natural gas coordination may be fact-specific. For instance, during the fall of 2011, the ISO and Southern California Gas Company successfully

[7] Operating Procedure 4120 http://www.caiso.com/Documents/4120.pdf

coordinated pipeline inspection work that required a maximum amount of flexibility. This work involved timing pipeline inspections over weekend days and issuing exceptional dispatches well in advance of the trading day to ensure that the generators identified by the ISO as necessary could obtain fuel from alternative pipelines. The ISO created procedures uniquely for this event that would not be generally applicable to other gas pipeline interruptions. Any action the Commission may take before next winter should not create mandatory requirements but should instead provide electric and gas system operators as much flexibility as possible to tailor their coordination activities to the specific facts they may face.

Dated: July 2, 2013

Respectfully submitted,

By: *<u>/s/ Andrew Ulmer</u>*

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CERTIFICATE OF SERVICE

I hereby certify that I have served the foregoing document upon all of the parties listed on the official service lists for the above referenced proceedings, in accordance with the requirements of Rule 2010 of the Commission's Rules of Practice and Procedure (18 C.F.R. § 385.2011).

Dated at Folsom, California this 2nd day of July 2013.

/s/ Anna Pascuzzo

Anna Pascuzzo