Shell Energy North America - Comments ISO Proposal for Alignment of RTO DA Scheduling Process with new Timely Gas Nomination Cycle at 11 a.m. PPT per FERC order 809

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Shell Energy appreciates the opportunity to provide comments to the April 22, 2015 Bidding Rules Enhancements Straw Proposal and the ISO stakeholder call on April 29, 2015. The ISO has requested an expedited schedule regarding comments to the FERC Order 809 and the change of the gas Timely nomination cycle from 9:30 a.m. PPT to 11:00 a.m. PPT. The ISO seeks comments on May 6, with a stakeholder call on May 15 and a second round of comments on May 27.

The FERC order instructs RTOs to align their day-ahead scheduling with the revised natural gas scheduling process or show cause as to why its scheduling processes do not need to be changed. The ISO has requested input from stakeholders on potential scenarios for compliance.

In accordance with FERC order 809, FERC must determine whether the ISO or RTO's day-ahead scheduling is just and reasonable, requiring the RTO to either file tariff changes to adjust the time at which the results of its day-ahead energy market commitment process are posted that is sufficiently in advance of the Timely and Evening Nomination Cycles to allow gas-fired generators to procure natural gas supply and pipeline transportation capacity, or to show cause why such changes are not necessary. Each ISO or RTO must explain how its proposed scheduling modifications are sufficient for gas-fired generators to secure gas supply prior to the Timely and Evening Nomination cycles.

Overview of Current Process:

Currently gas and power are procured in bilateral markets between approximately 5:30 a.m. and 6:30 a.m. Gas procurement continues beyond 6:30 a.m., although at a much lower quantity, as gas trades are then provided to the gas schedulers to schedule on the pipelines by 9:30 a.m. for the current Timely cycle. Once schedules are submitted, the DA trading process is informally considered completed, and ICE publishes a daily gas index at 10 a.m.

Daily at 5:30 a.m. PPT, generator owners ("Suppliers") must estimate the CAISO DA dispatch for the generation facilities they manage, and purchase gas to meet an anticipated CAISO dispatch. They may sell power as a hedge, and may then self-schedule, particularly if it is difficult or costly to curtail the gas.

The CAISO accepts DA supply bids at 10 a.m. and IST schedules at 11 a.m. The CAISO then issues DA energy schedules at 1 p.m., and after the schedules are issued, a Supplier must then manage any quantity misalignment of gas procured and previously scheduled in the Timely cycle with its new CAISO DA energy schedule. Suppliers must manage these imbalances through intraday gas sales and Local Distribution Company/Pipeline ("LDC") balancing rules. Intraday trading is generally scheduled during the Evening Cycle at 4:00 p.m. PPT, or the Intraday (same day) scheduling cycles, ID 1 and ID2 at 8:00

a.m. and 3:00 p.m. PPT. Under Order 809, a new ID3 cycle at 5 p.m. is added. Suppliers have price risk between DA and intraday when re-adjusting gas procurement to match the CAISO dispatch.

The CAISO has proposed the following 3 alternatives to respond to FERC Order 809:

Alternative 1 – Move DA market timeline to 7 a.m. to 10 a.m.

Alternative 2 – Keep current DA market timeline from 10 a.m. to 1 p.m.

Alternative 3 – Move the DA market timeline to 12:00 p.m. to 3:00 p.m.

The CAISO has provided the following questions to begin the discussion of the alternatives.

1. How much gas do you procure through the Timely market? How would that change with the new nomination deadline? Does the deadline impact operations (e.g., leads to more self-scheduling or less economic bidding in the real-time)?

Gas is procured daily during the gas and power bilateral trading that occurs at 5:30 a.m. PPT. Quantities vary depending on how much capacity is economic in the bilateral power market and self-scheduling is dependent on arrangements to curtail gas at the well head or otherwise manage imbalances should the ISO actual dispatch be different from the dispatch schedule that has been estimated. Generally, all the gas traded prior to 9:30 a.m. is scheduled in the Timely nomination cycle.

With the new nomination cycle deadline changing from 9:30 a.m. to 11:00 a.m., and no change to the ISO's DA market timeline, no real change is anticipated. The ISO would issue DA schedules after the Timely nomination cycle, and the current need to use the intraday gas market would continue.

If the ISO adopted Alternate 1, then it is likely that gas procurement would be split, and "true-up" gas would be traded after ISO schedules are issued and before the Timely nomination cycle, between 10 and 11 a.m. Successful implementation of Alternate 1 is also dependent on whether gas pricing will move over the morning, and when ICE will publish daily indices, and the ISO may need to retain a tolerance on gas pricing to ensure adequate cost recovery.

The new Timely nomination deadline affects the gas operations staff associated with scheduling, and an earlier CAISO market timeline could affect the bilateral markets, compressing the time to schedule economic bilateral power into CAISO markets (the bilateral markets would likely conclude at 6:30 a.m. and SC's would set up and submit DA bids to the ISO between 6:30 a.m. and 7:00 a.m.).

2. Are the 3 alternatives appropriate and viable for market participants? Are there more alternatives?

Alternative 1 – Move DA market timeline to 7 a.m. to 10 a.m. (before the Timely cycle)

Alternative 2 – Keep current DA market timeline from 10 a.m. to 1 p.m. (similar scheduling issues as are experienced today)

Alternative 3 – Move the DA market timeline to 12:00 p.m. to 3:00 p.m. (effectively similar to Alt. 2, but allows VERs to possibly improve their DA forecast)

While each alternative is technically viable, they may not be appropriate if the objective is to reduce cost to consumers. We do not envision other alternatives.

The ISO's objective should be to assign risk to the entity which can best effectively manage the risk. The question of whether an alternative is viable should be how it reduces risk that will lower the overall cost of energy to consumers. Alternative 1 can reduce the risk premium for gas quantity, and better align volume with ISO DA dispatch schedules, reducing the risk premium for volumetric uncertainty.

Alternate 1 may also reduce price risk, but this is yet to be determined, and will evolve as nationwide gas trading may either trade at the same time, or may extend up to the new Timely nomination cycle. As price risk must still be managed, even under Alternate 1, and as there is no mechanism to ensure that there will not be price differentiation during the gas trading period, the CAISO needs to ensure cost recovery for Suppliers. Consumers would be best served in an "as-bid" pricing structure, in which Suppliers provide a bid to sell energy (as a normal market would operate), and are mitigated if they have market power. Alternatively, the ISO could retain a tolerance band on the gas price. The issue as to which Alternate should be chosen becomes a question of which results in the most efficient market, or that which assigns risk to the entity that can best manage the risk while reducing overall cost to consumers. It would appear that being able to procure gas during the ISO market timeline, with a Supplier able to buy some of its anticipated gas during the normal daily trading process, and then to be able to true up its gas requirements after ISO DA schedules are issued would result in the ability to procure DA gas quantities much more accurately and potentially at or near DA gas index prices. Further, the gas scheduled in the gas pipeline system would more accurately reflect the CAISO DA dispatch system wide. This can also result in reducing power plant caused OFOs and imbalances. The objective should be to move risk to the entity that can best manage it.

Further, it appears from the FERC order that there is an intent to ensure that more gas is accurately scheduled in the Timely cycle and that the DA gas price is better reflected in both the commitment cost run and the economic dispatch run, as could be reflected in Alternate 1.

3. What are the benefits and concerns for each alternative? Please be explicit and describe both operational and financial impacts.

Alternative 1:

The FERC order changes the gas Timely nomination cycle from 9:30 a.m. PPT to 11:00 a.m. PPT. However, it does not address whether gas trading will still take place at the same time or whether most gas will trade concurrently with the bilateral power market at 5:30 a.m. PPT, or whether some gas trading will take place from 10:00 a.m. to 11:00 a.m., after the CAISO issues DA dispatch schedules. The market will develop, based on the new timely cycle and potential ISO changes. There may or may not be significant price changes between 5:30 a.m. and 11:00 a.m.

Alternative 1 would change the CAISO bid submission timeline from 10 a.m. to 7 a.m. for DA energy bids, and thus from 11 a.m. to 8 a.m. for interSC schedules and to 10 a.m. for issuing DA energy schedules. It is reasonable that bilateral gas and power trading would still take place from 5:30 a.m. to 6:30 a.m. PPT, and that some of a Supplier's anticipated gas requirements would be procured in this timeframe. Most DA bilateral and intertie trading would be completed by the anticipated 7 a.m. timeline for submission of DA bids to the CAISO. It is also reasonable that at 10 a.m. when the CAISO issues DA schedules, Suppliers could procure the balance of their gas needs or sell excess gas in the DA gas market, prior to the need to submit gas schedules on the new Timely nomination cycle at 11 a.m. This can provide better scheduling on the gas system, however, there will still be pricing risk, as there is no guarantee that the gas price will not change during the trading period prior to Timely. It would follow that ICE would likely publish gas indices at 11:30 a.m. which would be consistent with its publishing timeline today, at 30 minutes after the Timely cycle.

Benefits: In addition to the ability to procure quantities of gas according to the CAISO DA dispatch schedule, a Supplier could better minimize imbalance penalties and procure gas pipeline transportation capacity in quantities that better reflect the actual DA dispatch schedule. As LDCs introduce more onerous gas balancing requirements (and penalties) and potentially move to ratable flow, or potentially hourly or block flows, the ability to procure gas in a more granular (hourly) fashion will better align gas and energy prices and reduce scheduling and imbalance risk and potentially excess costs for Suppliers, and ultimately consumers.

It is also important that the CAISO recognize that there must be some provision to accommodate gas cost run up (differences in gas costs from index during the trading period) and to continue to consider that Suppliers may offer energy at a bid price, and the CAISO and/or load may or may not choose to procure it. This is an important distinction, as a Supplier needs to recover its operating costs, and the CAISO rules need to accommodate bids. There are two constructs that the ISO may consider. The competitive solution is to allow Suppliers to provide a bid for energy and for the CAISO to impose market power mitigation measures when, through a visible, transparent process, it is determined that a Supplier has market power in the immediate situation. A short term compromise solution may be that Suppliers can provide commitment cost and energy bids at the new 7:00 a.m. PPT bid submission timeline, subject to review as compared to the gas daily index, similar to eastern RTOs. This could also take care of the ISO concern indicated in the whitepaper that the ISO would not have enough time to re-run the DA market if the DA gas price index spiked. This could also have the added benefit of not requiring the CAISO to calculate opportunity costs, which would be added to CAISO calculated commitment costs, etc. resulting in a cumbersome, maintenance intensive, and ultimately inefficient and inaccurate process to pay a Supplier a CAISO calculated commitment cost value, which may ultimately be incorrect.

Alternate 2: Alternate 2 is essentially the status quo. The Timely cycle would be moved from 9:30 a.m. to 11:00 a.m. PPT, however this would be in the middle of the CAISO DA market timeline (10 a.m. to 1 p.m.), so Suppliers would be exposed to the same risk as today. Suppliers must anticipate a CAISO dispatch schedule, buy gas at 5:30 a.m. PPT, schedule that gas 1-1/2 hour later (11 a.m. instead of 9:30 a.m.), then at 1 p.m. procure or sell gas intraday to balance gas to its CAISO DA schedule. There is no change and no improvement or change in the alignment of the gas and energy markets.

Alternate 3: Alternate 3 moves the CAISO market timeline to slightly later in the day, noon to 3 p.m. It is likely that Suppliers would still procure gas at 5:30 a.m. PPT and then submit in the Timely cycle, and the result would be very close to Alternate 2. While it is possible that VERs may be able to improve their forecast, the actual difference in forecast accuracy from moving from 10 a.m. to noon will probably not result in much of a change in the forecast accuracy for a DA VER energy schedule. It is reasonable that much of the VER energy will remain scheduled closer to real time.

4. Is CAISO differently situated than other organized markets? How so?

Yes, there are several aspects in which the CAISO market is different.

Time zone - Regarding its time zone, the markets trade 2 hours clock time earlier than central time, thus power schedules that are aligned with national gas timelines typically take place early in the day, starting at 5:30 a.m. By moving the Timely cycle out 1-1/2 hours, if the CAISO day-ahead market timeline is moved (7-10 a.m.) to be completed before the Timely nomination cycle deadline (11 a.m.), then the gas market would need to adjust to a slightly longer open period (until 11 a.m.), and ICE would need to respond to its publication of the daily gas index price, likely to occur ½ hour after the Timely cycle (11:30 a.m. PPT) if it follows its current practice of today.

More VERS - In addition to time zone considerations, the CAISO supply mix is different from other regions and the growth of variable renewable resources will place increasing emphasis on the need for efficient coordination of gas and electric scheduling practices. Uncertainty in both the magnitude and hourly timing of gas burns will make purchasing and nominations of natural gas more complex, and if left uncoordinated, will place gas-fired generators at significantly more risk.

Separate non-CAISO administered capacity market - The CAISO measures market efficiency as a function of whether the energy market is approaching variable cost. However, RA is not a CAISO product, and is vastly insufficient to cover fixed costs. With disassociated markets in which a Supplier must attempt to obtain sufficient revenues to cover its costs, aligned gas and electric dispatch could potentially reduce some of the risk premium that is currently required to manage daily estimation of generation unit dispatch and the associated necessary gas procurement. DA market timeline alignment with the gas scheduling process should reduce risk and result in lower costs to consumers, while allowing a transition to an "as-bid" construct.

CAISO real time call option - Finally, the CAISO can essentially dispatch energy from suppliers in the real time at its option. The CAISO market needs to allow market participants to recover their costs.

Conclusions:

Shell Energy supports Alternative 1. Alternative 1 is not a final solution, but is a step in the right direction. Open issues remain, including assumptions that: 1) all necessary gas is actually available at day-ahead index (post 10 a.m. gas isn't traded at a different price); 2) the day-ahead gas index is the "right" price (which includes OFO, balancing, LDC and all other costs); 3) the chicken/egg problem of who wears the fuel price risk (unless the CAISO sees this as a first step towards allowing "as-bid" commitment and economic energy costs; 4) ratable/non-ratable flows and costs for such (which could be covered in an "as-bid" construct); 5) that enough of all the gas trades, especially in volatile markets, are either transacted on ICE or reported to Platts to become reflected in the index; 6) that this is a market and not a Power Pool (the New England power pool transacted at variable cost as all power plant fixed costs were already paid by ratepayers, however, the California capacity market is much different than ratepayer cost recovery for fixed costs); and 7) that increased penetration of intermittent generation and thus greater non-ratable burns will not impact western gas markets.

Self-Scheduling – The CAISO has expressed its objective to have as many Suppliers as possible provide bids in its DA energy market, and to reduce self-scheduling. Reducing self-scheduling becomes difficult under the present DA CAISO scheduling process and current bidding rules, as Suppliers have procured large quantities of gas which are typically difficult to liquidate if the Supplier does not receive a DA schedule. However, gas can almost always be moved at a price. The CAISO could create a mechanism to price fuel risk into bids/offers and encourage more bilateral hedging, or it could move to an "as-bid" cost recovery structure for Suppliers, with appropriate market power mechanisms. Under the Alternative 1 option, Suppliers would likely be able to offer more of their energy in the CAISO DA market, given the ability to still sell back excess gas at a DA gas index price prior to the Timely cycle.

While Shell Energy can live with either Alternative 1 or 2, it would appear that FERC has a specific intent in both the M-2 order and Order 809 to align gas and electric markets. Alternative 1 would provide a solution that would reduce the quantity risk of gas procurement, and should result in lower costs to consumers. The ISO would still need some accommodation for price risk, and should evaluate and retain a structure to allow fuel cost recovery, and to ultimately allow Suppliers to bid their commitment costs as well as economy energy bids aligned with a DA gas price.