Via email and posting

October 14, 2022

**TO:** NAESB Gas-Electric Forum and Interested Parties

**cc:** NAESB Board of Directors, Executive Committee (EC) Members, EC Alternates, Members, and Advisory Council

**FROM:** Rae McQuade, NAESB President & Jonathan Booe, NAESB Executive Vice President & COO

**RE:** NAESB Gas-Electric Forum Survey Responses – October 10, 2022

Dear NAESB Members, GEH Forum Participants and Interested Parties,

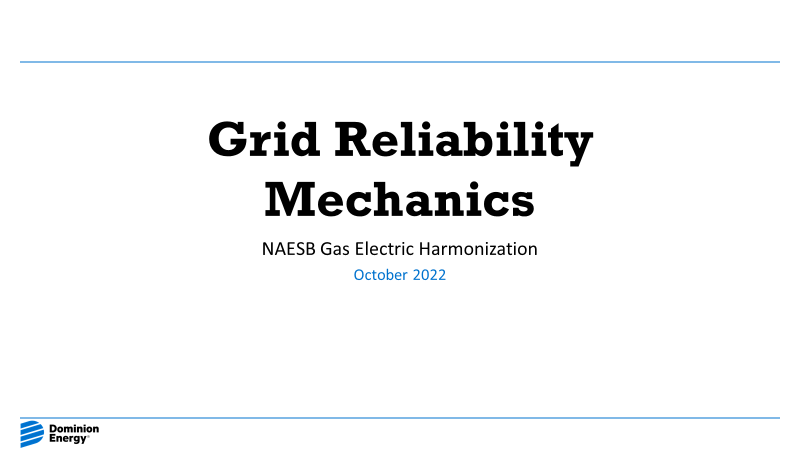
Please find below the comment received by the NAESB Office in response to the survey/request for comments that was distributed on October 3, 2022 soliciting general comments related to the agenda topics for the October 21, 2022 meeting: Items 3.a.i, 3.b, 3.c from Recommendation 7: <https://www.naesb.org/pdf4/geh092322w1.docx>.

| **Responses Submitted by October 10, 2022 – Question 1** | | | | |
| --- | --- | --- | --- | --- |
| **Question 1** | | Please provide general comments and recommendations for the forum attendees to consider that provide practical solutions for lack of natural gas pipeline capacity during periods of unanticipated demand when building additional infrastructure is not possible or timely. | | |
| **#** | **Organization** | **Representative** | **Market/Segment** | **Comment & Specific Recommendation** |
| 1 | Interstate Natural Gas Association of America (INGAA) | Christopher Smith | WGQ - Pipeline | INGAA cautions against the use of short-term solutions that apply only in certain circumstances, especially without a precise definition of the “periods of unanticipated demand” that trigger use of those solutions. The rules governing natural gas and electricity markets must be clear, consistent, and predictable. Uncertainty regarding what rules apply during what times is extremely disruptive and will further impair the operation of natural gas and electricity markets. Rule changes triggered by “periods of unanticipated demand”—a phrase open to widely divergent interpretations—will inject significant uncertainty into markets.  This is not an idle concern. Due to the increasing importance of natural gas in maintaining a reliable electricity system coupled with ongoing obstacles to the timely development of natural gas infrastructure, periods when demand for natural gas exceeds natural gas pipeline capacity occur regularly and can no longer be considered “unanticipated” in parts of the United States. For example, Gordon van Welie, President and CEO of ISO New England (“ISO-NE”), informed Secretary of Energy Jennifer Granholm that, “[d]uring the coldest days of the year, New England does not have sufficient pipeline infrastructure to meet the region’s demand for natural gas for both home heating and power generation."[[1]](#footnote-1) This is not a new problem. ISO-NE “has been active in expressing its concerns . . . with the availability of sufficient quantities of fuel.”[[2]](#footnote-2) Given the increasing demand for and constrained supply of natural gas, solutions intended to apply only in exceptional circumstances (i.e., periods of “unanticipated demand”) will be used more frequently and during some periods might supplant the standard market rules.  INGAA members already work to provide as much pipeline capacity as possible, subject to the operational limitations of the pipeline. The United States ultimately needs more natural gas infrastructure—pipelines and storage—to address the imbalance between demand for natural gas and natural gas pipeline capacity. INGAA reiterates that organized markets should develop mechanisms that properly value reliability and facilitate power generator investment in the gas services they require, including supporting new gas infrastructure investment when needed. It will take time to develop these mechanisms and so we must act now to enable pipelines to expand in a timely manner. We cannot afford to reform the pipeline permitting process until after we have explored other approaches that, at best, will have only a marginal effect on the imbalance between demand for natural gas and available pipeline capacity. |
| 2 | LS Power | Marji Philips | WEQ - Generator | Please see response in the last question. |
| 3 | Process Gas Consumers Group, Industrial Energy Consumers of America, and American Forest and Paper Association | Andrea Chambers | WGQ – End User | Process Gas Consumers (“PGC”), American Forest and Paper Association (“AF&PA”) and the Industrial Energy Consumers of America (“IECA”) file these joint comments. PGC, AF&PA and IECA represent industrial and manufacturing entities that are energy-intensive, trade-exposed companies, referred to jointly here as “AIP”. AIP does not agree with the premise of this question, to the extent that it assumes that building additional infrastructure is not possible or should not be pursued. AIP members plan ahead to obtain adequate natural gas supplies and natural gas pipeline capacity to run their plants in a safe and reliable manner at all times, including in times where demand may be extremely high. AIP members do not rely upon last minute scrambling for natural gas pipeline capacity nor natural gas supply. Instead, AIP members sign long-term firm pipeline transportation agreements (typically between 10-20 years), which allows the pipelines to build transportation capacity to serve their needs safely and reliably. AIP strongly urges the Forum to move away from the idea of reliance upon curtailment arrangements, as such arrangements cannot make up for the lack of capacity being built to serve electric generation demand. Instead, AIP asserts that, if natural gas-fired generation must be relied upon to serve peak demand, generators that are critical or essential to provide power to consumers and rely on natural gas as a fuel source should be required to obtain firm natural gas transportation capacity and supply, so that the pipeline transportation capacity that is needed to move their supply will be constructed and gas will be produced in order to serve their demand.  AIP also suggests that the electric reliability issues appear to be created by the fact that the wholesale electricity markets do not allow generators to be compensated for their costs of firm gas supply and firm gas transportation needed to serve them in peak periods. AIP urges FERC to require any gas-fired electric generators that are critical for serving load on peak be required to hold firm pipeline capacity and natural gas supplies, and that such generators be paid for the costs of firm natural gas pipeline capacity and firm gas supply through the electricity markets as part of the cost of reliable electric service. Capacity prices for electricity would then create the proper incentives for generators to pay for pipeline capacity or storage for these must-run units.  As to unanticipated demand, it seems that the electric forecasts are not accurate, which is causing the spike in demand to be “unanticipated.” During the hearings concerning the Uri storm, witnesses testified that they disagreed with the forecasted demand from ERCOT and expected demand to be higher than what was forecasted. AIP suggests that the ISOs and RTOs should revise their forecasting by building in a cushion in their forecasts when a big storm is approaching so that the higher demand is not “unanticipated.”  AIP notes that building adequate transportation capacity in advance of emergency situations may increase the cost of wholesale electricity, but so does the lack of having sufficient firm natural gas supplies contracted for, or firm natural gas transportation built and contracted for, in advance of periods of high demand, such as extreme weather events. This increase in cost is due to generators being forced to go into the market to try to purchase natural gas or obtain release capacity at the time of peak demand when there are shortages of capacity and transportation, with no guarantee that it will be available at any price. If the decision is made for policy reasons not to construct additional natural gas transportation capacity, then natural-gas-fired generation should not be relied upon for peak demand or unanticipated demand, rather, alternatives such as dual-fuel capable units, or storage should be planned for such events.  AIP members pay for firm pipeline transportation and gas supplies and do not rely upon time of use procurement due to the lack of reliability and increased cost exposure to the spot market at these times. AIP suggest that the electric industry should not expect reliable gas-fired electric generation at reasonable prices without taking similar actions to plan for future supply and delivery of such supplies. |
| 4. | Natural Gas Supply Association | Pat Jagtiani | WGQ – Producer | Much of the discussion thus far at the forum has focused on how natural gas markets can more readily meet last-minute needs of natural gas generators that are relying on just-in-time procurement practices for attaining both natural gas capacity and supply. Most importantly, it must be clear that just-in-time procurement practices are not sustainable practices to support grid reliability. Also, encouraging such practices only exacerbates the problem of how to finance pipeline or storage capacity expansions, which can only be financially viable when supported by customer commitments. Before we expend considerable resources on “fixing” issues with generator procurement issues, it is imperative that we first hear directly from gas generation owners about what obstacles stand in the way of reliable fuel procurement.  Most importantly, all gas customers should build a diverse portfolio of contractual arrangements and assets that align with their unique needs and circumstances. Generators in organized markets may be called upon “unexpectedly” by regional operators but they are aware that this may occur and, if they are obligated through their capacity payment obligations to run, advance arrangements must be made that fully align with this obligation. There are natural gas market products and service options available today to generators, and all gas customers, that will help customers fulfill their just-in-time needs. These products include pipeline no-notice and storage service options, call options with gas marketers and other fuel management or flexible service agreements. There are other ways in which power generation customers can ensure that they can meet their just-in-time requirements, such as having dual fuel or on-site LNG.  Each gas generator’s needs are unique and therefore, not all generators may need firm products to be reliable when called upon unexpectedly. However, if no prearrangements for natural gas market products or other assets are in place, generators are assuming the operational and price risks associated with going into the intra-day market at times in which gas markets are relatively illiquid to procure pipeline capacity and/or gas supply. During those times, pipeline capacity or gas, if available, require payment of a premium price because the capacity or gas is essentially being bid away from other customers to whom it has previously been sold and/or stored by a party who managing their own supply needs in advance.  Natural gas markets work very reliably for those natural gas customers who contract for the services they require and utilize the tools available to manage their exposure to daily market conditions. LDCs, industrials and generators in vertically integrated markets do not appear to face similar issues so it behooves us during this forum to explore why organized power market structures are having difficulties emulating reliable procurement practices seen in other markets that are so fundamental to maintain reliability. This is a fundamental question that organized markets are facing as they look for new market-based approaches that successfully incentivize behaviors that reduce grid reliability risks.  While we understand that the market structure in organized power markets makes it difficult to recover the costs of advance arrangements, it is the generator’s responsibility to do so, when they have committed their capacity to the market. Thus, power market design changes must be made that can provide adequate incentives for gas-fired generators to procure gas market products that align with their needs. For example, regional operators could develop special market products that recognize the value of calling on units expectedly to provide ramping and frequency required to maintain reliability.  Over the past two decades and even today, in many instances, it has perhaps serendipitously worked out for many power generation customers to not contract for gas arrangements that allow for fulfilling last-minute needs. Pipeline companies often accommodate non-ratable hourly flows if they can do so without impacting their own operations and services to other customers. However, as generators are asked to provide faster, more frequent, and steeper ramping to balance ever-increasing the intermittency of variable energy resources such as wind and solar – or as pipeline capacity utilization rates are higher and their systems are more constrained – the ability to accommodate requests for variable flow could dramatically decrease and power generation customers will not be able to rely on such flexibility. Constructing a diverse portfolio of gas assets is the best way to provide the level of reliability and “insurance” needed for security of fuel. It does not matter if that need is for 365 days, 14 days or three hours, if it is needed to maintain reliable operations, those needs must be addressed through some type of reliable contractual commitment.  Perhaps in this forum we can all find ways to tweak the natural gas systems or pipeline nominations to try to squeeze out more than is available today but, these changes will be only marginal improvements that cannot make more capacity magically appear. Nor will these changes incentivize contracting practices that provide the financial commitments necessary to finance gas infrastructure that may be needed to accommodate ramping capabilities for balancing the ever-increasing levels of variable energy resources.  It is imperative in this forum discussion that we seek input from gas generators to better understand if they are too have concerns about gas procurement before expending considerable resources attempting to “fix” issues that they may not be experiencing. Some contend that capacity payments should be sufficient to allow gas generators to secure the fuel arrangements and we appreciate that is how it was intended to work. However, the mere fact that one of the key question in this forum pertains to whether generators have the ability to procure natural gas just-in-time underscores that, in organized markets, capacity payments are likely not sufficiently producing the price signals needed to incent generators arrange reliable services that can accommodate their last-minute needs.  Due to the extent of disruptions during Winter Storm Uri, not all firm contractual commitments for gas supply could be honored, which could lead some to argue that Winter Storm Uri demonstrated that contractual arrangements do not matter, especially during extreme events. However, the FERC-NERC Final Report correctly finds that the opposite is true – in fact, contracts matter the most during extreme events. The Final Report found that, “Although generating units with firm natural gas commodity and transportation contracts were not immune from outages and derates due to natural gas fuel supply issues, of the 357 natural gas-fired generating units across the three footprints that had an outage or derate due to natural gas fuel supply issues, only 29 percent had both firm natural gas commodity and firm natural gas pipeline transportation contracts for any volume…. Even though the figure indicates that natural gas shipped to natural gas-fired generating units with firm interstate pipeline capacity was less than contracted volumes…, the majority of nominated natural gas was delivered to natural gas-fired generating units. Natural gas-fired generating units with interruptible transportation contracts were still able to nominate and ship some gas under those contracts, but at smaller volumes than gas shipped under firm transportation contracts.” Also, contracts determine how liability and penalties are allocated in the aftermath of an event such as Winter Storm Uri.  In terms of specific recommendations, NGSA suggests:  • Hear directly in this forum from those representing gas-fired generators about what obstacles they face with respect to gas procurement.  • Consider the creation of new market-based services in organized markets that value key attributes such as ramping and frequency.  • Explore power market changes to capacity performance/pay-for-performance type programs that provide market signals that encourage more reliable fuel contracting practices.  • Consider multi-day clearing that gives generators more advance notice ahead of extreme weather events.  • Review current accreditation methods in organized markets to ensure they are aligned with reliable fuel procurement practices.  • Similarly, regional operators could consider whether they have sufficient reserve margins that accurate account for reliable fuel practices and could increase margins as needed through other resources.  • Hold educational sessions on natural gas market products available today to manage last-minute generator needs.  • Explore whether power customers can pool resources or through the regional operator to invest in reliable natural gas arrangements and/or assets that build a more reliable regional portfolio.  • Review how generators in non-organized markets meet their reliability obligations and whether they experience the same level of concerns associated with just-in-time procurement.  • Consider whether, during critical periods, pipelines should preemptively waive imbalance penalties (OFO, unauthorized overrun, daily/hourly imbalance) for those shippers that are putting gas on the system. |
| 5 | Bureau of Economic Geology, University of Texas at Austin | Gurcan Gulen and Ning Lin | Other Market Participant/Observer | The comments submitted prior to and the discussion during the 9/23 meeting suggest that narrowly focusing on securing natural gas to power plants during extreme weather events, let alone only extreme cold weather events, will miss an opportunity to address fundamental gas-power harmonization challenges organized electricity markets have been facing for well over a decade.  Also, we must acknowledge that there are other solutions to problems caused by extreme winter weather. Investigations, including those by the Bureau of Economic Geology and other UT-Austin researchers, strongly indicate that winterization will almost certainly avoid gas supply shortages of the kind seen during Uri in a repeat of Uri-like conditions. Winterization includes, among others, relatively straightforward and inexpensive retrofit of critical equipment along the natural gas supply chain for extreme cold, having backup generation/fuel for compressor stations and storage facilities, and excluding critical gas infrastructure that still runs solely on electricity from interruptible load list of ERCOT and/or utilities. Most power plants have already implemented winterization as directed by the PUCT and ERCOT.  All relevant agencies have been involved in developing solutions, including joint efforts under the Texas Energy Reliability Council. The cost of such winterization efforts can be covered from the regulated rate base. Because, first, markets cannot handle extreme cold weather events with low probability of occurrence. Moreover, historical data may not be informative as frequency and intensity of such weather events may be increasing. When extreme weather occurs and infrastructure is disrupted, prices would have to reach very high levels, as seen during Uri, to induce long-term investments. But such high prices are undesirable by the society and do not address the issue fast enough, which brings us to the second point. The electricity market price signal must flow up the natural gas value chain to induce midstream and even upstream actions. Even if electricity market price signals could be enhanced, it will take time for gas market participants to make necessary investments. In response to Uri, ERCOT is developing a new service: [firm fuel supply service (FFSS)](https://www.ercot.com/services/programs/firmfuelsupply). The gas industry must be fully engaged in this process. But it is too early to tell what the final structure of FFSS will be and whether it will induce the necessary actions by gas-fired plants, the gas midstream industry and gas suppliers.  As a result, it is reasonable to act fast and pass through the cost of winterization to energy consumers. Obviously, a better understanding of weather event probabilities and impacts across the natural gas and electric power infrastructure is necessary to avoid overspending on winterization while preventing extreme outages to gas and electric customers. But, it is reasonable to expect that, partially based on the Uri experience, winterization actions can be prioritized and implemented much more quickly than any tweaking of market rules would encourage. Such prioritized deployment would help manage costs as well.  Given this alternative set of solutions, it might be better for the GEH effort to address the fundamental challenge of organized electricity markets that will remain dependent on dispatchable generation. That challenge is the mismatch between market price signals and the need for sufficient revenues to keep dispatchable plants online and/or induce new ones to be built, and with reliable fuel supply.  The challenge appears more difficult in the energy-only market of ERCOT, but it also exists elsewhere as evidenced by decade-long efforts to address resource adequacy (for a review of efforts at different markets through 2019, see our report [Net Social Cost of Electricity](https://store.beg.utexas.edu/special-books/3777-us0007.html)). Recently, an increasing number of stakeholders have raised similar concerns about the inadequacy of electricity market structures and, hence, price signals. Here are two very recent examples:  [Broken markets: Slick Rick, Doug E. Fresh, and the global strain on the single clearing price | Utility Dive](https://www.utilitydive.com/news/broken-markets-slick-rick-doug-e-fresh-and-the-global-strain-on-the-sin/633324/?utm_source=Sailthru&utm_medium=email&utm_campaign=Issue:%202022-10-05%20Utility%20Dive%20Newsletter%20%5Bissue:45015%5D&utm_term=Utility%20Dive)  <https://elcon.org/can-we-afford-a-single-clearing-price-electricity-market/>  Although gas-fired units are increasingly seen as necessary backup for intermittent and variable generation from wind and solar, all the tweaking in organized electricity markets have not yet engendered cash flow security among the operators of dispatchable plants. One reason is the increased and rapid addition of subsidized, low-dispatch-cost wind and solar (and, increasingly, batteries), which raise concerns about loss of further market share and low prices when dispatched. Importantly, most electricity market reforms on enhancing revenues do not even consider the additional costs of securing natural gas supply to power plants. And, in regions where policies ban and/or local opposition block new gas infrastructure, the gas market is changing in uncertain ways, which may put gas-fired power plants’ ability to dispatch when called upon by the system operator at risk. No amount of electricity market tweaking will solve the problem of insufficient natural gas midstream infrastructure.  One idea that was discussed in some electricity markets (for example, in the UK) is for intermittent and variable resources to be required to provide proof of firm, dispatchable supply. The developers of such resources can do so by contracting with dispatchable generators and/or building storage. The revenues from such contracts may still be insufficient for dispatchable gas-fired units to secure gas supplies during extreme weather events but it will fix a fundamental cost allocation problem in power systems.  Another idea is the return to some form of IRP, perhaps with more competitive features for the procurement of resources, which is defined further in our report [Net Social Cost of Electricity](https://store.beg.utexas.edu/special-books/3777-us0007.html). The energy transition put us on a path that is different (across multiple dimensions) than the electricity systems of 30 years ago when competitive electricity markets promised improved efficiency. Today, that single objective is superseded by multiple objectives. The society seems to prioritize addressing climate change and grid reliability higher than market efficiency. Building a large amount of long-distance, high-voltage transmission capacity is regaining prominence, which is reasonable since a more integrated grid is necessary for least-cost addition of wind and solar while maintaining high reliability standards. The demand side must play a more integral and responsive role, which seems to be getting easier with deployment of modern technology, including distributed resources. Some planning seems necessary to balance generation technologies, storage, T&D, demand-side and fuel supply to achieve the least-cost transition while keeping the power system reliable in day-to-day operations and resilient to extreme weather events. |
| 6 | MISO, PJM & SPP | Joshua Phillips | WEQ – IGO & Planner | For some areas within the south central US region, gas transportation (pipeline) capacity did not appear to be the limiting challenge in the most recent event, impacts were predominantly caused by the loss of gas supply/production during Winter Storm Uri. This created significant challenges for acquiring the needed fuel for generation of electricity. Capacity enhancing approaches such as storage outside of the freezing areas would have likely had a greater impact during the recent event than additional transportation capability. Increased winterization of production facilities should be considered to ensure that a supply loss does not occur. Lastly, identification of the critical facilities and improved communication with the electric industry so electric system operators can identify which circuits need to be excluded from load shed would also reduce the impact to the gas supply that caused significant challenges during the recent event.  A number of the Commenters to date focus their responses on underscoring, in their view, the value and need for electric generation to contract for firm natural gas transportation. This is clearly an important discussion although as a threshold matter, the forum should consider whether it remains prudent to limit electric generators (and other customers) largely with a binary choice on certain key pipelines of contracting for firm service 24 hours a day/365 days per year or contracting for interruptible transportation (IT) service. Rather, this forum should assist in ‘jump-starting’ the offering of firm services that are more tailored to the actual needs of electric generators and the reliability of the electric grid at certain peak times. Of course, any such tailored services need to provide adequate compensation for the recovery of the pipeline’s fixed costs. However, the traditional year-round firm service offering may not be the most efficient way to offer and price pipeline services to electric generators and may be leading to inefficient and sub-standard non-firm contracting by generators as a result. The forum should further explore this critically important issue and encourage the development of more tailored services for the electric generation sector.  In addition, many of the comments submitted to date pre-suppose that firm transportation costs are not recoverable in the wholesale markets, an argument that simply is not universally correct. For example, Section 6.8 of Attachment DD of the PJM OATT specifically authorizes generators to recover “firm gas pipeline transportation; (b)natural gas storage costs; (c) costs of gas balancing arrangements and (d) costs of gas park and loan service”.  We also read the above question as appropriately going beyond simply the prioritization of firm service over interruptible service. Many commenters focus on the value of firm service which the RTOs overall do not dispute. However, this NAESB forum should also address the need for regulatory rules to address prioritization of service among firm service customers (other than today’s pro rata prioritization) in situations where electric generators have firm service but may face curtailment in order for service to be available to other uses that may not carry the same human health and welfare impact that would occur were electric service lost to ultimate customers due to a disruption on a given pipeline. In other words, should the pipeline face a constraint due to operational reasons or a physical or cyber incident which requires reductions in service to firm service customers, should a ‘human needs’ prioritization be triggered that would recognize the human needs value of maintaining short term reliability of electric service along with other human needs requirements.  Other practical solutions for lack of natural gas pipeline capacity during periods of extreme cold weather include:  1. Increase line-pack in the pipeline. Typically, weather forecasts indicate when extreme cold weather is expected one to two days ahead of time. Under these conditions, line pack could be increased from its typical levels of 80-85% to 90-95%, similar to what is done in the electricity industry with emergency facility ratings. This should not and cannot be an everyday occurrence because increased line pack at these levels stresses the underlying equipment; however, under limited emergency conditions, this would provide additional supply to end users and natural gas-fired generation.  2. Enhance bilateral markets to release unused firm transportation. During Winter Storm Uri, some Commercial and Industrial (C&I) end users of natural gas had workers who were unable to get to work and therefore no longer had a need for the firm capacity they had purchased. Enhanced market mechanisms that provide a means to efficiently and effectively release this capacity for resale would allow the capacity to be resold and better utilized during extreme events. Such a mechanism could allow “non-critical” firm capacity holders to opt into a voluntary pre-arranged agreement to transfer their capacity to a nearby generator on a short term basis to facilitate their operation during critical periods, such as the long holiday weekend of Winter Storm Uri. Clear compensation and cost recovery rules would of course need to be established as part of this operation.  3. Prioritization Among Firm Service Customers---Clearly defining human needs prioritization of service to electric generation deemed by the system operator when facing a reliability emergency as critical to maintaining reliability. Under this premise, the electric system operator would declare an emergency need for one or more gas fired generators to maintain grid operations. These units would be given the gas service priority level equivalent to a human needs customer. To effectuate this, a state and/or federal regulatory entity may need to mandate that existing firm service to “non-critical” customers be shifted to these critical electric generating facilities. Similar to above, clear compensation and cost recovery rules would need to be established to effectuate this process. |

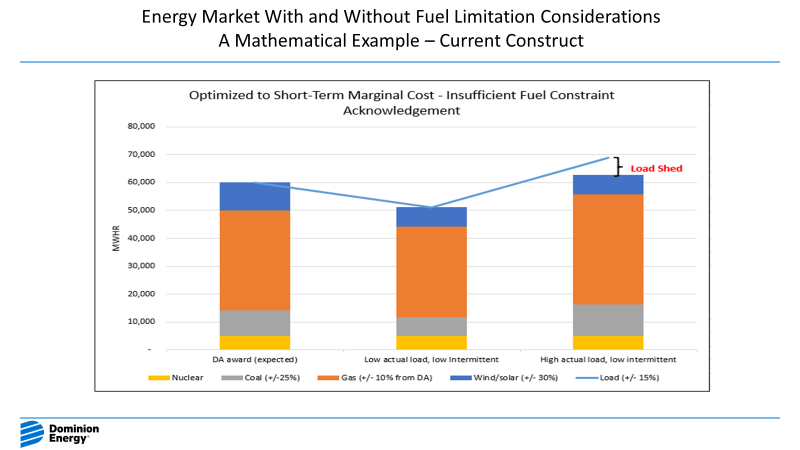
| **Responses Submitted by October 10, 2022 – Question 2** | | | | |
| --- | --- | --- | --- | --- |
| **Question 2** | | Please provide general comments and recommendations for the forum attendees to consider that provide practical solutions for syncing deadlines between gas and electric markets when there is unanticipated demand for gas-fired power generation that may not support existing deadlines, without penalizing the existing market participants. | | |
| **#** | **Organization** | **Representative** | **Market/Segment** | **Comment & Specific Recommendation** |
| 1 | Interstate Natural Gas Association of America (INGAA) | Christopher Smith | WGQ – Pipeline | INGAA reiterates its concerns with the adoption of different market rules that are not consistent over time but rather change based on ambiguous circumstances such as “unanticipated” demand. These concerns are acute when fluctuations in demand could change deadlines in the natural gas market from one day to the next. Natural gas market participants need consistent, predictable deadlines; any changes to gas market deadlines must be applied uniformly throughout the year and cannot vary based on circumstances like demand. Moreover, the deadlines must be consistent throughout the entire natural gas pipeline system because shippers may transport gas over several pipelines to their delivery point. Deadlines cannot vary across pipeline segments based on the demands of the region in which the segment is located.  The current natural gas scheduling rules are spelled out clearly by FERC and each pipeline’s tariff. Shippers currently may submit nominations—a request to move a specific quantity of gas from one point to another point on an interstate pipeline using a single contract—seven days a week during one of five “cycles.” Two cycles—Timely and Evening—occur during the day before the gas would flow along a specified path from receipt point(s) to delivery points(s). Three cycles—Intraday 1, Intraday 2, and Intraday 3—occur on the same day the gas would flow. Each pipeline’s tariff will dictate the priority of service for each nomination, and the pipeline will review the tariff and the shipper’s contractual rights when “scheduling” nominations (i.e., determining the quantities that will be able to flow through the pipeline system and/or points of interconnect). Once scheduled:  • Shippers with firm transportation rights can “bump” or take priority over shippers with interruptible transportation rights in any nomination cycle except Intraday 3. (This is the NAESB “No Bump” rule that FERC approved.)  • Shippers with firm transportation rights cannot bump shippers with lower priority firm transportation rights (as determined by the pipeline’s tariff). (This is FERC policy.)  • Shippers with interruptible transportation rights cannot bump shippers with lower priority interruptible transportation rights (as determined by the pipeline’s tariff). (This is FERC policy.)  Some participants in this proceeding stated that changes to the schedule of events in electric markets would allow natural gas-fired generators to purchase natural gas at times when supplies are more abundant.[[3]](#footnote-3) If the ISO/RTO issues day-ahead awards in advance of the pipelines’ Timely Cycle, then this change might help generators that either (1) hold firm transportation rights and are able to obtain natural gas or (2) purchase a bundled package of natural gas and transportation from a marketer.  Because aspects of organized wholesale electricity markets deter merchant natural gas-fired generators from holding firm transportation rights, generators will generally remain lower priority and at risk of being unable to transport natural gas regardless of the timing of day-ahead awards. In regions with insufficient pipeline capacity during periods of high demand, firm shippers like LDCs will nominate early (i.e., in the Timely Cycle) for the full amount of their contracted capacity. Earlier day-ahead awards to natural gas-fired generators might enable generators to nominate Timely, but earlier awards will not create capacity on the pipeline, nor allow generators with interruptible transportation to bump shippers with firm transportation, nor enable non-ratable take, which generators might need to respond to sharp, sudden increases for demand in electricity.  INGAA supports efforts to explore changes to the electricity markets that might promote reliability, but, as a NERC official stated, greater coordination between the gas and electric sectors will not be sufficient to maintain reliability because “[e]very ounce of efficiency has been squeezed out of [gas-electric coordination]. And coordination really doesn’t let more gas flow.”[[4]](#footnote-4) The priority must be efforts to enable generators to recover the cost of firm transportation service (if firm service is available) and to reform the permitting process to remove obstacles to the expansion of natural gas infrastructure. |
| 2 | LS Power | Marji Phillips | WEQ – Generator | Need to respect regional differences in terms of how standards/requirements are implemented |
| 3 | Process Gas Consumers Group, Industrial Energy Consumers of America, and American Forest and Paper Association | Andrea Chambers | WGQ – End User | AIP supports the comments of NGSA which state that the ISOs and RTOs should move the time for dispatching generation to earlier in the day. Moving to an earlier time will allow generators who need to purchase gas the ability to access the market at the time when the gas market has more liquidity, instead of dispatching electric generation after most gas has already been sold for the day or the weekend. This change would also allow the market to function and not penalize other market participants who purchase their gas at times when the supply is more readily available. AIP understands that NYISO does perform electric dispatch before the start of the natural gas day and this allows its generators to secure natural gas when the market is liquid.  AIP notes that the gas markets generally work very well to allocate the capacity needed during the day through the intra-day renomination process. However, while changes to scheduling might provide some additional flexibility, scheduling changes will not make up for the lack of capacity being built to serve overall demand. |
| 4 | Natural Gas Supply Association | Pat Jagtiani | WGQ – Producer | As we suggested above in our response to Question 1, it is possible that earlier dispatch clearing times in organized markets would assist generators in knowing what they need to procure in advance of the time when most natural gas is sold (during the morning before the timely nomination cycle). Purchasing natural gas during the liquid times of the day when gas is more readily available also allows generators the time needed to nominate during the pipeline’s Timely Cycle, which confirms that a firm shipper will receive the gas supply they need.  While there are many market products available that help gas customers reliably meet “unexpected” needs, focusing on natural gas industry tweaks appears to be a way to further obviate the need for advance contracting, which exacerbates the impediments to building more pipeline expansions. Obviously, the more available pipeline capacity, the greater the ability to provide gas to customers with “unexpected” needs that are relying on just-in-time procurement practices. However, pipeline companies, not unlike any other provider of a product or service in any other industry, do not expend their business without knowing that it will be a sound financial investment -- to do so would not be in the fiduciary interest of their stakeholders. Moreover, pipelines generally will not be able to secure financing for capacity that is not fully subscribed by firm shippers. Given the uncertainty and expense related to the pursuit of NGA Section 7 permits, in addition to the cost of construction, it would be untenable for a company to move forward without customer commitments.  The last round of discussions on gas-electric harmonization at NAESB resulted in one additional nomination cycle. Yet, the additional cycle has not led to any meaningful uptick in transactions supporting the power markets or marked improvements that change the availability of gas given that most later cycles are used only to make paper changes and minor adjustments to daily scheduled loads. Given our experience with the addition of this cycle, we also do not expect that adding even more nomination cycles, even hourly, would provide anything more than marginal improvements. However, to the extent that our power generation customers would like to explore the idea of voluntary additional nominations cycles, we are open to exploring that further to see if there is mutual value in that proposition.  Almost all natural gas supply is sold in the morning when the market is liquid and maximum pipeline capacity is available. Therefore, more nomination cycles throughout the day will not change these facts. For an intra-day market to develop, there would need to be appropriate price signals and robust market participation. That means incenting suppliers to “reserve” supply that must flow, which is very operationally risky for producers and the price would reflect that risk. Similarly, attempts to somehow “create” weekend trading would not materially change trading behavior; with most transactions still executed on Friday through the weekend absent price signals that drive change. Again, we stress that, unlike the constructs in place when power markets were created, natural gas sales are in a competitive market in which we do not have rules in place for when natural gas sells. Rather, the market and timing of transactions is left up to the buyers and sellers and evolves over time.  To maintain flow assurance from producing wells, natural gas producers deliberately attempt to sell their product far in advance of the day of flow. Most gas production is sold on a monthly basis and the bulk of the remaining gas is sold on a daily basis on a business day ahead basis, typically during the Timely Cycle to allow sufficient time for scheduling. To prevent great operational risk, producers generally do not hold product off the market and reserve for unexpected needs. However, some producers and marketers that have a diverse array of assets and contractual arrangements can often find a means to provide varying amounts of supply when called upon after most gas is sold. But these actions typically require relying on supply from other sources, such as storage, which will typically result in payment of a premium price by a customer that continues to rely upon just-in-time procurement practices.  As mentioned above, producers do not generally hold production volumes in reserve for opportunities that may never materialize and are hugely incentivized to market their production during the Timely Cycle when the market is most liquid and pipeline capacity is available. Producers can be somewhat more flexible with volumes they may hold in storage. Below, we have outlined some general points about the importance of ensuring natural gas continues to flow:  • At its core, gas marketing for producers/marketers original purpose was to maintain flow assurance for both associated and non-associated natural gas supplies (especially associated gas) from producer’s upstream producing wells/facilities. Although the market has become a bit more complex in recent years, flow assurance remains one of our top priorities.  • Pipeline capacity is often fully awarded during the Timely Cycle and therefore, unavailable in these later nomination cycles, particularly in periods of peak demand, which could impact a producer’s ability to flow its production.  • If associated gas (aka casinghead gas) is not sold, producers may be required to curtail or shut-in oil wells (or face potentially onerous pipeline imbalance/OFO/unauthorized gas penalties). In the past, associated gas often used to be flared or vented if it could not be sold, but now producers do all they can to prevent flaring/venting.  • When oil wells are curtailed or shut-in, they can load up with water or experience other issues that can necessitate costly procedures to bring the well back online or back to full production.  • Interruption of stable producing rates can also damage physical flow characteristics, both through the oil and gas formation and impact producing wellbores. These issues can sometimes be corrected with costly procedures, but the damage may not be fully repairable and can lead to both reduced deliverability from wells and reduced recovery of ultimate reserves. Similar issues/concerns exist with non-associated gas. |
| 5 | MISO, PJM & SPP | Joshua Phillips | WEQ – IGO & Planner | Prior to responding to the question, we would like to clarify that weather forecasts typically indicate when extreme cold weather is expected; i.e. one to two days ahead of time. Therefore, while it may not be possible to accurately anticipate demand even one week ahead of time, as the operating day approaches, there is increasing certainty in the weather forecast, so that one can anticipate demand with higher confidence. Our following comments speak to what practical solutions may be considered.  In Nov. 2021 the ISO RTO Council’s (IRC) Standards Review Committee (SRC) and Electric Gas Coordination Task Force (EGCTF) provided comments on opportunities to improve availability of gas and information about the gas.  The impact from winter storm Uri was exacerbated by a holiday weekend, where nominations would occur on Friday to cover gas demand for a 5-day forecast. As heard during the call on September 23, 2022, gas generation is subject to risk when nominating on a day ahead basis balancing gas nominations and bidding power into electric markets. Longer lead forecasts tend to be less efficient, reducing accuracy, for anticipated gas demand and adding incremental risks to generators who may be nominating gas service. Although some gas is available to be traded during non-market hours on the weekend, this is not an efficient alternative for an electric system that is a 24x7 market. Gas fuel electric generators in organized electric markets offer at their lowest possible price to be called to run. Purchasing gas contracts 48 hours in advance has a detrimental price exposure for these generators and could cause unnecessarily high electricity prices for the entire market. Consideration should be given to enhancing the gas market’s availability during weekends and holidays to provide additional abilities to efficiently procure the needed gas for market participants.  Modifications to the gas scheduling requirements would enable additional flexibility for gas producers and gas-fired generators. With increasing need for natural gas fired generators to respond to greater fluctuations in energy production from the proliferation of variable and intermittent electric resources, shorter lead times for scheduling periods will give both buyers and sellers of natural gas increased flexibility to meet the reliability needs of both industries. This additional scheduling flexibility will also enhance opportunities for gas producers during times when temperature forecasts deviate from expectation. Given industries’ changing needs, exploration of hourly gas nominations should be considered.  During Winter Storm Uri, some industrial gas users shut down their operation which resulted in additional firm capacity not being utilized during such events. With no organized clearinghouse to facilitate the secondary market, this left those with the firm capacity to identify purchasers for a bilateral transaction. Some of this capacity went unsold and unused. This situation exemplifies the efficiencies that could be gained through an organized clearing house to match sellers and buyers, which would increase market liquidity and efficiency. A standard approach to posting, transacting, and facilitating these transfers is an opportunity for NAESB to work with existing trading platforms to enhance this secondary market. |

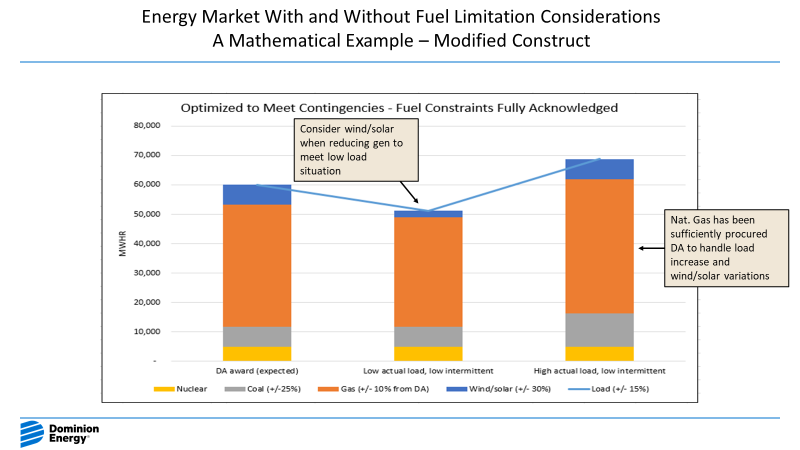
| **Responses Submitted by October 10, 2022 – Question 3** | | | | |
| --- | --- | --- | --- | --- |
| **Question 3** | | Please provide general comments and recommendations for the forum attendees to consider that provide practical solutions for addressing any information limitations that could provide the data needed to ameliorate some of the problems seen in Storm Uri | | |
| **#** | **Organization** | **Representative** | **Market/Segment** | **Comment & Specific Recommendation** |
| 1 | LS Power | Marji Phillips | WEQ – Generator | We are concerned that we are jumping to solutions when we lack a complete understanding of the scope and specifics of the lack of natural gas pipeline capacity. For example:  o The challenge varies from region to region. New England and New York are infrastructure constrained due to policy goals. PJM is not. MISO and SPP infrastructure may not be weatherized against extreme events, and this is true for ERCOT as well, with more profound impacts because issues may start at the well head. We need to ensure we understand the fundamental drivers of unreliability in a granular, location-informed way and that we do not impose overly broad solutions.  o Do we understand all the impacts of extremely cold conditions? Problems may start at well heads and perpetuate throughout the gathering and delivery process: from equipment related to the production of the commodity to its transportation.  o We may not have a good understanding of LDC procurement practices: perhaps in some areas they are very conservative and LDCs have large daily reserves that they hold for contingencies and remain unused but could have been released in real time. This could result in underutilization of available pipeline capacity.  Unfortunately, the actual flows on the pipelines are not released in the public domain and it appears there needs to be more transparency on actual flows. If the data suggests the pipelines are consistently being underutilized, an actionable item would be to ensure better coordination between the LDCs and the electric markets of intra-gas day utilization of gas.  o Note that these issues implicate both state and federal jurisdiction. |
| 2 | Process Gas Consumers Group, Industrial Energy Consumers of America, and American Forest and Paper Association | Andrea Chambers | WGQ – End User | As noted above, there should be a method for improving the ISOs’ and RTOs’ forecasts for demand prior to the occurrence of a storm event and including an appropriate safety margin, a means for market participants to give feedback to the ISO or RTO when they disagree with the forecasts, and some ability to have either FERC or the local public utility commission to intervene when the forecasts appear too low to avoid any “unanticipated” demand.  Another issue that is of concern to AIP members is the lack of transparency as to the availability of capacity on intrastate pipelines. It is unclear where capacity that was contracted for on intrastate pipeline disappears to during a storm event or who it was allocated to. More information postings made by intrastate capacity operators would improve the ability of market participants to cope with extreme weather events.  For both interstate and intrastate pipelines, AIP suggests that situational awareness could be increased if an outside group, such as ICE, were to provide a transparent means for all market participants, including operators of electric generation, to be able to obtain data as to the current and anticipated operational status of pipelines on a regional or national basis through a single website as described in AIP’s response to Question 4. Such information would allow market participants to determine which pipelines are operating at or near capacity and where pipeline capacity might be available without having to check each pipeline individually. Tracking the operations of the pipelines on a regional or national basis would allow market participants to take actions to avoid constrained areas in some instances where there is more than one pipeline alternative. Additionally, this data would provide market signals regarding where pipeline capacity is needed and help incentivize new pipeline capacity to be developed. |
| 3 | Natural Gas Supply Association | Pat Jagtiani | WGQ – Producer | The following is a list of potential areas to consider for more information sharing:  • Generator Timely Alerts to Regional Operators. Generators and regional operators should establish mutually agreeable processes for timely alerts from generators when they encounter issues during an emergency event such as (1) the rare occasion that there is a potential reduction in firm gas supply or transportation commitments; or (2) a heightened risk that they may not be able to secure gas due to reliance on the daily spot market and interruptible transportation arrangements that may become curtailed.  • Regional Operator Awareness of Performance Risk and Contractual Commitments. NGSA agrees with the FERC-NERC report’s statement that RTOs should be aware of the types of contracts held by generators serving their region. In addition to receiving information directly from generation companies and monitoring pipeline EBBs for critical notices, regional operators could monitor FERC’s mandatory pipeline Index of Customers to gain a better understanding of contracting practices used by generators in their region. Also, during the forum, parties could explore what transport and supply information, if appropriately protected, regional operators and gas generators believe would assist in more thorough assessments of generator performance risk.  • Explore Best Practices for Gas Market Awareness. Seek best practices, information sharing and education among regional operators that have set up successful programs that gather and aggregate relevant natural gas information for their region. Encourage market participants to actively monitor natural gas production and model weather related impacts to aid in their advance planning.  • Increase Awareness of Remarketing Opportunities. Explore ways that all gas customers can increase their awareness of market opportunities for gas suppliers to remarket gas for customers that are willing to sell gas back into the market or reduce purchased volumes. We are uncertain how many gas customers readily consider reducing their purchased volumes, especially during extreme events.  • Increase Intrastate Pipeline Transparency. Assess whether actions are warranted by the appropriate regulatory authority to address whether intrastate pipeline transparency can be enhanced to prevent some of the issues experienced during Winter Storm Uri. For example, at the forum, participants could explore whether intrastate pipeline should implement EBBs to enhance transparency, and capacity release and flexible points rights, which would have assisted shippers during Winter Storm Uri.  • Waivers During Emergencies. Explore in advance with relevant regulators and stakeholders and, if possible, adopt emergency preparedness plans for implementing the following on very short notice during critical events:  o Jones Act waivers  o Short-term waivers of air emission limits  o Short-term waivers of RPS requirements  o Short-term waivers of pipeline quality specifications where, for example, gas processing plants could be temporarily by-passed, or higher heating value gas could be tolerated by a pipeline on a short-term basis to effectively increase capacity |
| 4 | Bureau of Economic Geology, University of Texas at Austin | Gurcan Gulen and Ning Lin | Other Market Participant/Observer | More transparency of market data is vital for improving the collaboration and knowledge share between the gas and power sectors. For Texas, the lack of transparency of intrastate pipeline and storage data does bring challenges in gaining a clear understanding of market dynamics, especially in an extreme weather event, like Uri. For example, intrastate pipelines control twice as much working gas storage capacity as interstate pipelines, which are regulated by FERC.  Furthermore, besides data transparency in the market, it is also important to recognize the lack of shared understanding of the market between gas and power in many regional markets. During Uri, there was increased collaboration across gas, electric, and other infrastructure value chain participants under the Texas Energy Reliability Council (TERC). Through discussion and interviews with local utilities, TERC acted as an active forum for information exchange during Uri. Although TERC was not providing any directives to any operators, the regular meetings provided information and status updates which were critical in decision-making during the winter storm. Deeper dialogue and active collaboration among critical sectors on selected topics need to continue, as a new norm of operation between the value chains. For example, such collaboration may help prioritize winterization actions as discussed in our response to Question 1. |
| 5 | MISO, PJM & SPP | Joshua Phillips | WEQ – IGO & Planner | Within the IRC comments filed in 2022 are several suggestions for improving data sharing and clarity. Additionally, the joint FERC NERC report on the event further details opportunities.  The issue of standardization of details associated with critical notices was raised during the standards request R21006, similarly the IRC raised these opportunities within their comments. It was presented at the joint meetings between the gas and electric industries, that each pipeline may implement their critical notices in a different manner provided they follow a general format outlined in the NAESB gas standards including headers, data sets, etc. During the presentations some notices contained specific locational information where others may have referenced a general area or simply their pipeline system. The causes of the limitation can be overly vague or point to a specific issue. It was also found that critical notices can be distributed as critical for things such as an annual requirement to update contact information. Lastly these notices are not available through a single portal, but a portal for each gas pipeline, further creating delays in accessing crucial information.  During critical times when seeking to expeditiously interpret impacts between the two industries, the challenge of sorting through the numerous notices has the potential to create significant delays. Additionally, these notices may exclude critical pieces of information such as location, which may even be expressed differently between gas pipelines.  Improvements to the format and information contained within the critical notice would enable more expeditious interpretation. Such enhancements could include geographical location details of the impact or a visual image, meters impacted by the notice, and enhancements to the Operational Flow Order (OFO) notice which could include tiers to denote the magnitude of the impact. Such a tiered approach could greatly enhance the notice such that a tier 1 may have no impact on delivery whereas a tier 4 notice could mean curtailments of scheduled firm service.  This could be modeled after what is currently done in the electricity industry using Energy Emergency Alerts (EEAs). In the electric industry, each entity is free to craft their conservative operations procedures leading up to an event in accordance with what suits the needs of their individual footprint. That said, when the most critical levels of an emergency are reached, the use of standardized EEAs come into play. EEAs establish uniform levels and expectations across all reliability entities. This ensures clear and consistent communication and action, minimizing the potential for human error and misinterpretation. In this manner, if this proposal were adopted by the natural gas industry, each pipeline would continue to retain flexibility for their individual OFOs leading up to and including all issuances other than those reserved for the most critical stages of the emergency event which would be standardized. |

| **Responses Submitted by October 10, 2022 – Question 4** | | | | |
| --- | --- | --- | --- | --- |
| **Question 4** | | Please provide other general comments and recommendations for the forum attendees to consider related to the topics identified for the October 21 meeting. | | |
| **#** | **Organization** | **Representative** | **Market/Segment** | **Comment & Specific Recommendation** |
| 1 | LS Power | Marji Phillips | WEQ – Generator | o Encourage states to have their LDCs formalize a reforecasting methodology for extreme conditions (real time) that reforecasts their demand from 1700 during the gas day, which is also the beginning of the super peak period in the electrical markets, through the end of the gas day. The methodologies, which may require state regulator approval, could also specify how the LDCs calculate their reserve margins and under what circumstances they release excess transportation and gas for resale after reforecasting.  o As noted above, facilitate cooperation among appropriate parties (individual utilities, RTOs, state, etc.), to develop a more granular understanding and identification of the scope of the problem related to natural gas unavailability during extreme conditions. |
| 2 | Process Gas Consumers Group, Industrial Energy Consumers of America, and American Forest and Paper Association | Andrea Chambers | WGQ – End User | For both interstate and intrastate pipelines, another approach that could be developed in addition to planning to build more capacity, would be a program that would allow demand response on gas pipelines so that market participants could enter pre-arranged deals to offer their capacity on a voluntary basis during times when a critical weather event is declared. While capacity reallocation is occurring currently through pipeline capacity release programs and asset management arrangements, AIP suggests that a committee of all stakeholders be formed to establish a special pipeline capacity plus natural gas swap or exchange on ICE or other such platform where pipelines, coordinating with replacement shippers, could identify open capacity and supplies and post it for bid in emergency weather situations. A critical weather event program like this could allow some efficiency and fairness in reallocation of capacity in an extreme weather event where there is high demand and limited capacity. |
| 3 | MISO, PJM & SPP | Joshua Phillips | WEQ – IGO & Planner | Enhancements to the reliable availability of gas during extreme events are critical for avoiding a future event which causes loss of life. There is no single enhancement that would prevent such future catastrophe, however by working together these industries can ensure gas and electricity are reliably delivered to meet the demand of consumers.  While much of this discussion is focused upon communication between gas and electric industry entities, regulators provide a crucial role for enhancing this reliability. We heard on the last call that contractual and regulatory obligations of gas suppliers can conflict with deliveries to critical electric generators which are typically short term and economic purchases. If electric generators purchased gas at higher and longer terms to improve their service priority, electric generators would not only have to increase electricity prices – but because of competing regulatory obligations may not ensure gas availability for them when resources are scarce.  It was discussed that gas contracts dictate deliveries and nearly all firm contracts were unimpacted, however when no electricity is available, industrial customers have no lighting for their facilities and residential customers lack power to operate the fans on a heating system. This dualistic reliance upon each other for reliable operations warrants further consideration and determination of which entity has the ability to redirect gas to ensure neither industry loses reliable operations. |









1. Letter from Gordon van Welie, President and CEO, ISO New England, to Hon. Jennifer Granholm, Secretary, United States Department of Energy at 1 (Aug. 29, 2022) [↑](#footnote-ref-1)
2. Id. at 3. [↑](#footnote-ref-2)
3. See NGSA (“region operators may want to consider whether changing the timing of day-ahead generator awards would assist gas generators in their region by giving them more timely notice about the amount of fuel they will need to purchase during the morning period when the gas market is most liquid. Late day award notifications force generators into the market when most gas has already been sold for the day (generally by 9am ET). This risks gas availability as well as higher priced purchases during illiquid periods. The gas industry does not ‘set’ a time for purchases. Many gas customers purchase on a monthly basis and the percentage sold in the daily market is generally completed in the early morning hours. This also holds true for gas pipeline scheduling where most capacity is scheduled during the timely gas cycle and later cycles are used more for balancing.”); Dominion Energy (“The ERCOT load shed event occurred on a Monday morning, which was the third day of a four-day holiday weekend. However, the vast majority of gas supplies were procured prior to the first day, of this holiday weekend, as the natural gas market predominantly traded four-day packages on that Friday before. Consequently, gas fired generators may not have purchased sufficient fuel because the next day electric market signal did not support the cost of the weekend gas supply package. By Monday morning, not only were incremental gas supplies not available, but the timing was outside the final pipeline nomination cycle, within that Gas Day.”) [↑](#footnote-ref-3)
4. Robert Walton, ‘Batteries aren’t going to do it’: NERC’s Moura calls for gas investment to maintain reliability, Utility Dive (July 21, 2022) (quoting John Moura, Director of Reliability Assessment and Performance Analysis), <https://tinyurl.com/3dj5e33d>. [↑](#footnote-ref-4)