Via email and posting

November 7, 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 – November 1, 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 24, 2022 soliciting general comments related to the agenda topics for the November 8, 2022 meeting. Late comments are highlighted.

| **Responses Submitted for November 8, 2022 Meeting – Question 1** |
| --- |
| **Question 1** | Expansion of natural gas infrastructure/capacity has been a solution offered by several participants during the Forum discussions.a) What are the barriers to building the additional infrastructure/capacity that may be helpful in supporting the Bulk Electric System?b) How can these barriers be eliminated? |
| **#** | **Organization** | **Representative** | **Market/Segment** | **Comment & Specific Recommendation** |
| 1 | Interstate Natural Gas Association of America (INGAA) | Christopher Smith | WGQ - Pipeline | The Federal Energy Regulatory Commission (the “Commission”) requires any company seeking a certificate under the Natural Gas Act to construct or modify interstate natural gas pipeline facilities to demonstrate that there is “need” for the project. Under longstanding practice, the Commission finds that a company adequately demonstrates need when it produces binding, long-term precedent agreements with unaffiliated parties for a substantial portion of the project’s capacity. Therefore, removal of obstacles that preclude entities with a long-term need for natural gas from executing such agreements would support the expansion of natural gas infrastructure. For example, if RTO/ISO rules do not sufficiently allow merchant generators to recover the cost of firm transportation services or otherwise deter investment in firm transportation, then the revision of those rules would help remove barriers to natural gas infrastructure expansion.Although the Commission finds precedent agreements sufficient to demonstrate need for a project (a practice that the D.C. Circuit Court of Appeals affirmed) testimony from entities that depend on natural gas is also powerful support for a project. INGAA encourages those entities involved in this proceeding—ISOs/RTOS, natural gas market participants, and electricity market participants—to advocate before the Commission for the long-term need for natural gas infrastructure to maintain electric reliability, to increase the electric grid’s resilience, and to reduce greenhouse gas emissions both by enabling retirement of higher-emitting generators and by supporting the integration of additional renewable generators.INGAA emphasizes that there is a critical need for additional natural gas infrastructure. According to the Commission’s recent winter assessment, New England will pay higher natural gas and electricity prices this winter due to constraints. California likewise faces constraints due to ongoing pipeline outages. Both regions would benefit from additional pipeline capacity.The actions described here will not remove all obstacles to the expansion of natural gas pipeline infrastructure, but they are important steps towards maintaining a reliable, affordable electric grid. |
| 2 | LS Power Department | Mark Spencer | WEQ – Generator | The expansion problem may be bifurcated to i) jurisdictions driven primarily by state policies – e.g., New York and New England states, that pose significant policy barriers to new infrastructure and ii) jurisdictions that are driven by economics – e.g., ERCOT.In areas driven by state policies, these policies are solidly entrenched and overturning them is not politically feasible. The interstate pipelines are fully subscribed, so the state regulators must determine if they wish to rebalance scarce transportation between the LDCs and electric generators in order to minimize societal harm during extreme weather.In jurisdictions driven by economics, expansions may occur if there are sufficient long-term prices signals to reward such investment. The existing paradigm, however, has been to expect the organized markets to send these prices signals, which they are not designed to accommodate. |
| 3 | Industrial Energy Consumers of America (IECA) | Paul Cicio | WGQ – End User | **I. Congress Needs to Give the FERC/NERC Responsibility to Ensure that there is Adequate Interstate Natural Gas Pipeline Capacity for Reliability of Natural Gas and Electricity Supply**Congress needs to give the Federal Energy Regulatory Commission (FERC) and the North American Electric Reliability Corporation (NERC) responsibility for ensuring that there is sufficient interstate natural gas pipeline capacity at peak demand for reliability of natural gas and electricity. No federal agency has this responsibility. No federal agency knows what pipelines are running at peak demand. Without ensuring that pipeline capacity is available, lives are at risk, as well as our nation’s economic and national security. We are already experiencing regional energy scarcity. Numerous pipelines issue operational flow orders and curtailments during the winter. Furthermore, the FERC/NERC cannot fulfil its mandate to ensure electricity reliability unless there is adequate pipeline capacity for natural gas-fired generation that is being used to displace coal-fired power generation units and because new storage technologies are not at scale to provide load balancing. Natural gas-fired generation is crucial to the transition to a low carbon electricity.[[1]](#footnote-1) On a regional basis, manufacturing companies cannot expand because pipeline capacity is not available. In the winter months, they are forced to run at reduced operating rates or be curtailed all together, creating havoc to supply chains. Recently, the Wall Street Journal reported that U.S. corporations are reshoring jobs.[[2]](#footnote-2) This is good news, but short lived unless we urgently expand natural gas pipelines. U.S. manufacturing cannot beat China without the infrastructure necessary to expand our facilities. The FERC’s responsibility needs to shift from being a regulator of pipeline permits to having responsibility to ensure that the pipelines that are needed will get built in a timely manner to secure our nation’s reliability and national security. Today, the FERC is reactive. With responsibility to ensure reliability, their role shifts to being pro-active. The current regulatory system is broken and has not adjusted to the accelerating changes of the market. For decades, the current system has worked well. When pipeline capacity was needed, pipeline companies filed permits to the FERC and for the most part, the pipelines were approved and built without much delay. That is no longer the case. Today, at every turn, politics and activists successfully slow and stop pipelines through legal action. New pipelines, justified on the basis of demand for natural gas, no longer get built. And, if they do, because of long delays, it is at a cost that is double or triple the original cost. These higher costs get passed onto us, the ratepayer, who are saddled with these costs for decades, increasing inflation. While EIA forecasts long-term growth for natural gas for industrial, power generation and for LNG exports, we note that Constitution (0.7 Bcf/d), Penn East (1.1 Bcf/d), Atlantic Coast (1.5 Bcf/d), Northeast Direct (1.2 Bcf/d) pipelines were all cancelled. Mountain Valley (2 Bcf/d) and Norther Access (0.5 Bcf/d) are both opposed and significantly delayed. We cannot have increased use of natural gas without increased pipeline capacity.**POLICY RECOMMENDATIONS****Give the FERC/NERC Responsibility to Ensure that there is Adequate Interstate Natural Gas Pipeline Capacity for Reliability of Natural Gas and Electricity Supply**-The FERC/NERC will monitor interstate natural gas pipeline capacity nationally for purposes of ensuring reliability and identify pipelines and areas of the country that need increased capacity. New pipeline permit applications inform this objective. This is consistent with GAO’s recommendation.[[3]](#footnote-3) *FERC should use available information, such as reports by transmission pipeline operators on service interruptions, to identify and assess risks to the reliability of natural gas transmission service.* -Require the FERC to take action to remedy reliability problems by expediting permits and construction and completion of the pipeline. Actions includes requesting use of Presidential emergency powers. This is consistent with but goes beyond GAO’s recommendation.[[4]](#footnote-4) *FERC should develop and document an approach to respond, as appropriate, to risks it identifies to the reliability of natural gas transmission service.*-Require the FERC/NERC to provide national oversight to ensure a smooth transition to decarbonization. For example, a pipeline serves multiple states with no coordination of the shutdown of coal or nuclear power plants and the addition of natural gas fired generation, which risks reliability and results in lack of pipeline capacity for manufacturing. Give the FERC/NERC the responsibility to coordinate with state agencies and if necessary, require that coal fired, or nuclear power generation units remain operating until pipeline capacity is available for all ratepayers. -Assure that there is adequate natural gas pipeline capacity available for manufacturing growth. Manufacturing companies cannot compete with utilities and LNG exporters for pipeline capacity. Manufacturing is unable to do long term firm pipeline contracts. If Congress wants manufacturing to grow, it must either always ensure that there is more capacity than demand or it needs to create a new program that sets-aside capacity for manufacturing growth. **II. Technical Conference on Federal-State Interstate Natural Gas Pipeline Coordination and Oversight is Needed**Action is needed to ensure that there is adequate interstate natural gas pipeline capacity for the manufacturing sector. Regionally, demand for natural gas power generation and LNG exports has reduced available pipeline capacity for manufacturing and new pipeline capacity is not getting built. Inadequate pipeline capacity is disrupting existing manufacturing facility operations and is preventing new investments and job creation. Reliability is a core issue. The situation is getting worse each year and has implications to our nation’s supply chain, inflation, national security, and the growing trade deficit. One hundred percent of IECA members are from the manufacturing sector. We encourage the FERC to hold a Technical Conference to examine the need for federal and state coordination and oversight of pipeline capacity, taking into consideration the siting of new natural gas-fired power generation, and the shutdown of coal and nuclear electric generation. Without action, more regions and manufacturers will be impacted. Furthermore, our nation cannot have electric reliability without natural gas pipeline reliability. Currently, no federal agency has responsibility for natural gas pipeline reliability.The technical conference will require participation by entities representing manufacturers, pipelines, electric utilities, state public service commissions, state government economic development officials, and others. Our member companies report that there are serious regional interstate natural gas pipeline capacity shortages that have resulted in an annual increase of pipeline operational flow orders that will eventually result in curtailments of supply to manufacturing facilities. This has resulted in higher natural gas cash-market prices. For example, the Transco Zone 5 January 2022 average price was $11.367 per MMBtu. On January 21, prices increased to $21.80 per MMBtu. Curtailments are also being reported on intrastate pipelines. Inadequate pipeline capacity, coupled with increasing demand from power generators and LNG exports, is disrupting our nation’s manufacturing supply chain. The problem is exacerbated during peak demand in the summer and winter seasons. When regional pipelines do not have the needed capacity to supply demand, manufacturing companies are the first to be impacted by gas-use restrictions, extremely high Gas Daily prices, and ultimate curtailment. Many manufacturers are deemed essential to the economy. However, when natural gas restrictions occur, only those users that absolutely need gas such as hospitals, residential homes, and entities able to afford the extremely high prices, such as LNG facilities and power generators, are first on the delivery list. High natural gas prices are not a concern for the electric or gas utilities because they can pass the costs onto their consumers via their fuel adjustment mechanism. High prices are also not a concern to LNG exporters who benefit from exceedingly high global LNG prices. For manufacturing, competitiveness is directly impacted by higher prices for natural gas and electricity. When confronted with a reduction of natural gas supply, manufacturing companies have limited options, none of which are satisfactory. They cut back manufacturing production rates or stop production all together, shift production to other sites across the country, or switch to backup energy sources like diesel, biomass liquor (paper companies), and coal or propane, if those options are available. Most companies do not have alternatives. We are dependent upon natural gas.[[5]](#footnote-5) **Setting aside the obvious and serious challenges of permitting, construction, and the completion of pipelines, there is a lack of oversight and planning by federal and state authorities.** For example, even though an interstate pipeline runs through several states, all of which are dependent upon the same pipeline, there is no coordination to ensure that decisions by one state are not negatively impacting another state. As long as there is excess pipeline capacity, this is not a problem. However, excess capacity no longer exists in several major pipelines. A case in point is Virginia, North Carolina, and South Carolina. We have observed that these state utilities have Integrated Resource Plans which have and/or plan to accelerate the decommissioning of coal-fired electricity generation plants and build significant natural gas combined cycle generators.[[6]](#footnote-6) In other regions, it may be nuclear plants. In all cases, electricity generators are building natural gas-fired power in order to reliably supply their needs and to provide backup power for intermittent renewable energy. All of these electric generators are using more and more pipeline capacity on Transco Zone 5, which supplies Virginia, North Carolina and South Carolina. The Cove Point LNG export terminal, which is at the end of Zone 5, is acquiring all the capacity that it can. **The result is periods of natural gas pricing that are five times higher than the nation’s average if we can get it at all.** During peak system demand, the region’s natural gas prices are now correlated to the global LNG market prices.The problem is that new natural gas electric generation capacity in Virginia is not being considered by North Carolina and South Carolina and vice versa. They are all acting independently, nor is LNG demand being considered. In all cases, the power generators and LNG export terminals are securing the capacity needed for their new facilities. However, none of the decisions made by electric utilities and LNG exporters take into account whether there is remaining pipeline capacity sufficient to supply the existing and future growth of the manufacturing sector in their states, and therein lies the problem. Unlike electricity, there is no federal oversight for natural gas pipeline reliability. For electricity, the FERC/NERC has the responsibility to ensure reliability. No federal agency has the authority or responsibility to monitor pipeline capacity rates. No federal agency knows which pipelines are running out of capacity at peak demand. Finally, another issue complicates manufacturers’ ability to secure needed pipeline capacity. The variability of manufacturing production changes monthly and from year to year, which limits some manufacturers from being able to do long-term firm natural gas contracts for pipeline service. LNG exporters and utilities have greater flexibility to make these long-term commitments. And, the continued rapid expansion of LNG exports has reduced and will continue to reduce available pipeline capacity for manufacturers unless new pipeline capacity is put in service.  |
| 4 | Natural Gas Supply Association | Pat Jagtiani | WGQ – Producer  | There are a number of barriers to building additional infrastructure including:**Funding and demonstration of need to support new expansions.** The competitive market structure in organized power markets creates a disincentive for generators to anchor new pipelines by signing long-term contracts that are needed to financially underpin new pipeline expansions. Gas-fired generator do not always have sufficient certainty that they will be adequately compensated for their gas purchases or the certainty about how often they will run, which makes it difficult to enter into long-term contractual agreements. Also, given that generators may not use their contracted levels often, there is reluctance to pay the “full freight.” NGSA’s previous comments detail suggestions for market-based changes in organized markets to facilitate the ability of generators to reliably contract for capacity including: -Consider the creation of new market-based services in organized markets that value key attributes such as ramping and frequency, which some regional operators are already doing. -Enhance capacity performance/pay-for-performance type programs to ensure they encourage the intended behaviors-Develop 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. -Hold educational sessions on natural gas market products available today to manage last-minute generator needs.-Look at 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. **Uncertainty about the level of pipeline capacity required to accommodate new generator usage patterns for ramping.** NERC should oversee an unbiased study, in conjunction with a diverse group of interests providing input, that would assist us in better understanding these requirements in each region. **FERC’s pending certificate policy.** FERC proposed policy statement has interjected a high level of uncertainty for potential project developers about what is necessary to get a project approved. FERC can help to mitigate this uncertainty by holding off on adopting any changes to the certificate policy until gas reliability alternatives are better identified or issuing a final policy statement that is more balanced and that relies on measures that are achievable and non-subjective. See NGSA’s comments on the proposed policy statement and the Draft GHG Policy statement below.-[NGSA and CLNG Joint Comments on the Draft Certificate Policy Statement](https://www.ngsa.org/wp-content/uploads/sites/3/2022/04/NGSA-and-CLNG-Joint-Comments-on-the-Draft-Certificate-Policy-Statement.pdf)-[NGSA and CLNG Joint Comments on the Draft GHG Policy Statement](https://www.ngsa.org/wp-content/uploads/sites/3/2022/04/NGSA-and-CLNG-Joint-Comments-on-the-Draft-GHG-Policy-Statement.pdf)**Growing anti-natural gas sentiment.** General anti-natural gas sentiment has grown and is likely to translate into high levels of public and policymaker opposition to projects. More must be done to ensure that the public and policymakers have a better understanding of the essential role natural gas will play through the transition. |
| 5 | The Process Gas Consumers Group (PGC) & the American Forest and Paper Association (AF&PA) | Andrea Chambers | WGQ – End User | One of the main obstacles appears to be that electric generators, for various reasons, do not sign up for firm pipeline transportation to serve their load during peak periods in order to ensure reliable transportation. In some cases, generators indicate that they do not sign up for such capacity because they cannot recover the costs of firm transportation from the wholesale electric markets due to the market’s design. In other cases, generators indicate that they would like to obtain capacity, but the pipeline has notified them that such capacity is not available at the time of their request. Another key barrier appears to be decarbonization policies being supported in the Northeast and the environmental challenges to the development and building of new infrastructure.These barriers can be overcome by compensating generators for holding transportation capacity in order to enable them to serve load at peak periods where such capacity is available, and by allowing generators to recovery such cost as a cost of ensuring reliable electric supply. Requiring RTOs, like ERCOT, to operate a capacity market, as opposed to an energy-only market, may also help if it can be done in a cost-effective manner. The current energy-only market appears to be failing to provide a market payment for the capacity that is needed to reliably serve load. Adding a capacity market could provide an additional source for such needed capacity; however, it would need to be structured to keep costs reasonable. RTOs and ISOs can also provide pay-for-performance payments to generators that take measures to ensure that generators can be called upon when needed for reliability. RTOs can also de-rate generation that does not have firm transportation, or on-site dual-fuel capability.Additionally, generators can request that the pipeline be incrementally expanded in order to serve their needs. The political and environmental challenges to the expansion of pipeline development can be addressed by educating the public of the need for natural gas-fired generation to support renewable generation and to ensure reliability. The need for increased ramping expected by the ISOs and RTOs as additional intermittent renewable generation is added to the system has been discussed in recent comments in Docket No. AD21-10, which comments are discussed in more detail below. As noted in the comments, natural gas-fired generation was historically available for dispatch for fast-ramping response. |
| 6 | SoCalGas | Jonathan Peress | WGQ – Distributor | The following comments and recommendations flow from the proposed forecasting recommendations in Q. 3 below which, in general, recommend more rigorous extreme weather event reliability and transmission planning. Presuming that such planning is undertaken by electricity balancing authorities and/or market operators: Electric market operators and gas transportation providers (including relevant LDCs) should identify needed upgrades to meet bulk power reliability needs under extreme conditions. As part of this “upgrade identification process” electric market operators should identify the specific generating facilities the upgrades are designed to benefit. An approach for compensating transportation providers for the needed upgrades should be adopted and included in the relevant electric market tariff.  |
| 7 | PJM, MISO, SPP & NYISO | Joshua Phillips | WEQ - Independent Grid Operator & Planner | This is an extremely broad question. We would note that the current system of determining need for new capacity based on precedent agreements may not capture all of the drivers of need for pipeline expansion. The transmission system is expanded based on specific planning drivers that focus on future demand and the overall ability of the grid (and segments of the grid) to reliably deliver electricity based on future demand. The electric transmission grid would be haphazardly expanded if the sole driver of need was determined based on precedent agreements where individual loads would be committing to fund the transmission expansion. The use of precedent agreements may not be a good fit for generators that do not have the assurance of always being dispatched. Nevertheless, this is a regulatory issue for FERC. |

| **Responses Submitted for November 8, 2022 Meeting – Question 2** |
| --- |
| **Question 2** | Please provide general comments and recommendations concerning the following related to information sharing:1. What information is currently not shared between interstate pipelines, LDCs, gas-fired power generators, and the ISO/RTOs that would be helpful in situations of constrained capacity/unanticipated demand?
2. What information is currently not shared between intrastate pipelines, LDCs, gas-fired power generators, and the ISO/RTOs that would be helpful in situations of constrained capacity/unanticipated demand?
3. What are the barriers to sharing the information, and how can they be eliminated?

d) How could/should the information be shared? |
| **#** | **Organization** | **Representative** | **Market/Segment** | **Comment & Specific Recommendation** |
| 1 | Interstate Natural Gas Association of America (INGAA) | Christopher Smith | WGQ – Pipeline  | While INGAA is open to discussions regarding additional information exchanges during periods of constrained capacity or unanticipated demand, we note that the Commission already has taken important steps to facilitate these exchanges. Most notably, the Commission issued Order No. 787 to “help maintain the reliability of pipeline and public utility transmission service by permitting transmission operators to share information with each other that they deem necessary to promote the reliability and integrity of their systems.” Order No. 787, 145 FERC ¶ 61,134, P 1 (2013). The Commission “provide[d] explicit authority to transmission operators to share non-public, operational information with each other for the purpose of promoting reliable service or operational planning on either the public utility or interstate natural gas pipeline’s system.” Id. at P 41. Order No. 787 built upon prior measures like NAESB Wholesale Electric Quadrant (WEQ) Standard 011-1.6, which “requires that ISOs, RTOs, and other independent system operators establish written operational communication procedures with an appropriate interstate natural gas pipeline to be implemented when an extreme condition occurs.” Id. at P 10.The steps described above have led to extensive and frequent communications among interstate natural gas pipelines and ISOs-RTOs regarding system operations, capacity, and reliability. In fact, INGAA just held its annual pre-winter meeting with the ISOs and RTOs. Coordination efforts extend beyond communications between RTOs/ISOs and pipelines to include communications among all relevant stakeholders. ISO-NE, for example, recently described its “industry leading gas-electric coordination process” which it developed through its “long history of coordination between gas pipeline and electric system operators.” This process includes “routine coordination efforts with interstate natural gas pipelines and annual assessment of critical natural gas infrastructure facilities” because “direct communication with gas control is key to understanding the indications from all reports and displays available to operators.” A NERC official similarly explained that “[e]very ounce of efficiency has been squeezed out of [gas-electric coordination]. And coordination really doesn’t let more gas flow.”[[7]](#footnote-7) Moreover, interstate pipelines currently provide substantial information to the public on operationally available capacity, planned and unplanned maintenance activities, and critical notices (including OFOs, operational alerts, and force majeure events) on their Commission-mandated internet websites. Interstate pipelines are obligated to post this information as soon as it becomes available for all shippers and other interested stakeholders to see; interstate pipelines will update these postings as operational conditions evolve. Pipelines also post information on their websites updating shippers of conditions on the systems. As well, pipelines can have one-on-one discussions with their shippers regarding the shipper’s individual contract. Outside of the protections of Order No. 787, however, interstate pipelines must ensure that communications do not unduly discriminate, either in favor of or against, one shipper over another. INGAA reiterates its openness to discussions regarding additional information exchanges, but additional communication will not create the capacity that is needed to reduce physical constraints and to address the electric grid reliability problems that are facing the country. |
| 2 | LS Power Department | Mark Spencer | WEQ – Generator | As noted in our last meeting, there is not a lot of transparency around actual gas flows. We observe that many LDCs do not update their nominations after the end of the timely cycle, which suggests that they may retain underutilized capacity. In certain circumstances pipelines must hold capacity for no-notice service in addition to what is nominated. Absent the pipelines releasing actual flow data for various points on the mainlines - e.g., compressor stations, etc., and flows to the major laterals, it is impossible to understand how efficiently pipeline capacity is utilized under extreme conditions. It is difficult to have a discussion on electric-gas harmonization without having the actual flow data and comparing it to the operational capacity of the pipelines. |
| 3 | CAISO | Shawn Grant | WEQ – Independent Grid Operator & Planner | The CAISO does not experience information sharing issues with the intrastate LDCs. The CAISO has worked with the LDCs over many years to build trust and understanding between all entities to ensure energy can be delivered safely and reliably to all of our customers. The CAISO believes effective communication can be established between the electric and gas industries utilizing region-specific coordination opportunities without standardizing communications at the national level. The CAISO and LDCs utilize Non-Disclosure Agreements (NDA) that allows us to share information in a manner that can benefit all parties and maintain system reliability. This NDA framework allows for multiple points of coordination: The CAISO provides access, through a secure portal to each LDC, to a daily gas burn forecast for each hour of the day after the Day-Ahead Market has run. The CAISO also provides D+2 information and Real-Time Fifteen-minute market information to each of the LDCs through the same portal. This information provides the LDCs with calculated gas volumes for the electric generation they serve based on the electric market awards for the next day and adjustments to reflect conditions in Real-Time. The CAISO also created multiple natural gas nomograms that can be activated in the Day-Ahead Market or in the Real-Time Market if the LDCs deem it necessary due to their system conditions. These nomograms serve as a tool to optimally utilize gas availability restrictions by gas-fired generation resources served within defined gas zones.There are nightly communications between the CAISO system operations control room and each LDC’s gas operations control room to discuss current system conditions and any changes that may impact generation or gas usage for the next day. If there are real time events on the gas or electric side, communications between the control rooms are established to help facilitate the issues and reduce the impacts to both electric and gas reliability. Weekly outage meetings are held to discuss future gas facility outages that may impact generation coming up in the next week and next year. These meetings help facilitate planning and coordination on both the electric and gas side to maintain system reliability. |
| 4 | Natural Gas Supply Association | Pat Jagtiani | WGQ – Producer  | NGSA does not have any specific ideas to offer in response to this question, but we welcome further engagement in conversations that pursue updated and/or better methods for additional information sharing. |
| 5 | The Process Gas Consumers Group (PGC) & the American Forest and Paper Association (AF&PA) | Andrea Chambers | WGQ – End User | There is no sharing of capacity information with the end-users of the interstate and intrastate pipelines of the real-time or near-time operations of natural gas pipelines. This is important information that should be shared with end-use customers, such as industrials, who pay for the pipeline capacity. This information is important for the safe operation of plants. For example, reductions to pressures on pipelines can cause equipment to be irreparably harmed. Steel production plants can incur severe damage and workers can be harmed when equipment is shut-down or not able to run at the appropriate level. There needs to be more of an opportunity for customers to share information about what equipment can safely reduce its energy demands without jeopardizing safety and causing property damage in the event of a need to curtail. However, we still believe the better approach is to plan ahead to ensure electric generators have the natural gas pipeline supply and capacity that they need to avoid curtailment. The lack of information is not just limited to transportation capacity. There is also no coordination, or visibility, of production showing up at gathering or receipt points. This is analogous to an electric market with no direct visibility to generation, and, instead, using transmission as the lead indicator for available generation. During critical operations, users need to account for the non-firm nature of a lot of gathering and midstream facilities needed to deliver production to contracted receipt points. Encouraging the voluntary posting of information about operational problems being experienced by operators of wellhead and mid-stream facilities would help end-users respond to these extreme weather events and increase safety.Having information on real-time or near-time pipeline operations (e.g., what percentage of the pipeline’s design capacity is full and whether the pipeline is expected to be required to curtail load) and information on the gathering and receipt point production issues, and other expected natural gas supply and deliverability problems could enable voluntary demand response and allow for time to prepare for a reduction in supply where possible. Industrials are interested in voluntary demand reduction programs for natural gas similar to what exists for the electric industry, provided that industrials can be compensated for their transportation and gas supply. In such a case, industrials would also need agreed-upon procedures so that any voluntary reductions occur in a manner that does not put workers or property at risk. This information on impending operational or delivery issues could also provide important data to provide market signals as to where more pipeline transportation capacity or storage capacity is needed to justify building more pipeline capacity or storage where it is important to provide reliable electric generation. Industrials also suggest that pipeline operators need better communication protocols with shippers that are over-taking their natural gas nominations and requesting that they stop or put more natural gas into the pipeline in order to avoid the pipeline having to call an Operational Flow Order and having to curtail all shippers.Another barrier faced during Storm Uri was the lack of sharing of hourly meter data to ensure usage was reduced as much as possible when a customer wanted to reduce their consumption. It is often cost-prohibitive for customers to install telemetry for hourly meter readings, and, during a storm event, customers may have to send workers out in the weather to read the meters which puts them at risk. |
| 6 | Texas Competitive Power Advocates (TCPA) | Michele Richmond | WEQ – Generator | What information is currently not shared between intrastate pipelines, LDCs, gas-fired power generators, and the ISO/RTOs that would be helpful in situations of constrained capacity/unanticipated demand?-Operational Capacity Data. Intrastate pipelines should be required to publicly post operational capacity data, similar to interstate pipelines. This would include capacity types (design, operational, scheduled, available) for each system receipt, delivery, interconnection, and major flow point (i.e., compressor stations, pooling points). This basic level of transparency would allow power generators and other end-users to better assess supply risks and make decisions regarding supply strategies.-Customer List including all firm shippers and capacity holders, as well as their pipeline contracts, with applicable receipt and delivery points, contracted capacity, rates, and contract term. Providing such a list improves transparency by identifying potential counterparties on a given intrastate system. This allows willing buyers and sellers to negotiate directly with each other for supply without being captive to negotiating only with pipeline marketing entity. Lack of proper code of conduct rules allows intrastate pipeline marketing function or affiliate to have advantaged positions over non-affiliated sellers. -Complete list of pipeline receipt and delivery points, and their operating capacity. This would help level the playing field in contract negotiations between shippers and pipelines, while allowing shippers to better negotiate receipt and delivery points directly with producers/suppliers and storage operators, without restriction of pipelines and their marketing functional group or affiliate.-Operational issues that impact pipeline capacity or reliability should be publicly posted so that all market participants can be made aware of the overall system impact in Texas. For example, a pipeline constraint on one pipeline may impact customers on other pipelines. Power generators may shift their fuel supply from one pipeline to another due to pipeline constraints, causing operational issues on pipelines or regional power production facilities.What are the barriers to sharing the information, and how can they be eliminated?State regulators do not require intrastate pipelines to post operational data; whereas, FERC requires interstate pipelines to post operational data. Most states lightly regulate their intrastate pipeline markets. These regulators rely on market competition to “self-regulate” the competitiveness of their intrastate pipelines. However, in areas where there is little or no competition, pipelines often take advantage of their market power by charging unreasonable rates and creating artificial barriers for gas sellers and power generators to contract directly with one another. During extreme weather events, only the pipeline can provide the necessary supply and delivery services required for electric generators to respond to hourly demand requirements. These non-competitive behaviors negatively impact power generation reliability, while allowing these pipelines to extract windfall profits. These costs are ultimately passed on to electric consumers and cannot be hedged, even by the most sophisticated electric consumers.How could/should the information be shared?Intrastate pipelines should be required to operate Electronic Bulletin Boards (EBB), similar to their interstate pipeline counterparts, such that pertinent information is publicly available. |
| 7 | SoCalGas | Jonathan Peress | WGQ – Distributor | What information is currently not shared between interstate pipelines, LDCs, gas-fired power generators, and the ISO/RTOs that would be helpful in situations of constrained capacity/unanticipated demand?The wholesale gas market design currently does not and yet should efficiently formulate transparent intraday prices based on available market conditions. The net effect of said intraday price formation infirmities is to mute or diminish price signals for supply and infrastructure to resolve constraints. What information is currently not shared between intrastate pipelines, LDCs, gas-fired power generators, and the ISO/RTOs that would be helpful in situations of constrained capacity/unanticipated demand?During periods of constrained demand, power generators should be providing transportation providers with their expected hourly takes based on the day ahead market results. While recognizing that the cleared market output may be altered during extreme weather (and unanticipated demand), it would provide a baseline for allocating constrained capacity. -- Wholesale electric market tariffs in some regional markets, address information sharing with pipelines. Similar tariff provisions should also be included in retail gas utility tariffs insofar as they provide transmission level service to generators. Put another way, pipelines and gas utilities have contract privity with their generator customers such that information sharing can and should be more facility specific and granular. It can be shared through electronic data transfer. |
| 8 | PJM, MISO, SPP & NYISO | Joshua Phillips | WEQ - Independent Grid Operator & Planner | Coordination work between pipelines and RTOs has vastly improved over time as a result of FERC Order 787 and dedicated communications established between pipelines and RTOs. However, despite Order 787 some pipelines still feel constrained to only release system information to the RTOs at the same time that information is released to customers despite Order 787 not so requiring. Communication between RTOs of system conditions occurs all the time without a ‘pre-condition’ that information can be shared only contemporaneous with its being made public as that would inhibit the kind of real time communications that are important to ensure reliability between adjacent systems.Improvements to existing notices and communications, could be made through a more common approach with regards to locational information and reasons for the system impacts to the gas network being included in those communications.An area that is ripe for future discussion relates to better coordination of the overall baseline planning as well as interconnection queue processes of RTOs/ISOs as it relates to the siting of natural gas generation and related considerations of both future pipeline and grid expansions. Additional work on coordination in the planning sphere would be helpful particularly as the FERC is encouraging long term scenario-based planning. PJM has pressed FERC to include enhanced reliability/resilience planning as part of that new planning process. Involvement and coordination with the pipeline industry in the planning sphere could enhance the robustness of future expansion decisions on both the pipeline and grid side of the equation. As raised previously, a ripe area for this NAESB effort would be increasing the transparency around the secondary market for release of capacity as electric generators utilize that market as one tool in meeting their obligations to the RTO/ISO. |

| **Responses Submitted for November 8, 2022 Meeting – Question 3** |
| --- |
| **Question 3** | What changes could/should be made to the current forecasting processes to accommodate constrained capacity/unanticipated demand events that may occur? |
| **#** | **Organization** | **Representative** | **Market/Segment** | **Comment & Specific Recommendation** |
| 1 | Interstate Natural Gas Association of America (INGAA) | Christopher Smith | WGQ – Pipeline  | For practical purposes, electricity moves instantaneously between two points. Natural gas, by contrast moves slowly through the interstate pipeline grid, at approximately 15-20 miles per hour. Pipelines can simulate instantaneous movement of natural gas through “line pack,” which is the inventory of natural gas within the pipeline. Line pack supports the operation of the pipeline from hour to hour; however, it does not create additional capacity on the pipeline.Pipelines must carefully manage line pack because if line pack is not reasonably stable across the pipeline system, the resulting fluctuations affect delivery pressure and, in extreme circumstances, can impact system integrity. In other words, the pipeline operator seeks to replace natural gas drawn out of the pipe by its customers with timely injections of new gas to maintain ongoing flows, pressures and gas velocity. Accordingly, pipelines benefit greatly from electric demand forecasts that not only include the volume of gas needed to satisfy demand for electricity, but also the physical points from which the requisite natural gas-fired generators will draw natural gas, the time at which those generators will begin drawing gas, and the length of time over which those generators will draw gas.The last data point is critical. Pipelines have designed their systems to meet firm shippers’ peak demand assuming the shippers will use the full amount of capacity for which they contract at an even rate over the course of a single day (i.e., a ratable 1/24 flow). If there is spare capacity on a pipeline, the pipeline might also offer services authorizing non-ratable flows, and many do. Reliable receipts of new gas as scheduled by pipeline customers, careful management of line pack, and well-planned storage operations, combine to enable non-ratable flows for limited periods. Sustained non-ratable flows can threaten system integrity and cannot be “assumed” to be available by one or more pipeline shippers on a unilateral basis.INGAA continues to encourage the development of incentives for natural gas-fired generators to procure firm transportation services. When contracting for capacity, it is critical that generators forecast not only the volume of natural gas that they need to run if called upon, but also the locations where their gas supply will be tendered into the pipeline, and the length of time over which they will need that volume. If generators forecast the need for non-ratable flows—to quickly ramp up when renewable generators unexpectedly stop operating for example—then the generators will need to contract for excess capacity to enable non-ratable flow. Pipelines can offer tailored services to generators that include non-ratable flows if the pipelines have capacity or if the generators execute precedent agreements that would support the system modifications necessary to be able to offer an expansion of capacity. |
| 2 | Big Data Energy & Business Laboratory | Cade Burks & George Danner | RMQ - Retail Electric Service Provider/Supplier | We have been a participant in the series of meetings regarding Gas Electric Harmonization for the past several months and have observed the discussions with keen interest. We have also studied the FERC/NERC Report on Winter Storm Uri. We have taken particular notice of comments from the respondents and the panel regarding the nature of the “math problems” that lie within the goal of harmonization. We would like to express a rather creative solution to that range of math problems, which includes forecasting as the survey question indicated.We believe that fundamentally the challenge of GEH is a problem of working out a system of policies and processes that: 1) works to the benefit of the network’s varied customers under all conditions, 2) allows the operators and asset owners within the value chain to earn a fair profit correlated to their added value, and 3) withstands any conceivable disruption due to unplanned events. This to us is a math problem, because we can use math and data to create a replica of a gas-electric system and then test this replica under a microscope in slow motion in carefully controlled laboratory-like conditions. What we are referring to here is a computer model, a simulation, a so-called Digital Twin of the Gas-Electric system.This same kind of policy formation using models has been done with great success in many contexts. Right here in NAESB’s backyard, models were used to resolve policy disputes among regulators, state agencies, and private firms regarding the expansion of the Houston Ship Channel. We propose to turn the power of data and analytics toward this very important and unique challenge presented by the complex aspiration of GEH. It should be noted that anything as complicated as GEH will be unlikely to be solved with a simple intervention, but rather with a set of interventions large and small carefully coordinated. **That set of optimal interventions is equally unlikely to be arrived upon solely using human intuition and experience.**We would envision building a model of a portion of the network and running a wide range of experiments with it. These could involve added infrastructure, nomination procedures, interoperation protocols, new derivative transportation products, optionality, changing dysfunctional incentive structures, and the like. Stress testing, future-proofing, and scenario planning are also apt terms to refer to certain use cases for the model that are particularly appropriate for the “unanticipated demand events” mentioned in the survey question. We also foresee that the model will be used in an on-going fashion to aid in problem-solving for future problems that are not even defined today.An example of an operational model for an extreme weather event would include near real time data feeds from pipelines and generators for the ISO to assist in balancing the grid. In the Southwest Power Pool (SPP) case during Winter Storm Uri, the normal communications of phone calls and pipeline bulletin boards is not sufficient when real time data is needed from all pipelines and generators in their territory for managing the grid. The operational model would consume data feeds like pipeline critical notices, pipeline scheduled quantity (cuts), pipeline capacity, generation forecast, generation natural gas run rate, weather forecast and other potential sources. The natural gas supply, natural gas demand, electricity generation could be simulated by the model for operational decision-making much more rapidly than phone calls and bulletin board look ups. The model would play out a “day-in-the-life” type of portrayal of network operation moment by moment, under the conditions set by the user, then report a set of summary Key Performance Indicators (KPIs). Most interesting in this type of analysis is so-called A/B testing where we simulate the operation of the networks twice—once as a base case and the other by changing just one variable. In this way we isolate the effect of that one policy, process, or asset change to assess its sole implications. The simple act of experimenting with a model like this will create a provocative outcome that stimulates focused debate among the stakeholders. We believe that supplementing the underway discussions with a data-driven approach helps strengthen and inform both parallel workstreams. Should this idea in concept have any merit among the stakeholders, we would propose to better define what such a model might look like—its inputs, outputs, data, scope, and other details of its design prior to launching into any development efforts. |
| 3 | Natural Gas Supply Association | Pat Jagtiani | WGQ – Producer  | Forecasting is important, but it does not take the place of ensuring that advance arrangements are in place for gas generators to be able to procure what is needed when they are called upon. |
| 4 | The Process Gas Consumers Group (PGC) & the American Forest and Paper Association (AF&PA) | Andrea Chambers | WGQ – End User | Historically, where there have been reliability issues (e.g., California Energy Crisis of 2001-02, Uri Storm), there has been evidence that either the LDCs or the RTOs had incentives to underestimate/or not overestimate load forecasts in order to achieve the least cost dispatch and or to match historical load profiles. We recommend that the RTOs/ISOs be encouraged to modify their load forecasting in times when there is an extreme weather event that could exceed historical use patterns, in order to recognize that additional generation may need to be available to serve an increased load in a reliable manner in the Day-Ahead market, and at potentially lower costs than the real-time dispatch of generators, who must then purchase natural gas in real-time, which increases their variable costs. |
| 5 | SoCalGas | Jonathan Peress | WGQ – Distributor | The following recommendations are derived from a recent WECC staff report entitled, The Year 2030 Extreme Weather Event Study Report (April 2022), which quantified and projects potential loss of load due to extreme weather events. (See, [Final ENE Report (wecc.org)](https://www.wecc.org/Administrative/ENE%20Report%20Final%20Report.pdf))-Electric market operators should evaluate risk of unserved energy during extreme events as part of planning studies considering both load and generation. -Reliability planning and operating entities should consider further analysis of reserves and ramping requirements to withstand extreme events. -Reliability planning and operating entities should consider extreme events when performing in-depth studies related to transmission congestion.-Reliability and transmission planners should consider simulating extreme events in planning studies and monitor system voltage performance. -Electric market reliability committees should evaluate and coordinate the availability of extreme natural event assumptions and data being used for reliability assessments. |
| 6 | PJM, MISO, SPP & NYISO | Joshua Phillips | WEQ - Independent Grid Operator & Planner | The pipeline planning processes are not nearly as transparent as those of the electric industry. A presentation from individual pipelines on their longer-term reliability planning would be helpful as part of this process. Also, a discussion on the use and limitations of line pack during stressed conditions and at other times would aid the discussion.Consideration could be given to the establishment and allowance for pipelines to build in reserve capacity within expansion projects to account for contingencies that can and do occur when faced with constrained transportation conditions. |

| **Responses Submitted for November 8, 2022 Meeting – Question 4** |
| --- |
| **Question 4** | Recognizing that there are costs associated with providing increased reliability of the natural gas infrastructure system, how could/should those costs be addressed? |
| **#** | **Organization** | **Representative** | **Market/Segment** | **Comment & Specific Recommendation** |
| 1 | Interstate Natural Gas Association of America (INGAA) | Christopher Smith | WGQ – Pipeline  | INGAA emphasizes that the interstate natural gas pipeline system is reliable. A study determined that fewer than 100,000 natural gas customers nationally experienced disruptions in 2016 compared to 8.1 million Americans who experienced power outages during that same period. From 2006 through 2016, pipelines delivered 99.79% of “firm” contractual commitments to transportation customers at the primary delivery points specified in their contracts. Even during more recent extreme weather events, interstate natural gas pipelines delivered as expected.[[8]](#footnote-8) Many participants in this forum have mentioned OFO notices as a point of concern. Pipelines rely on these notices to ensure integrity of operations and to honor contractual commitments. OFOs are not curtailments; they direct shippers to flow the gas to which they are contractually entitled and no more. In short, OFOs are not evidence of a pipeline reliability problem, but rather demonstrate the efforts undertaken by pipelines to ensure reliability for firm service shippers, in the face of extraordinary action by other shippers.It is critical that, in pursuing solutions, we do not mischaracterize the problem. We must focus on the threat to the electric grid’s reliability arising from barriers to natural gas-fired generators’ purchase of firm transportation rights and adequate natural gas commodity to support their intended operations.INGAA further notes that any costs associated with increasing electric reliability should be allocated to those who benefit from such reliability – electric customers. The interstate natural gas market model is built on a no-subsidization policy, i.e. any pipeline expansion must be paid for by the shippers that benefit from such expansion. Expansions cannot burden system shippers with costs. This policy has resulted in transparent market signals, efficient contracting practices, and the reliable natural gas transportation services described above. |
| 2 | Enchanted Rock | Joel Yu | WEQ – Technology or Service Company | Enchanted Rock proposes a well-established, economically efficient, and highly resilient strategy for critical gas infrastructure for consideration. In cases where production and transmission facilities rely on electric power for operations, microgrids, particularly gas-fired technologies that can draw from on-site gas supply, can serve as a low-cost backup power solution during grid outages. When the site is operating on grid power, the microgrid can operate to provide valuable services back to the grid, reducing the net cost of the system to the host customer, in most cases lower than the cost of traditional diesel backup power solutions. In Texas, gas supply and transportation companies already have experience providing grid services through ERCOT’s Emergency Response Service, though many were found to be participating without the capabilities in place to maintain service during a call for load reduction. (See the UT Austin Report on Winter Storm Uri @ page 9.) Since the Winter Storm Uri, ERCOT stakeholders have developed requirements for critical facilities that participate in the program to have backup power solutions in place to ensure continued operations while dropping load from the grid. (See NPRR1087, which was approved in late 2021.)By supplementing grid power with resilient, locally fueled backup power, Enchanted Rock’s customers achieve 99.999% power reliability. We currently operate over 250 resiliency microgrids with over 700,000 run hours, serving a range of critical facilities, including water utilities, military bases, universities, hospitals, and manufacturing. Our generation technology can operate at low gas pressures, down to 5 psi, and is not subject to the refueling risks associated with trucked diesel during wide-scale, long-duration emergency events. Because these microgrids run for few hours in the year and have extremely low emissions levels, they are not subject to the same air permitting challenges that require the electric compression in the first place. The deployment of resiliency microgrids by natural gas facilities would create a virtuous cycle of benefits—supporting greater gas system resiliency in support of electric generators broadly and providing additional resilient, dispatchable resources for ERCOT to call upon in times of grid stress. Given the widespread, public benefits of such a strategy, Enchanted Rock would recommend that jurisdictional entities develop resiliency regulations to require the evaluation and deployment of strategies to operate through extended power outages and/or incentives to support greater deployment of resiliency strategies like microgrids by the gas production and transmission facilities. Policymakers should also consider relief for rural areas that may want to access the gas system to support economic development. |
| 3 | LS Power Department | Mark Spencer | WEQ – Generator | For electric generators, firm transportation is akin to an insurance product that mitigates tail end risk. Consequently, electric generators should have cost recovery mechanisms substantially similar to those afford to LDCs to recovery their costs. The first step is for stakeholders to define the desired level of reliability through coordination between vertically integrated utilities and their regulators, and the RTOs and the state(s) that participate in their regional markets. Ideally, there would be various scenarios across the spectrum that demonstrate the cost associated with more or less reliability. Second, using such an analysis, a cost-benefit decision must be made and then the utility or RTO can procure the necessary resources to meet this standard. In this context, regulators can determine if requiring firm fuel is an appropriate remedy and states can then approve pass-through costs and the RTOs can impose obligations with commensurate compensation for firm fuel. |
| 4 | Natural Gas Supply Association | Pat Jagtiani | WGQ – Producer  | Market-based solutions provide the best means by which to allocate costs. However, it is possible that the number of state subsidies in place to support climate targets are impacting the ability of organized markets to effectively procure those assets that are required for reliability. If regional power markets are unable to make sufficient design enhancements that can support such expansions, competitive asset sharing mechanisms for attaining key reliability assets such as gas storage may need to be temporarily considered to avoid any significant disruptions in service. |
| 5 | The Process Gas Consumers Group (PGC) & the American Forest and Paper Association (AF&PA) | Andrea Chambers | WGQ – End User | Recent filings by RTOs and ISOs in FERC Docket No. AD21-20 indicate that there is an increased need for dispatchable fast-ramping resources to provide ramping capability due to the increase in the levels of intermittent renewable resource output, particularly solar and wind generation, in order to balance variations and volatility in output of intermittence resources. To the extent that the increased costs are needed to support ramping due to the need to increase reliability of renewable generation, these costs should be included in the costs of operation of these electric generators. |
| 6 | Texas Competitive Power Advocates (TCPA) | Michele Richmond | WEQ – Generator | Most intrastate pipelines do not operate under a tariff with a cost-based rate structure. They rely on contracts with individually negotiated rates. The cost of implementing an EBB should be minimal since most of the major intrastate pipelines also own interstate pipelines and therefore already have the IT infrastructure and knowledge to implement these systems.  |
| 7 | SoCalGas | Jonathan Peress | WGQ – Distributor | The current focus on gas system cost recovery for grid reliability exclusively from rates charged to electric generation customers, when dispatched, is not sustainable. A reservation charge applicable to electric utilities covering LDC costs to ensure electric grid reliability should be considered to ensure investment recovery.  |
| 8 | PJM, MISO, SPP & NYISO | Joshua Phillips | WEQ - Independent Grid Operator & Planner | Reliability upgrades on the electric side are assigned on a ‘beneficiary pays’ approach. Within several ISOs and RTOs, the cost allocation matter has been settled with reliability upgrades above a certain voltage level being socialized RTO-wide with reliability upgrades at lower voltage levels being assigned based on flows on the system. Similar models could be explored for the pipeline industry through analyzing existing FERC precedents on the electric side and the degree to which they may be transferable to the gas side. However, this question is a regulatory question. |

| **Responses Submitted for November 8, 2022 Meeting – Question 5** |
| --- |
| **Question 5** | Are there contractual terms or policies that present a barrier to responses in situations of constrained capacity/unanticipated demand? |
| **#** | **Organization** | **Representative** | **Market/Segment** | **Comment & Specific Recommendation** |
| 1 | Interstate Natural Gas Association of America (INGAA) | Christopher Smith | WGQ – Pipeline  | With respect to interstate natural gas pipeline transportation, contractual terms and policies do not drive the electric grid reliability problems at issue in this forum. Instead, these problems arise from flaws in electric markets that deter natural gas-fired generators from purchasing the type of service that they need. Specifically, the existing wholesale electricity market design may prevent advance contracting and discourages natural gas-fired generators from holding firm gas transportation rights. In our comments for the October 21 meeting, INGAA noted that shippers may nominate seven days a week during five daily cycles. Each pipeline’s tariff dictates the priority of service for each nomination, and the pipeline will review the tariff and the shipper’s contractual rights when scheduling nominations. Shippers with firm transportation rights can “bump,” or take priority over, shippers with interruptible transportation rights during four of the five daily cycles. (Intraday 3 is the exception.) FERC policy dictates that shippers with firm transportation cannot bump shippers with lower priority firm transportation rights, nor can shippers with interruptible transportation rights bump shippers with lower interruptible transportation rights.There are no contract terms or policies that prevent natural gas-fired generators from obtaining pipeline capacity during periods of constrained capacity or unanticipated demand. If the natural gas-fired generators hold primary firm transportation rights and nominate during the Timely cycle, they will be scheduled and be able to rely upon their transportation capacity, absent any unforeseen and unlikely capacity reduction. If the generators acquire capacity through the secondary capacity release market, and they have “secondary” point capacity, they shall be scheduled at their delivery point assuming there is sufficient capacity at the point. The “barriers” are (1) wholesale electricity market designs that often deter advance contracting and the purchase of firm transportation rights and (2) day-ahead awards that are issued with insufficient lead time to participate in the Timely pipeline nomination cycle.Notwithstanding contract terms, INGAA members take significant actions to deliver as much natural gas through their pipelines as possible, within commercial and operational limits. Pipelines deliver natural gas to natural gas-fired generators—which typically do not contract for firm transportation services—through either capacity release or asset management transactions. Depending on how the pipelines’ firm shippers are utilizing their capacity at the time, pipelines may be able to offer non-ratable flows to shippers, including gas-fired generators, even in the absence of a contractual obligation to do so. Pipelines might also, among other things, accept nominations outside of NAESB cycles, to the extent such pipelines’ tariffs provide for such nominations.Rather than adjust generators’ incentives so that the generators contract for pipeline services that will support their intended operations, some stakeholders have suggested the Commission rewrite its policies and each pipeline’s tariff to allow natural gas-fired generators to “bump” firm shippers during periods of high demand. This approach will not address electric grid reliability concerns for at least four reasons. At the same time such approach would throw the systematic reservation and delivery of reserved capacity and gas supplies into chaos.First, the Natural Gas Act and the Commission’s longstanding orders regarding open access prohibit discrimination on the basis of end use. The Commission recognized in its Order No. 436 that “permitting pipelines to unduly discriminate or to exclude certain consumers from transportation services is inconsistent with the fundamental goals of consumer protection and competition in the Natural Gas Act and the Natural Gas Policy Act.” The Commission made “[n]on-discriminatory access” a “cornerstone” of Order No. 436 because open access “assur[es] that the benefits of competitively priced gas supplies and transmission services are being made available to the broadest number of consumers” and “helps to achieve a traditional utility ratemaking goal of maximizing throughput in order to spread fixed costs over the greatest number of customers.” The Order “prohibits discrimination among customer classes as well as on the basis of . . . the end-use to which the gas is put.” The Commission, through Order No. 636 likewise promoted open access because it was “vital to give all gas purchasers (LDCs and end users, such as industrials and gas-fired electric generators) the ability to make market-driven choices about the price of gas as a commodity and about the cost of delivering the gas.” These sound precedents have resulted in a clear, robust, competitive market for interstate pipeline services, ensuring that capacity is allocated to the parties that value it the most.Second, this approach would produce unjust and unreasonable rates. Pipelines cannot expand to provide additional firm capacity only during periods of peak demand. They are not balloons. So, companies must design pipelines to meet their firm shippers’ peak demand, though that means capacity may be available for use by others at non-peak times. Firm shippers do not use all the capacity required to satisfy their peak demand all year round, but they nonetheless pay for that peak capacity to ensure that the capacity is there when needed. It would be eminently unjust and unreasonable to permit natural gas-fired generators a “free ride” by allowing them to simply take firm transportation for limited periods without paying to reserve firm transportation rights as all other firm shippers do.Third, by allowing natural gas-fired generators to bump firm shippers without paying for firm transportation themselves, the value of firm transportation rights will decrease and, perversely, it will become more difficult to build the very natural gas infrastructure that is needed to address existing electric reliability problems. As explained in response to Question 1, the Commission will only authorize the construction or modification of natural gas pipeline facilities if the company can demonstrate “need” for the project, and the Commission historically has found “need” based on long-term precedent agreements for capacity. Entities will be less likely to execute those agreements if their firm transportation rights could be appropriated by generators during periods of peak demand. Without those agreements, pipeline companies will have significant difficulty expanding natural gas pipeline infrastructure.Fourth, this approach would require the creation of a hierarchy of human needs. Creation of this hierarchy implicates major questions of policy (e.g., Should the country prioritize electric generators over homeowners who rely on natural gas to heat their homes, their water, their food? Over facilities that manufacture medicine? Should electric generators that commandeer others’ natural gas transportation capacity or supplies pay for the re-lighting of a community’s natural gas services?[[9]](#footnote-9) Are the substantial—potentially catastrophic—losses at industrial facilities arising from a loss of natural gas more acceptable than temporary electric blackouts?). Neither NAESB nor the Commission are equipped to answer those questions. INGAA urges the participants in this forum to focus on electric market reforms rather than the creation of measures that disrupt the well-functioning nationwide market for natural gas delivery services resulting in foreseen and unforeseen confusion and chaos in the natural gas use market, and will not ultimately meet the objective of a reliable bulk power system. |
| 2 | LS Power Department | Mark Spencer | WEQ – Generator | We believe that there may be ways to incrementally increase gas availability through greater transparency/situational awareness. For example, if LDCs are procuring reserves that they do not need in real time, there may be a more efficient way to release the gas in a timely manner. We recommend that the states review their LDC policies and ensure that appropriate reserves exist, but the key is appropriate and not “too much.” As other commenters have noted, contractual terms have evolved to accommodate the needs of the electric industry. There is no perfect nomination time, and products and services have become more flexible. No doubt other products could be developed such as super short notice, but they would be extremely expensive. There is no point exploring other products and services without knowing the risk appetite and cost limits that state regulators have on behalf of their ratepayers. |
| 3 | The Process Gas Consumers Group (PGC) & the American Forest and Paper Association (AF&PA) | Andrea Chambers | WGQ – End User | Many industrials sign contracts for long-term firm pipeline transportation capacity. FERC tariffs require that all firm transportation customers must be curtailed pro-rata. Some of these customers sign firm gas purchase agreements. Since gas sales are not regulated, there is no basis for abrogating these private contracts or confiscating gas owned by private entities. The practical effect of the proposed assignment of “priorities” during constrained periods is that pipeline capacity and natural gas supplies would effectively be taken away from the shippers who are paying for that capacity and gas supply without compensation, which would constitute interference with their private contracts as well as jeopardize the safety of their workers and equipment. This prioritization would also ignore the fact that industrials have planned ahead and made arrangements for their energy needs. A more sound and fair approach would be to allow for voluntary offers to reduce demand with compensation for those industrials and other end-users who can reduce demand in the short-term and, in the long-term, planning for and building capacity where needed for a longer-term solution. |
| 4 | Texas Competitive Power Advocates (TCPA) | Michele Richmond | WEQ – Generator | Intrastate pipeline contracts are typically individually negotiated rate contracts; therefore, there are no standard published tariff rates and no requirement to separate pipeline operations from the pipeline’s marketing function or affiliate. Pipelines are free to charge unreasonable rates and operating fees (balancing services, OFO fees etc.) and restrict shippers’ access to third-party producers/suppliers and storage operators by denying access to critical receipt and delivery points, even though these points may be “in-path” to their primary receipt and delivery points.Onerous OFO fees or imbalance penalties charged by intrastate pipelines to non-offending power generators are unfair and result in higher costs for electric customers, while allowing intrastate pipelines to collect windfall profits. During winter storm Uri, power generators that were “long” gas supply were still charged balancing fees, even though the pipeline overall was “short” gas supply. In these instances, generators were helping the pipeline maintain supply reliability and operational integrity, and yet they were still unfairly penalized. The lack of market transparency hinders power generators from negotiating fair and reasonable contracts. The opaque structure makes it difficult for willing buyers and sellers to contract directly with each other and effectively restricts competition. Intrastate pipelines must post operational data on EBBs in order to help remedy this situation.The lack of a well-functioning capacity release market on intrastate pipelines hinders a power generator’s ability to economically manage firm transportation and storage contracts, especially for power generators that have low utilization (Peaking Units). Lack of a capacity release market also discourages marketing companies from participating in the intrastate market. This results in the pipeline marketing affiliate being the supplier of last resort, with the ability to exert market power.Lack of regulation surrounding pricing and market rules is exacerbated by the fact that most states do not have a functional complaint process; therefore, disputes between shippers and pipelines are typically pushed to the courts for resolution. Resolutions can take years and millions of dollars to resolve. Without separation of pipeline operational and marketing functions, pipeline marketing groups or affiliates have a distinct advantage that effectively limits third-party marketer participation in a delivered supply market.  |
| 5 | SoCalGas | Jonathan Peress | WGQ – Distributor | The following is focused on experience with gas/electric market interaction in California: The gas market is set-up as a ratable daily market whereas the electricity is monitored and priced at a more granular level. (5-minute increment in CAISO). The timing of these two dependent markets need to be more closely synchronized to better manage capacity issues. This dependency is already forcing gas operations to try and optimize its supply and infrastructure on an hourly (or even more granular basis), but without a gas market that sets prices, facilitates transactions and provides information in hourly increments, gas operators are somewhat limited in the information available and thus in their abilities to manage their systems. More granularity in price formation and transparency (e,g,, hourly) in the gas day would allow coordination across LDCs and pipelines, allowing each to economically and efficiently benefit from each other.Other participants have indicated that this type of change would largely be ignored by the gas market. While this may be true today and in some areas of the country, there are states like California that would benefit from such enhancement. Additionally, making this capability available now will prevent future issues for states that are at the earlier stages of decarbonization. Adding further temporal granularity will allow better pricing of beneficial attributes such as ramping and flexible storage. |
| 6 | PJM, MISO, SPP & NYISO | Joshua Phillips | WEQ - Independent Grid Operator & Planner | Reliability upgrades on the electric side are assigned on a ‘beneficiary pays’ approach. Within several ISOs and RTOs, the cost allocation matter has been settled with reliability upgrades above a certain voltage level being socialized RTO-wide with reliability upgrades at lower voltage levels being assigned based on flows on the system. Similar models could be explored for the pipeline industry through analyzing existing FERC precedents on the electric side and the degree to which they may be transferable to the gas side. However, this question is a regulatory question. |

| **Responses Submitted for November 8, 2022 Meeting – Question 6** |
| --- |
| **Question 6** | Ideally, what modifications to the existing processes for nominating firm service on interstate/intrastate pipelines would be the most beneficial in preparation for and during events when demand for natural gas is rising sharply and leading to constraints/unanticipated demand (i.e. operations on holidays/weekends, operations outside of the day ahead market)? |
| **#** | **Organization** | **Representative** | **Market/Segment** | **Comment & Specific Recommendation** |
| 1 | Interstate Natural Gas Association of America (INGAA) | Christopher Smith | WGQ – Pipeline  | Market dispatch clearing times are too late in the morning to provide generators time to purchase natural gas during periods of peak liquidity. Generators typically receive dispatch instructions after most of the natural gas is sold. Uncertainty regarding whether the ISO/RTO will dispatch them deters most generators from advance purchases of natural gas during tighter market conditions—when the gas is most needed. It is important that the ISO/RTO issues day-ahead awards in advance of the pipelines’ Timely Cycle and during the period that the gas commodity is most liquid. This would 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. As well, the ISO/RTO’s understanding of the generators’ portfolios of supply assets would be a key factor to assist in this planning process to assure that during peak periods the generators with the most firm supply are scheduled to run.Regardless of the timing of day-ahead awards, the current market structure does not incent gas generators to hold firm transportation rights, making them lower priority within the pipeline’s tariff and at risk of being unable to transport needed gas. This is particularly troublesome in areas of the country with insufficient pipeline capacity during periods of high demand. Earlier day-ahead awards to natural gas-fired generators might enable generators to nominate during the Timely Cycle and acquire natural gas at the most reasonable prices, but this does not create capacity on the pipeline. During such high demand periods, if the generator is relying only on interruptible transportation, early notice will not matter as that transportation will not be scheduled (even if it nominates every hour of the day) since higher priority firm shippers will be utilizing their own capacity. Efforts must be made to enable generators to recover the cost of firm transportation service (if available) and to reform the permitting process to remove obstacles to the expansion of natural gas infrastructure to facilitate appropriate pipeline capacity. |
| 2 | Natural Gas Supply Association | Pat Jagtiani | WGQ – Producer  | The ability to procure pipeline capacity and natural gas supplies after the Timely Cycle and on weekends is possible but creating a market for gas purchases during those times is predicated on a number of factors such as sufficient market engagement, price signals that induce gas sellers to reserve supplies for later purchases and the availability of physical assets capable of providing for unplanned flows. The natural gas industry must plan ahead for the bulk of its daily flows, but gas sellers will do all they can, primarily pulling gas from storage or redirecting supply when possible, during these times to accommodate unanticipated requests. Managing after hours or weekend requests can be especially difficult to fulfill in capacity constrained areas in which all available capacity is scheduled during the Timely Cycle. Also, as several have suggested during this forum, generators may want to seek out advance exchange agreements with other customers, such as industrials, that voluntarily agree to reduce their usage and transfer their contractual entitlements to a generator in close proximity. If it is determined that any of these types of exchanges require waivers from FERC, the forum recommendations should include consideration of blanket waivers for such transactions. Capacity release rules already allow for limited exceptions for short-term releases between two parties. Additionally, it would be helpful in this forum to further explore transparency, flexibility, and scheduling on intrastate pipelines and whether these issues are limited by region or by scope due to the unprecedented circumstances experienced during Winter Storm Uri. |
| 3 | The Process Gas Consumers Group (PGC) & the American Forest and Paper Association (AF&PA) | Andrea Chambers | WGQ – End User | We do not believe changes to the natural gas transportation nomination process are needed. Rather, the problem appears to be lack of transportation being built to serve electric demand. It is not possible to nominate pipeline capacity that does not exist. As to the availability of natural gas supply, it is possible to purchase gas on the weekends in our experience. The problem seems to be that the generators are not being dispatched at the times when the natural gas markets are most liquid and least expensive.  |
| 4 | Southern California Generation Coalition (SCGC) | Norman Pedersen | RMQ – Retail Electric Utility | The NAESB Business Practices permit gas supply nominations, confirmations, and scheduling on weekends and holidays. However, the North American gas commodity market does not provide a liquid gas market on weekends and holidays. SCGC supports reforming the North American gas commodity market so that the weekend and holiday gas commodity market would be as liquid as the weekday market. Interstate pipeline and intrastate pipeline capacity release markets should also be 24/7 markets. |
| 5 | PJM, MISO, SPP & NYISO | Joshua Phillips | WEQ - Independent Grid Operator & Planner | Modifications to the processes for nominating firm service should be to create a more flexible, liquid market for natural gas that trades closer to real time when forecasts are most accurate and system conditions don’t vary as widely. As noted during the 2021 winter storm, access to gas markets required nominating service for four days, creating an illiquid market as weather impacts became more certain. Additionally, it would be helpful to discuss the potential for offering of a premium capacity reservation product to accommodate for daily peak winter periods (morning and evening ramps). Such a product could be attractive to smaller combustion turbines which are typically called on in real time when needed for unanticipated demand increases. |



*Filed Via Email (naesb@naesb.org)*

November 4, 2022

North American Energy Standards Board 1415 Louisiana Street, Suite 3460

Houston, Texas 77002

**RE: AGA Comments in Advance of the November 8 Gas-Electric Harmonization**

**Forum Meeting**

North American Energy Standards Board:

The American Gas Association (“AGA”) appreciates the opportunity to comment in advance of the North American Energy Standards Board (“NAESB”) Gas-Electric Harmonization Forum’s (“GEH Forum”) November 8, 2022 meeting.

**I. Introduction**

AGA, founded in 1918, represents more than 200 local energy companies that deliver clean natural gas throughout the United States. There are more than 77 million residential, commercial and industrial natural gas customers in the U.S., of which 95 percent – more than 73 million customers – receive their gas from AGA members. AGA is an advocate for natural gas utility companies and their customers and provides a broad range of programs and services for member natural gas pipelines, marketers, gatherers, international natural gas companies, and industry associates. Today, natural gas meets more than one-third of the United States’ energy needs. AGA is an active member of NAESB and has participated in the various gas-electric coordination and harmonization efforts at NAESB and in other forums.

**II. Comments**

AGA thanks NAESB staff and the co-chairs of the GEH Forum for organizing the meetings and all their efforts so far. AGA provides these comments in response to some of the issues raised at recent GEH Forum meetings and noted in the questions issued by NAESB for the November 8 meeting. AGA is concerned about the limited time that has been provided so far to develop comments. AGA appreciates the fact that the Federal Energy Regulatory Commission (“FERC”) and the North American Electric Reliability Corporation (“NERC”) requested that NAESB convene this forum and that the FERC/NERC Report on the February 2021 Cold Weather Outages

**Matthew J. Agen,** Assistant General Counsel, Office of General Counsel

400 N. Capitol St. NW 4th Floor, Washington, DC, 20001 **P** 202-824-7090 **F** 202-824-9144 **E** magen@aga.org [**www.aga.org**](http://www.aga.org/)

in Texas and the South Central United States (“Winter Storm Uri Report”) included certain timelines; however, more time is needed to fully consider and respond to the issues raised in the survey questions and at the meetings. The Winter Storm Uri Report put a timeline of “Winter 2022-2023” for Recommendation 7. At this point, no recommendations coming out of the GEH Forum will be in place for this winter. Therefore, it is appropriate to recognize this and provide additional time for fully developed stakeholder comments. Looking forward, AGA respectfully requests that NAESB add more time to the comment periods.

Regarding the barriers to constructing and placing infrastructure into services, there are two broad categories of issues: incentivizing investment and receiving the required approvals. One of the themes discuss during the recent GEH Forum meetings is a lack of incentives or mechanisms to ensure generator fuel supply, which would include, among other things contracts for pipeline capacity, storage, and/or LNG. Related to the lack of incentives, is an absence of how to determine who would pay for new natural gas infrastructure to serve wholesale electric needs. It is critical that issues related to incentives and cost issues be vetted as part of the GEH Forum process. One of the overarching issues appears to be reliance on interruptible or non-firm pipeline capacity to meet the fuel requirements. Serious consideration should be given to how to value firm pipeline capacity, storage, and LNG, *etc*., as a way to ensure reliability. The cost of these facilities that provide reliability should somehow be factored into the electric markets. Notably, up to this point, other shippers have been relying on the capabilities in the upstream systems that have largely been paid for by the utilities and their customers.

Concerning the approval process, matters related to the permitting and construction of interstate facilities are heavily dependent on FERC, applicable state agencies, and the courts. Related to FERC, AGA has filed extensive comments at FERC in *Certification of New Interstate Natural Gas Facilities*, Docket Nos. PL18-1-000, *et al.*, and *Consideration of Greenhouse Gas Emissions in Natural Gas Infrastructure Project Reviews*, Docket Nos. PL21-3-000, *et al*.

* AGA’s July 25, 2018 Comments;1
* AGA’s May 26, 2021 Supplemental Comments;2
* AGA’s April 25, 2022 Comments;3
* AGA’s May 25, 2022 Reply Comments;4
* AGA’s March 18, 2022 Request for Rehearing and Clarification.5

Specifically, in these aforementioned submissions, AGA expressed its support for a streamlining of FERC’s certificate review process in order to provide for a timelier review of, and decisions on, infrastructure applications. In short, FERC should revise its policies to better streamline the review process. Natural gas companies face serious challenges in managing multiple overlapping, inconsistent, and often duplicative federal, state and local permitting processes. All too often, an inefficient permitting process results in considerable delays, increased costs for shippers, or worst of all, the demise of needed projects. Moreover, delays can leave stakeholders in limbo as to the status of a project that could have business, supply chain, or property implications. In an effort to avoid such situations, FERC should articulate, as part of

1 Available at https://elibrary.ferc.gov/eLibrary/filelist?accession\_number=20180725-5216.

2 Available at https://elibrary.ferc.gov/eLibrary/filelist?accession\_number=20210526-5200&optimized=false.

3 Available at https://elibrary.ferc.gov/eLibrary/filelist?accession\_number=20220425-5487&optimized=false.

4 Available at https://elibrary.ferc.gov/eLibrary/filelist?accession\_number=20220525-5190&optimized=false.

5 Available at https://elibrary.ferc.gov/eLibrary/filelist?accession\_number=20220318-5215&optimized=false.

any forthcoming policies, what it expects from the various federal, state and local authorities that are involved in FERC-jurisdictional projects and the appropriate timelines for action on matters.

AGA is concerned that an untimely review may undermine the resilience of the gas system. This is especially concerning due to the fact that hundreds of millions of Americans rely on the gas system either directly or indirectly. Our nation’s energy system is transforming, driven by changes in cost, the availability of new technologies, and the increasing political and social pressure to decarbonize. This transformation has brought to light an issue of energy system resilience related to the growing interdependency of the gas and electric systems and the importance of an efficient pipeline application review process.

Regarding planning and forecasting for customer needs, based on the discussion during the recent meetings, there appears to be a need for some to update planning and forecasting processes due to the fact that interruptible or non-firm pipeline capacity to serve unanticipated demand is becoming more and more scarce. Updated planning and forecasting may address some issues. However, if it does not, consideration should be given to obtaining sufficient firm pipeline capacity or other services needed to meet forecasted demand and for reliability purposes.

AGA provided a high-level overview of the natural gas utility planning process, in its September 14, 2022 letter to NAESB. AGA is also willing to provide more detail regarding planning in an educational session of the GEH Forum. In short, due to the obligation to serve, natural gas utilities develop detailed long-term supply and transportation plans to ensure that they can reliably meet the physical demand for service on peak days both today and in the future. Acquiring and maintaining pipeline capacity and natural gas supply is an integral part of this planning process. Natural gas utilities rely on the contractual agreements with pipelines and FERC approved tariffs, and provide service under state approved tariffs. The contract terms and tariffs are not barriers to receiving service, on the contrary, such items are essential to receiving reliable service.

The premise of the concern raised in a recent survey question appears to assume that when there is constrained capacity or unanticipated demand, contract terms and FERC or state approved tariff provisions should be superseded for the benefit of a select group of shippers. The question should be how can those that need natural gas be incentivized to secure needed supply, including upstream pipeline capacity, so that reliability can be maintained when there are times of constrained capacity or unanticipated demand. In short, how can those that have a need for reliable service avail themselves of the benefits of the contractual agreements and FERC/state approved tariffs that provide the requisite fuel assurance. AGA recommends that generators work with pipelines and gas utilities that serve generators to come up with services that the generators desire, with the goal of achieving the best utilization of the existing contracting and regulatory process.6

During the recent meetings and in the recently issued questions, concepts regarding changes to both the gas and electric market scheduling processes have been raised. Before seeking to modify existing natural gas processes, consideration should be given to how the electric markets may need to be updated to reflect the changing generation fuel mix. Modifying

6AGA acknowledges that in some jurisdictions there may be legislative or regulatory hurdles for generators contracting for pipeline capacity; however, the broader conversion about fuel assurance needs to take place.

scheduling deadlines on the gas system will not necessarily create additional upstream pipeline capacity that can be used to meet those entities’ “unanticipated demand.” There is a finite amount of pipeline capacity available and those entities that are paying the pipelines the fixed charges for the right to utilize that finite amount of pipeline capacity on a firm basis should remain in control of that capacity. This capacity should remain available to firm shippers to meet their demands based on the current pipeline scheduling deadline and rules. Changes to scheduling deadlines and rules will penalize those entities that pay the fixed firm pipeline charges, have properly forecasted their demands, and have sufficient upstream pipeline resources to meet their forecasted demands.

Regarding the current process and any forthcoming changes to the gas or electric markets, any impacts would need to be fully vetted. For example, the current process has an impact on gas utilities with behind-the-city-gate generation, both in how the systems are managed and on costs. It is AGA’s general understanding that gas-fired power generators that operate within an ISO/RTO may not know if or when they will need to run in time to secure pipeline transportation capacity and supply. If the generator holds off on obtaining supply and capacity that creates one set of issues such as a lack of capacity or increased costs. If a generator behind the city gate is in this situation the utility works with the customer to resolve the issue. However, the reality is that this situation may illustrate a need for more physical assets that provide operating flexibility, including no-notice resources that can be used to balance the system.

On the other hand, if a generator acquires supply and capacity in advance only to not receive the order to run that creates a separate set of issues. When this happens generators that operate behind the city-gate reduce their nominations because the generator does not need to operate. This then results in the utility being out of balance since it planned on the supply showing up at the city-gate. This requires that the utility have no-notice services (on or off-system assets) to keep the utility system balanced. In other words, because of the way the electric markets are structured, utilities may need to maintain various types of contracts to ensure system operations. The costs for maintaining the system should be borne by those that cause the imbalance. AGA believes that the efforts utilities undertake to maintain the system should be recognized by the GEH Forum. Moreover, the impacts of the current scheduling process should be fully understood before changes are proposed.

**III. Conclusion**

The American Gas Association respectfully requests that NAESB consider these

comments.

Respectfully submitted,

Matthew J. Agen

Assistant General Counsel American Gas Association

400 N. Capitol Street, NW Washington, DC 20001

202-824 7090

magen@aga.org

November 4, 2022

1. NERC Report, State of Reliability, July 2022, <https://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/NERC_SOR_2022.pdf> [↑](#footnote-ref-1)
2. “U.S. Companies on Pace to Bring Home Record Number of Overseas Jobs,” The Wall Street Journal, August 20, 2022, <https://www.wsj.com/articles/u-s-companies-on-pace-to-bring-home-record-number-of-overseas-jobs-11660968061> [↑](#footnote-ref-2)
3. U.S. Government Accountability Office, September 2020: Gas Transmission Pipelines; <https://www.gao.gov/products/gao-20-658#summary_recommend> [↑](#footnote-ref-3)
4. U.S. Government Accountability Office, September 2020: Gas Transmission Pipelines [↑](#footnote-ref-4)
5. IECA: EIA Explains Why U.S. Manufacturing Cannot Switch from Natural Gas to Electricity, <https://www.ieca-us.com/wp-content/uploads/07.15.21_MECS-Fuel-Switching-IECA-Statement.pdf> [↑](#footnote-ref-5)
6. “Duke Energy plans to exit all coal, double renewables,” Kristi E. Swartz, E&E News Energywire, <https://www.eenews.net/articles/duke-energy-plans-to-exit-all-coal-double-renewables/> [↑](#footnote-ref-6)
7. Mike Knowland, Manager, Operations Forecast and Scheduling, ISO-NE, New England Winter Gas-Electric Forum Panel 2: Concerns for Winter 2022/23 and Future Winters at 13-14, New England Winter Gas-Electric Forum, Docket No. AD22-9 (Sept. 2, 2022); Robert Walton, ‘Batteries aren’t going to do it’: NERC’s Moura calls for gas investment to maintain reliability, Utility Dive (July 21, 2022), <https://tinyurl.com/3dj5e33d>. [↑](#footnote-ref-7)
8. NATURAL GAS SYSTEMS: RELIABLE & RESILIENT, NATURAL GAS COUNCIL (2017), <https://tinyurl.com/442ayc6a>; Energy Information Administration, California fuel mix changes in response to September heat wave (Sept. 21, 2022), <https://tinyurl.com/u5a6jzrh> (“CAISO predominately used natural gas, electricity imports, and hydroelectric sources during the highest demand hours to meet the record-breaking demand, which was a change from the typical mix. . . . CAISO used natural gas for as much as 60%—and never less than 30%—of the generation mix to meet electricity demand.”); NERC, February 2021 Cold Weather Grid operations: Preliminary Findings and Recommendations at 15 (During Winter Storm Uri, “natural gas pipelines were only minimally affected by power outages (because most have backup power) and were largely able to meet their firm transportation commitments.”). [↑](#footnote-ref-8)
9. To recover from a natural gas service outage is not as immediate as simply restoring the flow of electricity in the transmission or distribution grid. Often, local distribution company personnel must access customer premises to ensure that natural gas-fired appliances and meters are turned off and locked, prior to re-introduction of natural gas to distribution networks; technicians are dispatched to turn on gas meters and safely re-light customer appliances. See, e.g., <https://www.nationalgridus.com/media/pdfs/storms-outages/2021-gas-restoration-process.pdf>. [↑](#footnote-ref-9)