

**STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES**

In the Matter of Natural Gas Commodity and Delivery Capacities in the State of New Jersey – Investigation of the Current and Mid-Term Future Supply and Demand	BPU Docket No. GO20010033
In the Matter of the Exploration of Gas Capacity and Related Issues	BPU Docket No. GO19070846

**COMMENTS OF ENVIRONMENTAL DEFENSE FUND, NEW JERSEY
CONSERVATION FOUNDATION, AND COLUMBIA LAW SCHOOL’S
SABIN CENTER FOR CLIMATE CHANGE LAW**

We commend the New Jersey Board of Public Utilities (“BPU”) for undertaking a data-driven approach to assessing New Jersey’s available gas capacity, and offer the following comments and recommendations to support BPU’s essential next steps. The London Economics International Study (“LEI Study”) demonstrates that New Jersey gas distribution companies (“GDCs”) have sufficient gas supply out to 2030 to meet system demand, without adding pipeline capacity to their supply portfolios. The findings of the LEI Study demonstrate the risks of continuing to operate under a business-as-usual paradigm, and the need for an orderly and transparent planning process to avoid unnecessary gas infrastructure buildout and ensure alignment with New Jersey climate policy. For example, the LEI Study creates transparency around the assumptions GDCs rely on to determine gas demand, and demonstrates that GDCs overestimate demand. The BPU should exercise its authority and statutory mandate to regulate the GDCs to ensure that they are planning in accord with the decreased reliance on gas necessary

to achieve the GHG emission reductions required under New Jersey law.¹ Doing so will protect ratepayers, public health, and ensure that the BPU's oversight of utilities is aligned with New Jersey climate change and environmental justice policies, including protecting vulnerable populations from the worst impacts of climate change. The BPU should operationalize several of the LEI Study's crucial findings by commencing a Gas Planning Docket² designed to support the following actions:

- (1) requiring GDCs to seek BPU's approval prior to signing Firm Transportation contracts for gas capacity when those contracts are for five year terms or greater to demonstrate cost effectiveness and genuine need;
- (2) creating a planning process that GDCs must follow, to be revisited on a biennial basis, containing a portfolio of NPAs and ranking of resources and system operations that will protect against gas supply shortfalls, including those resulting from outage, that could arise by 2030, however unlikely those scenarios may be;
- (3) defining a design day that is predicated on objective, measurable, and transparent weather conditions;
- (4) providing for stakeholder participation by assuring that the presumptions, data and analyses upon which the GDCs are relying in their planning analyses and prior approval requests are transparent and accessible to stakeholders, who can participate in the process as full parties.

Our comments will examine each of these important aspects of gas planning, and we believe that the best outcome could be achieved by addressing them together in a holistic proceeding, which

¹ See N.J. DEP, New Jersey's Global Warming Response Act 80x50 Report at xi (Oct. 2020), <https://www.nj.gov/dep/climatechange/docs/nj-gwra-80x50-report-2020.pdf> ("The least cost scenario modeling performed for the 2019 EMP calculated that 90% of buildings must be converted to 100% clean energy systems to meet the 2050 emission goals.").

² EDF and NJCF previously submitted detailed comments to BPU describing the importance of invoking a gas planning docket, as well as providing a list of critical components for this docket to be successful. See Exhibit A, Comments of The Environmental Defense Fund and New Jersey Conservation Foundation, BPU Docket Nos. GO20010033, GO19070846 (May 18, 2021). We attach those comments as Exhibit A to this filing, so that the Board may easily contextualize them as they relate to the LEI Study findings, as well as our additional comments herein.

would flow from, and connect to, individual GDC-specific proceedings. As the LEI Study noted, other jurisdictions have commenced similar proceedings to ensure that ratepayers are protected through planning for energy transitions, and that the states' clean energy laws can be met in the least cost fashion.³ By engaging LEI, BPU has taken a critically important first step to determine that there is sufficient existing capacity for GDCs until at least 2030. By using these data and analyses to support robust gas planning, BPU will protect ratepayers, ensure reliability, and keep its utilities on track as the state decarbonizes buildings, transportation, and energy.

I. The LEI Study contains important findings that should inform BPU oversight of GDCs

The LEI Study provides a valuable overview of available gas supply in New Jersey and constructively identifies concerns with the method of demand forecasting employed by New Jersey GDCs. The LEI Study also critiques the Affidavit of Gregory Lander, Skipping Stone

³ See LEI Study at 62-3 (describing the New York gas planning docket). See also *Investigation by the Department of Public Utilities on its own Motion into the role of gas local distribution companies as the Commonwealth achieves its target 2050 climate goals*, Mass. D.P.U. 20-80, Vote and Order Opening Investigation at 7 (October 29, 2020) (Massachusetts gas planning docket); *Order Instituting Rulemaking to Establish Policies, Processes, and Rules to Ensure Safe and Reliable Gas Systems in California, and Perform Long-Term Gas System Planning*, CPUC Rulemaking 20-01-007 (January 27, 2020) (California gas planning proceeding); *General Investigation into Retail Natural Gas Industry Greenhouse Gas Emissions in Light of Statewide Emission Reduction Goals Adopted in House Bill 19-1261*, Colorado PUC proceeding 20M-0439G (October 29, 2020) (Colorado gas planning proceeding); *Order No. 38189 Instituting a Proceeding to Investigate Integrated Resource Planning For Hawaii Gas*, Hawaii PUC (January 19, 2022) (including directive to “address and further State policies including emissions reductions and decarbonization goals”); D.C. PSC Order No. 20754, F.C.1167, *In the Matter of the Implementation of Electric and Natural Gas Climate Change Proposals* (June 4, 2021) (directing each utility to file detailed climate plans and analyses and establishing stakeholder engagement opportunities); D.C. PSC Order No. 20662, F.C.1167, *In the Matter of the Implementation of Electric and Natural Gas Climate Change Proposals* (Nov. 18, 2020) (opening a new climate proceeding to determine utility consistency with D.C. energy and climate goals).

LLC (Oct. 2019) (on behalf of EDF and NJCF), and a response to those critiques is provided in the attached statement of Gregory Lander, Skipping Stone LLC.

Foremost, the LEI Study correctly demonstrates that New Jersey GDCs have sufficient gas supply out to 2030 to meet system demand without adding pipeline capacity to their supply portfolios, and a shortfall would occur only in the event of an unlikely, extreme outage or demand episode.⁴ The LEI Study demonstrates that New Jersey GDCs have been overestimating demand by using the wrong baseline data⁵ -- which would necessarily yield uneconomic outcomes tied to inaccurate planning. LEI develops its own demand estimates that depart from GDC projections in multiple important ways, including by rejecting the assumption made by two GDCs that “efficiency will not improve in the future relative to the past,” and by declining to rely on assumptions that customers will switch from oil to natural gas.⁶ And crucially, LEI developed demand scenarios that account for “New Jersey clean energy programs going forward.”⁷ To avoid overbuilding gas infrastructure, it is essential that GDC planning accounts for clean energy policies that may drive reductions in gas demand. The LEI Study concludes that, without accounting for efficiency program achievements, the demand outlook is 0.95% per year -- lower than the GDCs’ estimated 1.02% compounded annual growth rate (CAGR) for total design day firm demand from 2020 to 2030.⁸

⁴ See LEI Study at 15.

⁵ For example, LEI’s analysis shows that the GDCs’ 1.02% CAGR for total design day firm demand from 2020 to 2030 is too high, for several reasons. See LEI Study at 11. As set out below, there are significant consequences to such an inaccuracy, because system needs are designed based on the design day; errors like this one would have led to system overbuild.

⁶ See LEI Study at 11.

⁷ *Id.*

⁸ *Id.*

The LEI Study provides important critiques of the Levitan Report, which are also relevant to the approach used by New Jersey GDCs. The LEI Study explains that the Levitan Report took the GDC demand projections at face value, and thus overestimated demand.⁹ Furthermore, LEI observes that the Levitan Report failed to consider non-pipes alternatives and instead assumed that “the only way to address a shortfall in firm supply is by expanding pipeline capacity.”¹⁰ The LEI Study states that although there are “a number of potential solutions” to address supply shortfalls, the “subtext” of the Levitan Report “is that there is only one solution: more pipeline capacity.”¹¹

Such analysis, structured to reach a single conclusion that more pipeline capacity is needed, is not credible. BPU must ensure that long-term contracts and other GDC plans to expand gas supply and distribution are carefully reviewed, and the recommendations provided herein detail an appropriate process. The LEI Study recommends that BPU should “[d]evelop rules, as they are more reliable than recommendations” to cope with extreme weather or other emergency scenarios that could disrupt supply. LEI recommends that BPU develop “enforceable rules . . . for actions and processes which can prevent emergencies,” and that BPU should deploy available strategies under its control.¹² Requiring long-term supply planning by all GDCs, consistent with New Jersey climate law, is an essential step that BPU must take, and it is aligned with the LEI Study’s recommended best practices to prevent emergencies. The LEI Study

⁹ LEI Study at 15.

¹⁰ LEI Study at 15.

¹¹ LEI Study at 85.

¹² LEI Study at 17.

correctly states that developing enforceable rules “require stakeholder consultation and input”¹³ – BPU should act accordingly by ensuring a transparent, public planning process for GDCs.

II. The BPU should require that GDCs seek approval prior to executing long-term (5 years or greater) contracts for firm transportation and/or other firm pipeline-related supply options.

As the LEI Study makes clear, without accurate data and analyses, it is difficult (if not impossible) to accurately assess reliability needs, which may lead to overbuilding at New Jersey ratepayers’ expense. Project developers frequently propose new pipeline capacity, whether intrastate or interstate, relying on vague justifications of system reliability, cost benefits, or supply diversity. Currently, GDCs execute precedent agreements for firm transportation capacity with interstate pipelines without any advance BPU oversight or prior approval. Because these contracts are used to support building new capacity, they can be directly responsible for driving system overbuild if not weighed with the appropriate regulatory scrutiny. To align with state laws, BPU can and should require GDCs to seek prior approval for long-term firm contracts, so that it can direct GDCs to obtain sufficient capacity to meet all firm customer needs “in a manner that tends to conserve and preserve the quality of the environment.”¹⁴

To achieve this statutory mandate, the BPU should require GDCs to: (1) clearly articulate the project need and disclose all data and analyses, including baselines and assumptions, relied upon; (2) address how the proposed new capacity (or capacity-related) contract would or would not wholly address reliability objectives; (3) if the proposal is based on an outage scenario, provide Tariff provisions that support assertions of reduced impact of outage; (4) if a capacity constraint is identified, assess the most cost effective and environmentally beneficial solution by

¹³ LEI Study at 17.

¹⁴ N.J.S.A. § 48:2-23.

using a transparent and competitive request for proposal (“RFP”) process;¹⁵ (5) demonstrate why NPA alternatives, both demand-side and supply-side could not address the project purpose; and (6) assess the GHG emissions impacts from the proposed additional capacity as well as the GHG emissions impacts from alternatives that could meet project purpose.

A. Past Interstate Pipeline Projects Indicate the Need for BPU to Implement a Process for Advance Approval

As the LEI Study confirms, the PennEast pipeline provides a salient example of why prior approval of long-term firm transportation on interstate projects is essential to protect against overbuilding.¹⁶ In the certificate proceeding before the Federal Energy Regulatory Commission (“FERC”), PennEast relied on long-term precedent agreements, including with GDCs, to assert that the proposed project was needed and should be approved.¹⁷ New Jersey Rate Counsel, NJCF, EDF and others presented data and analysis to FERC demonstrating that additional capacity was not needed, and that the proposed capacity would provide minimal benefits at a high cost to ratepayers. Ultimately, after an *enormous* investment of time, resources, and expertise, by the state as well as project opponents, the developers pulled the project.¹⁸ If the GDCs had needed prior approval from BPU to enter such long-term transportation contracts,

¹⁵ See Exhibit A, Comments of The Environmental Defense Fund and New Jersey Conservation Foundation, BPU Docket Nos. GO20010033, GO19070846 (May 18, 2021) at 19-22 (detailing RFP framework).

¹⁶ See LEI Study at 28-29 (explaining that all New Jersey GDCs had contracted for capacity on PennEast, and those precedent agreements were used in PennEast’s certificate application to FERC).

¹⁷ See Request For Rehearing And Motion For Stay on Behalf of New Jersey Conservation Foundation And Stony Brook-Millstone Watershed Association, FERC Docket No. CP15-558, Accession #20180213-5082, at 6-7.

¹⁸ *PennEast Pipeline Co., LLC*, 177 FERC ¶ 61,197 (December 16, 2021) (“PennEast informed the Commission that it determined the Project ‘is no longer supported’”).

BPU could have assessed whether the capacity was needed within an engaged and transparent stakeholder process. That oversight could have averted the years-long battle over the PennEast pipeline.

Now that BPU has taken the essential first step of assessing available capacity and determining that there is no shortfall out to 2030,¹⁹ it can and should require that New Jersey GDCs seek approval prior to signing long-term contracts for (or supporting) firm transportation on pipelines. This will provide much-needed transparency and the opportunity for BPU to determine what data and models it will require GDCs to provide to support stated project purpose and need for additional capacity. Absent this safeguard, there is a significant danger that prior to the finalization of the first gas supply planning process, GDCs will continue to pursue such contracts and BPU's only recourse will be to deny cost recovery for imprudent investments: a path that most parties agree fails to adequately protect ratepayers and flies in the face of the state's GHG emissions reduction goals.

B. Past Intrastate Projects Indicate the Need for BPU to Implement an Open, Reticulated, and Transparent Process for Advance Approval

Although the BPU currently has an opportunity to evaluate relevant factors such as demonstrated need prior to approving *intrastate* pipelines,²⁰ its existing process does not adhere

¹⁹ Indeed, the LEI study itself underestimates available capacity, at times conflating increased price with unavailability. See Verified Statement of Gregory Lander of Skipping Stone in Response to London Economics International Report, attached hereto as Exhibit C, at 2-5.

²⁰ See N.J.S.A. § 48:2-27. See, e.g., *In the Matter of the Petition of New Jersey Nat. Gas Co. for Approval & Authorization to Construct & Operate the S. Reliability Link Pursuant to N.J.A.C. 14:7-1.4*, No. GE15040402, 2015 WL 5013171, at *1 (Aug. 19, 2015) (N.J.A.C. 14:7-14 requires Board approval prior to the construction or operation of a natural gas pipeline that will operate in excess of 250 psig and is located within 100 feet of any building intended for human occupancy)

to a clearly articulated set of principles or proceed with due transparency and public participation. Thus, the existing process can result in uneconomic and environmentally damaging outcomes and requires updating.

New Jersey Natural Gas' Southern Reliability Link ("SRL") project demonstrates that despite the BPU's opportunity to weigh whether new intrastate pipelines are necessary to ensure sufficient supply capacity, absent an open stakeholder process and the kind of gas planning procedures recommended in Parts II and III, it can still be difficult to assess reliability needs accurately and lead to overbuilding at ratepayer expense. NJNG proposed the SRL project to purportedly enhance system resiliency and address a single point of failure scenario.²¹ However, an expert analysis by Skipping Stone: (1) demonstrated that the SRL project was not an "efficacious, reasonable or cost-effective response" to that scenario; and (2) presented an alternative that would cost less than 20% of the proposed project with far less environmental harm.²² This analysis was not accepted as record evidence because BPU denied intervention to interested stakeholder groups, and BPU approved the SRL project although it did not effectively address the reliability issue it was designed to resolve, an issue that could have been addressed by a much smaller capacity expansion project at a fraction of the cost to ratepayers.²³

²¹ See *In the Matter of the Petition of New Jersey Nat. Gas Co. for A Determination Concerning the S. Reliability Link Pursuant to N.J.S.A. 40:55d-19 & N.J.S.A. 48:9-25.4*, No. GO15040403, 2016 WL 1159116 (Mar. 18, 2016).

²² See Exhibit B, *Analysis of the Southern Reliability Link as a Response to Single Point of Failure Concern* (Skipping Stone 2017) (showing that in a case of *complete* failure along the TETCO mainline, "NJNG would still be able to receive between 96% and 100% of its contracted supplies because of the high level of diversity and reliability that already exists in the TETCO supply system due to its bidirectional flow characteristics near the NJNG interconnect with TETCO.").

²³ See Part V *infra*.

The PSE&G Energy Strong II proposal to improve system reliability by building new intrastate gas pipeline capacity is another example of the need for an open and reticulated prior approval process and more transparent supply planning. The proposal relied on mistaken assumptions about availability to New Jersey of interstate pipeline capacity in the event of a major pipeline failure: PSE&G assumed that a failure of a portion of the Texas Eastern (TETCO) system in Pennsylvania would result in zero gas supplies reaching a portion of its network in New Jersey.²⁴ Despite limiting NJCF to participant status, NJCF shared significant critiques of the proposal, including that PSE&G, as well as other firm shippers, would receive 100% of supply necessary to meet their demands and therefore did not need additional pipeline infrastructure. Ultimately, BPU approved a settlement that denied PSE&G's proposed large investment in unnecessary gas infrastructure.²⁵ But this outcome is far from assured when the appropriate analysis is neither required as part of routine practice, nor part of an inclusive process. A more transparent gas planning process is needed to provide an opportunity for stakeholders to review utility assumptions and introduce external analysis that may challenge those assumptions.

New Jersey gas utilities will continue to propose new intrastate and interstate reliability projects, like SRL, Energy Strong II, and PennEast, which require BPU to create a newly structured advance review and approval process that ensures any approved projects are necessary

²⁴ See generally, *Verified Petition In the Matter of the Petition of Pub. Serv. Elec. & Gas Co. for Approval of the Second Energy Strong Program (Energy Strong II)*, NJBPU Docket No. EO18060629 (June 8, 2018), available at <https://publicaccess.bpu.state.nj.us/>.

²⁵ See *In the Matter of the Petition of Pub. Serv. Elec. & Gas Co. for Approval of the Second Energy Strong Program (Energy Strong II)*, No. EO18060629, 2019 WL 4694166 (Sept. 11, 2019) (authorizing \$50.5M in station upgrades but no additional pipelines, of \$863M proposed for curtailment resiliency, which included massive investments for additional pipelines).

and cost-effective. Ratepayers will benefit from a new process that brings additional scrutiny and analysis to such projects. Taken together, these prior experiences show why it is imperative that the BPU (1) set out clearly articulated criteria by which it will evaluate both interstate and intrastate project proposals, and (2) ensure that reviews of project proposals are considered in open, transparent, and accessible proceedings. Ensuring that such proceedings are open to interested stakeholders will help the BPU ensure that GDC testimony, data and analyses are vetted and tested for completion and accuracy.

Above, we provided specific questions BPU ought to require GDCs to answer in order to help inform its examination and evaluation of GDC proposals for building, taking or supporting long-term firm transportation capacity. Opening a gas supply planning docket to aggregate, standardize, and operationalize the prior approval process as a first step will give the GDCs visibility into what standards they must meet and which analyses they must undertake. It will result in a more efficient process for GDCs, stakeholders, and the BPU, and help pave a more economic and environmentally sustainable path forward.

III. BPU should create a robust gas supply planning process that GDCs must follow, which will protect against infrastructure overinvestment and ensure reliable supply.

The LEI Study findings raise a number of issues that can and should all be addressed in a gas supply planning docket designed to create a mandatory biennial GDC supply planning procedure. A robust process would help to address structural issues regarding transparency, accountability, and cost effectiveness identified by the report. LEI's data and analysis yielded the following significant findings: (1) GDCs were overestimating the compounded annual growth rate (CAGR) for total design day firm demand;²⁶ (2) demand side non-pipeline

²⁶See LEI Study at 11 (GDCs used unsupported, inflated baseline to project growth).

alternatives are more consistent with state laws and goals than supply-side alternatives;²⁷ (3) if even half of the Energy Master Plan IEP Least Cost target is met, it would address even the low likelihood 1 in 90 years winter demand condition;²⁸ (4) GDCs are not currently providing critical data about what drivers they rely upon in their forecasting models;²⁹ (5) while advanced leak detection (“ALD”) does not inherently represent a new/alternative source of natural gas supply, it ensures that no natural gas delivered into the system is wasted, and minimizes the occurrence of LAUF gas;³⁰ (6) integrating demand-side NPAs³¹ into gas planning not only ensures reliability and protects against shortfall, but also protects ratepayers from excessive costs from building new supply capacity.³²

Considering LEI’s findings as a whole, they make clear that when the BPU engages in a gas supply planning process, it should be integrated with a GHG emissions assessment that aligns with state law. State law GHG reduction mandates inform implementation of the following proposed prioritization framework that can present guiding principles for the BPU’s gas planning process as confirmed by LEI’s findings: (1) account for all combustion related GHG emissions

²⁷See LEI Study at 13 (There is an opportunity to meet state goals by selecting appropriate NPAs).

²⁸See LEI Study at 17 (NPAs can alleviate risk of supply shortfall when included in planning).

²⁹See LEI Study at 45 (noting lack of disclosure as a barrier to validating planning).

³⁰See LEI Study at 70, 78 (noting relationship between ALD and LAUF, and GHG reduction goals).

³¹ LEI considered the following demand-side NPAs: energy efficiency, demand response programs (time of use, direct load control), and targeted electrification. See LEI Study at 56-57. LEI additionally considered the following supply-side NPAs: renewable natural gas (locally produced or developed on-system), green hydrogen (on-system, within the constrained area), liquefied natural gas, and compressed natural gas, and advanced leak detection (ensuring no wasted supply). See LEI Study at 57. It found that demand-side NPAs were most consistent with state goals. See LEI Study at 12-13.

³² See Figure 51, LEI Study at 110 (at high levels of acceptance, NJ GDCs could have saved customers millions of dollars by offering thermostat rebates compared to the pass-through costs of new capacity on PennEast).

and fugitive methane emissions; (2) account for supply- and demand-side options to manage and meet gas demand; (3) use the most recent, publicly available data; (4) identify and incorporated significant uncertainties; (5) align the analysis with state GHG reduction targets reflected in the GWRA, Energy Master Plan, Clean Energy Act, and guiding Board orders.

While the LEI Study underrepresents available capacity,³³ it provides both a data driven and conceptual framework supporting the above-described integration of gas supply planning and GHG emissions reduction goals. And as LEI indicates, BPU has both the authority and responsibility to ensure that New Jersey’s GDCs maintain reliable supply *while* implementing required GHG emissions reductions -- but this will not happen without planning.³⁴ The process resulting from a BPU gas supply planning docket should be a biennial one, which requires GDCs to set out a portfolio of NPAs, specify an orders of operations that they will use to protect against gas supply shortfalls, including those resulting from outage,³⁵ that could arise by 2030, however unlikely those scenarios may be, and demonstrates consistency with state laws requiring GHG

³³These factors include, among other things, conflating availability with price, ignoring North-South and South-North paths through New Jersey with delivery points outside of New Jersey, and failure to contextualize the importance of considering interruptible users’ demand data. *See* Exhibit C at 2-5

³⁴ *See, e.g.*, LEI Study at 2 (“the ultimate usefulness of LEI’s Playbook depends on tools and procedures which New Jersey and the gas distribution companies (“GDCs”) should put in place ahead of time so that they are ready to be called upon as needed.”); LEI Study at 17-18 (New Jersey should “Develop rules,” “[f]ocus on strategies under the BPU’s control,” and “[b]egin now,” so that it will “have the capability to withstand even large natural gas supply shortfalls, [by]. . . planning ahead.”); LEI Study at 96 (“Assuming planning for support and implementation begins soon, a variety of NPAs can be combined to address this shortfall, without the need for direct load control. . . .”).

³⁵ As Exhibit B demonstrates, outage scenarios need to be critically assessed, with BPU giving GDCs guidance as to what outage scenarios they should consider in planning. Overly simplistic outage scenarios can lead to risk of overbuilding, as well as solutions proposed that do not correlate to or address the risks presented.

emissions reductions.³⁶ Commenters previously submitted a proposed design for such a gas supply planning docket, and reincorporate our proposal as Exhibit A.³⁷

IV. The BPU should employ objective and measurable criteria to establish a GDC's Design Day

At the moment, New Jersey's GDCs do not have a standard definition of design day or hour -- a critical measure that drives the system's buildout. Design day is a parameter that underpins GDCs' advance planning and analyses, and must be objectively and transparently defined to ensure appropriate planning.³⁸ And although BPU has the statutory authority to do so, it has not imposed any requirement that GDCs engage in long-term gas planning consistent with state clean energy goals.³⁹ During BPU's stakeholder meetings, GDCs commented that they

³⁶ Once this process is operational, the prior approval process can and should be integrated into it such that GDCs are putting out RFPs that reflect their required planning, targets and goals. For example, RFPs designed to meet a specific anticipated need should preference providing new supply capacity through NPAs or services for reducing demand.

³⁷ Additionally, other tools exist to assist BPU in formulating its gas planning proceeding. *See, e.g.,* Regulatory Assistance Project, Under Pressure: Gas Utility Regulation for a Time of Transition (May 2021), <https://www.raponline.org/wp-content/uploads/2021/05/rap-anderson-lebel-dupuy-under-pressure-gas-utility-regulation-time-transition-2021-may.pdf>.

³⁸ Our initial comments set out appropriate measures, as well as explaining why use of those standards, as well as all-in cost metrics, are critical. Exhibit A at 30 (recommending that the Board establish a 1 day in 30 year ("1-in-30") Design Day as the weather that drives the demand for which the GDCs plan. While the weighting of the temperature values from the weather stations in or proximate to each of New Jersey GDCs' service territories may vary, having the same 1-in-30 standard based on the same 1-in-30 day is recommended.); *id.* at 19 ("all-in cost metrics can serve as a valuable tool in elucidating the least cost option for customers and should be incorporated into an updated planning framework.").

³⁹ *See* N.J.S.A. § 48:2-23 (board authority to "require any public utility to furnish safe, adequate and proper service, including furnishing and performance of service in a manner that tends to conserve and preserve the quality of the environment and prevent the pollution of the waters, land and air of this State"); N.J.S.A. 48:3-87.9 (directing BPU to "require each electric public utility and gas public utility to reduce the use of electricity, or natural gas, as appropriate, within its territory," and consider peak demand reduction, energy efficiency, and other measures);

alone know their systems and should be responsible for planning and using metrics that can only be tailored to their individual territories. The problem with failing to specify metrics and approaches that inform GDCs planning is not only the complete lack of transparency, and therefore ability to test their assumptions, projections, and forecasts, but also that GDCs are failing to meet the statutory mandate of delivering safe and reliable service in a manner that protects the environment. Moreover, as set out in our initial comments, currently GDCs are not required to include long term gas planning information in any BGSS proceedings to inform and contextualize rate requests. BPU should produce an objective standard for design day and design hour, and standards and requirements for GDC long term gas planning. This can and should be done within a holistic gas planning docket, followed by individual GDC proceedings once the standard is set, which together will ensure that GDCs engage in appropriate long-term planning that accords with their duty to secure capacity in a manner consistent with protecting and preserving the environment. By doing so, individual BGSS proceedings will transpire against the backdrop of GDCs long-term gas planning, and be consistent with statutory requirements and state climate goals.

V. The BPU must create processes that facilitate stakeholder participation and transparency.

The LEI Study demonstrates the critical importance of ensuring that stakeholders have full status and rights in BPU intrastate project approval, prior approvals for interstate long-term firm transportation contracts, and biennial gas planning proceedings. The LEI Study emphasized that planning is critical, as is the ability to “[e]xamine GDC design day firm demand outlooks

In the Matter of the Analysis of the Gas Purchasing and Hedging Strategies of the New Jersey Gas Utilities, Docket No. GA05121062 (Feb. 25, 2009) (authority for overall gas purchasing strategies).

critically and carefully and ensure the GDCs provide transparency in their demand models and assumptions.”⁴⁰ Furthermore, in recommending that BPU should develop enforceable rules to avoid demand shortfalls, the LEI Study observes that a lengthier process requiring “stakeholder consultation and input,” is worthwhile because the “formalization” of rules is more reliable than mere recommendations.⁴¹

BPU could achieve more open proceedings in a number of ways. BPU could make comments and submissions in these proceedings part of the Board’s decisional record, with a requirement that the Board respond to and consider those materials, or it could accord party/intervener status to public interest groups wishing to participate, ensuring they have the right to present evidence and cross-examine witnesses. According party status to public interest groups and other stakeholders is common practice in many state Public Utility Commissions, including New York and Washington, D.C.⁴²

In the absence of such participation, valuable information may also be shuttered from decision makers. As set out above, in BPU’s review of NJNG’s SRL project, it excluded data

⁴⁰ See LEI Study at 86.

⁴¹ LEI Study at 17.

⁴² See, e.g., *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Niagara Mohawk Power Corporation d/b/a National Grid for Electric Service*, NY PSC Case 20–E-0380, Procedural Ruling at 2, issued by Administrative Law Judges Costello & Moreno (Sept. 3, 2020) (granting party status to 23 parties because “their intervention as parties is likely to contribute to the development of a complete record”); *In the Matter of the Implementation of Electric and Natural Gas Climate Change Proposals*, DC PSC Formal Case No. 1167, Order 20754 at 4 (June 4, 2021) (granting petitions to intervene of Sierra Club, EDF, D.C. Government and D.C. Climate Action because “the Commission determines that [the parties] demonstrate a substantial interest in the issue to be presented in this proceeding and a unique perspective that would aid the Commission in evaluating proposals filed in this proceeding”); *In the Matter of the Investigation into Electric Service Market Competition and Regulatory Practices*, DC PSC Formal Case No. 945, Order 14568 at 8 (Oct. 12, 2007) (stating that the Commission “has considerable discretion to grant or deny” a petition to intervene, and “has historically been very liberal in granting intervention.”).

and modeling from its record of proceeding because it was proffered by a party lacking intervenor status.⁴³ There, the lack of a robust record led to BPU approving a project that led to exorbitant ratepayer costs⁴⁴ without the Board's apprehension of TETCO's bidirectional flow and alternatives available that could have addressed the single point of failure scenario upon which the project was predicated.⁴⁵

VI. Conclusion

The LEI Study demonstrates that there is adequate pipeline capacity available to supply New Jersey GDCs through 2030, and that more transparency and clear rules are needed around gas demand estimates and utility supply planning. The BPU should commence a long-term gas planning proceeding aligned with state GHG reduction goals. As described above, it is critical that such a process be open and transparent, allow for full stakeholder participation, and that GDCs seeking additional supply supporting new capacity are required to present factual evidence showing that there is no other cost-effective way to meet demonstrated need. As BPU plans to implement New Jersey's clean energy laws, the Energy Master Plan, and GHG reduction

⁴³ See Exhibit B at 9; *In the Matter of the Petition of New Jersey Nat. Gas Co. for A Determination Concerning the S. Reliability Link Pursuant to N.J.S.A. 40:55d-19 & N.J.S.A. 48:9-25.4*, No. GO15040403, 2016 WL 1159116 (Mar. 18, 2016) (“Only parties, including those who have been granted intervenor status under N.J.A.C. 1:1-16.1, have the right to present testimony at an evidentiary hearing on the issues to be determined through the hearing. As a participant, PPA does not have the right to introduce testimony into the record . . . the Board will consider [the Skipping Stone study] as public comments but afford them no evidentiary value.”)

⁴⁴ See, e.g., <https://www.nj.com/news/2021/04/county-officials-slam-25-rate-hike-proposed-by-nj-natural-gas.html> (NJNG requesting 25% rate hike to offset costs including SRL)

⁴⁵ See Exhibit B at 8 (“SRL was not intended to serve new load, but rather was intended to provide additional reliability of service to its service areas on the southern end of its service territory.”)

mandates and goals, it must simultaneously create a regimented gas planning process that ensures ratepayers are not on the hook for new unneeded, uneconomic, environmentally damaging infrastructure that pushes the clean energy transition further from reach.

Dated: February 8, 2022

Respectfully submitted,

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EXHIBIT A

FILED COMMENTS OF THE ENVIRONMENTAL DEFENSE FUND
AND NEW JERSEY CONSERVATION FOUNDATION
(May 13, 2021)

**STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES**

In the Matter of Natural Gas Commodity and Delivery Capacities in the State of New Jersey – Investigation of the Current and Mid-Term Future Supply and Demand	BPU Docket No. GO20010033
In the Matter of the Exploration of Gas Capacity and Related Issues	BPU Docket No. GO19070846

**COMMENTS OF THE ENVIRONMENTAL DEFENSE FUND AND NEW JERSEY
CONSERVATION FOUNDATION**

Pursuant to the New Jersey Board of Public Utilities’ (“Board” or “BPU”) April 20, 2021 Public Notice establishing a comment deadline of May 13, 2021, Environmental Defense Fund (“EDF”) and New Jersey Conservation Foundation (“NJCF”) submit the following timely-filed comments. EDF and NJCF set forth below a framework that should guide the Board’s threshold inquiry in this proceeding pertaining to whether “the current and future natural gas supply and infrastructure will continue to meet New Jersey’s demands, as well as how evolving environmental concerns may drive changes in the way natural gas is transported and used in New Jersey.”¹ Because the 2019 Energy Master Plan will dramatically change the way gas is used and transported within the state, the Board should adopt an updated gas planning review process that aligns with the state’s clean energy and climate objectives, consistent with the Board’s broad, existing authority to review “overall gas purchasing strategies.”² Finally, our comments provide a list of critical components for a successful planning framework, including a robust long-term plan tied to ultimate cost recovery, all-in cost metrics, a framework to compare non-

¹ *In the Matter of the Exploration of Gas Capacity and Related Issues*, Docket No. GO19070846, Order Soliciting Independent Consultant at page 4 (May 5, 2020) (“May 2020 Order”).

² *In the Matter of the Analysis of the Gas Purchasing and Hedging Strategies of the New Jersey Gas Utilities*, Docket No. GA05121062 (Feb. 25, 2009).

pipeline alternatives with traditional solutions, a standard method for assessing greenhouse gas emissions, and coordinated gas and electric utility planning.

I. Background

In a February 27, 2019 Order in Docket No. GO17121241, the Board directed Staff to initiate a stakeholder process to determine whether sufficient natural gas capacity “has been secured to serve all of New Jersey’s firm natural gas customers as well as whether and to what extent [Third-Party Suppliers (“TPSs”)] are saving customers money on their natural gas supply.”³

In the course of the stakeholder process, New Jersey Natural Gas (“NJNG”) submitted comments on October 16, 2019, which included a report by Levitan & Associates, Inc. (“LAI”) commissioned by NJNG.⁴ In response, EDF and NJCF (collectively “EDF/NJCF”) submitted comments on October 22, 2019 disputing some portions of the LAI report, and included an affidavit of Greg Lander, President of Skipping Stone, who conducted an analysis, on behalf of EDF/NJCF, of natural gas pipeline capacity and supply that has historically served and has been available to serve demand in New Jersey.⁵ The LAI Report and Lander Affidavit reached different conclusions about the medium and long-term capacity needs; and while the respective reports reached different conclusions regarding *future needs, neither report identified a near-term capacity shortfall*.⁶

³ *In the Matter of the Verified Petition of the Retail Energy Supply Association To Reopen the Provision of Basic Gas Supply Service Pursuant To the Electric Discount and Energy Competition Act, N.J.S.A. 48:3- 49 et seq., and Establish Gas Capacity Procurement Programs*, Docket No. G017121241, Order at page 5 (February 27, 2019).

⁴ NJNG LAI Report dated July 12, 2019.

⁵ EDF/NJCF Affidavit of Greg Lander, President, Skipping Stone, dated October 21, 2019.

⁶ Absent an unforeseen, catastrophic disruption of the interstate pipeline network.

During its December 20, 2019 agenda meeting, the Board directed Staff to take the necessary steps to hire a consultant to independently examine the current and future natural gas capacity outlook for New Jersey. On May 20, 2020, the Board issued an Order, stating that it “recognizes the importance of determining if the current and future natural gas supply and infrastructure will continue to meet New Jersey’s demands, as well as how evolving environmental concerns may drive changes in the way natural gas is transported and used in New Jersey.” The Board directed Staff to issue an RFQ for selection of a consultant experienced in the following capacity analysis tasks:

- Perform the infrastructure, demand, contracts, market and other analysis and research set forth in the Scope of Work (“SOW”);
- Review the LAI Report and Lander Affidavit submitted and/or referenced in the Board’s recent statewide Gas Capacity Proceeding;
- Assist Staff in assessing the risk of a shortfall in natural gas capacity in the medium term, considering the normal factors but also considering the effects of Energy Efficiency and conservation expected as the New Jersey 2019 Energy Master Plan is implemented; and
- Assist Staff in developing a robust set of non-pipe mitigation measures, as described (but not limited to those) in the SOW.

On April 20, 2021, the Board issued a Notice soliciting stakeholder feedback on design day issues and non-pipe alternatives. The Board held a stakeholder meeting on April 29, 2021 to discuss the list of issues identified in its April 20, 2021 Notice, among others.

II. Comments

A. The Board Must Identify Demand for Gas Capacity, Evaluate All Capacity to Meet Demand, and Direct Gas Distribution Companies (“GDCs”) to Obtain Sufficient Capacity to Meet All Firm Customer Needs

The central inquiry in this proceeding is determining “if the current and future natural gas supply and infrastructure will continue to meet New Jersey’s demands, as well as how evolving environmental concerns may drive changes in the way natural gas is transported and used in New

Jersey.”⁷ While the specific questions listed in the most recent Public Notice focus on a narrow subset of issues, answering the Board’s initial question posed in the May 20, 2020 Order will require an assessment of the following:

- (1) identify the demand for gas capacity that GDCs should plan for and which ensures sufficient reliability;
- (2) evaluate both secured capacity⁸ and available capacity⁹ to meet demand and reliability targets; and
- (3) (a) if a capacity constraint is identified, assess the most cost effective and environmentally beneficial solution using a transparent and competitive RFP process; and (b) direct GDCs to obtain sufficient capacity to meet all firm customer needs “in a manner that tends to conserve and preserve the quality of the environment.”¹⁰

As the Board observed in its initial order, analysis of these issues cannot be divorced from the Energy Master Plan, which will dramatically change the way gas is used and transported within the state. Going forward, these questions should be addressed within an updated gas planning framework that aligns with the state’s clean energy and climate objectives.

1. Identify Demand for Gas Capacity that Ensures Sufficient Reliability

The first step in the process is to identify demand for gas capacity that ensures sufficient reliability. As explained below, the 1-in-30 design day criteria is the appropriate standard to ensure reliability based on an evaluation of extreme temperature data. The Board must first provide guidance regarding who is responsible for providing capacity reliability for the demands of firm customers sold gas by a TPS; and if that responsibility does not belong to the GDCs, how

⁷ May 2020 Order at page 4.

⁸ Here, secured capacity is that capacity contracted directly from pipelines to serve New Jersey GDC delivery locations plus delivered service capacity contracted with third party holders of pipeline capacity contracts which, based on pipeline scheduling rules, is able to serve New Jersey GDC locations.

⁹ Here, available capacity refers to capacity which, based on pipeline scheduling rules is capable of serving New Jersey GDC delivery locations and which is in addition to secured capacity.

¹⁰ N.J.S.A. § 48:2-23.

any such capacity reliability requirement is verified and enforced over time.¹¹ The Board must then establish reliability criteria and mechanisms for determining all GDCs and TPSs' firm customers' needs.

The differences, if any, between reliability and resiliency should be articulated, especially in the context of interstate pipeline rules. Several interstate pipeline tariffs' General Terms and Conditions provide for the proration of impaired deliveries. For example, Algonquin's tariff provides that in the event of an emergency situation, service would be interrupted or curtailed in the order provided in Section 24.4, starting with scheduled service for park and loan service (the lowest priority of interruptible service) and ending with prorated scheduled service under all firm service agreements.¹² In other words, no firm incremental service, or addition of a firm lateral or delivery point service, overcomes the fact that all firm services suffer equally when an emergency arises. Therefore, if a project is offered to meet a "reliability" or "resilience" need, there should be a heightened burden to show that project somehow overcomes the operation of the pipeline's pro-rata curtailment and scheduling provisions of its tariff. The GDC should have to demonstrate, with sufficient detail, the resilience problem asserted to be addressed, the likelihood the event would occur, how the project would solve that problem, and other alternatives considered to address the asserted problem. The Board should view, with particular scrutiny, any "reliability" or "resilience" project where the shipper is the owner/beneficiary of revenues from the project.

¹¹ While New Jersey regulations require TPSs, as part of being licensed in New Jersey, to "meet all of the ... applicable reliability standards and requirements of the Federal Energy Regulatory Commission," there are no such 'reliability standards' as related to either retail or wholesale gas suppliers articulated in Federal regulations. *See* N.J.A.C. 14:4-5.2(f)(4) (Basic requirements for an electric power supplier, gas supplier or clean power marketer license).

¹² *See, e.g.*, Algonquin Gas Transmission, LLC FERC Gas Tariff, General Terms and Conditions at Section 16.3, available at <https://infopost.spectraenergy.com/infopost/AGHome.asp?Pipe=AG>.

In the planning process, firm customers' design day and design hour should be established by the GDCs, including the articulation of the methodology employed by the GDCs for determining firm customers' design hour and design day demands, respectively.

In addition, the planning process should identify the design day and design hour of non-firm customers so that the GDCs, the BPU and interested stakeholders can come to know and assess the differences between these loads (firm and non-firm) and whether current non-firm customers' obligations for alternate fuel or shutdown¹³ are realistic, appropriate, and enforceable.

Once reliability criteria have been established, each GDC should then project future gas demand and: 1) incorporate impacts of electrification on demand profiles in determining peak gas demand, as policies regarding electrification are formalized; and 2) incorporate energy efficiency and demand response programs as components of meeting the demand profile. In particular, the demand forecast should project peak gas demand (hour and day) for electric generation that results from electrification and consider the net impact on peak gas demand. If there is a net reduction in gas consumption for electricity during peak periods, the analysis should assess whether reductions would occur at gas plants in New Jersey or elsewhere in PJM.

2. Evaluate Available Capacity to Meet Demand and Reliability Targets

Once the correct level of demand has been identified, the Board will next need to assess current contracts for capacity held by GDCs, including an assessment of available capacity that could be solicited and be reliably obtained (i.e., secured) to address demands in excess of current contracts for capacity held by GDCs. The following issues will need to be addressed as part of this step:

¹³ Alternate fuels' emission differences, as well as whether human needs loads like schools,' hospitals' and others' heating and/or cogeneration loads could/should continue to be subject to interruption are currently under review in other jurisdictions.

- As discussed above, identify the entity responsible for planning and assuring sufficient capacity (with or without contracting for supply through that capacity). In this vein, mandatory release of capacity obtained to meet firm demands for gas on the GDCs' systems, but not receiving BGSS service, should be revisited.
- Address the difference between secured capacity and available capacity.¹⁴
- Include capacity held by third parties.

The BPU should periodically assess the capacity service available to New Jersey as well as the measurement of capacity service “secured” for New Jersey—whether that capacity service is “secured” directly from pipelines or is existing capacity service held by others but contracted as delivered service to New Jersey location(s). These three assessments (i.e., secured by GDCs directly from pipelines, secured by GDCs indirectly from holders of capacity on pipelines that are committing to delivered service to GDC location(s) and available unsecured capacity) should be performed by the BPU Staff or by consultant(s) to the BPU Staff following an agreed upon definition of “secured” and “available unsecured.”¹⁵

3. Direct GDCs to Obtain Sufficient Capacity to Meet All Needs in a Manner that is Consistent with the Obligation to Preserve and Conserve the Quality of the Environment

The Board should then direct GDCs to obtain sufficient capacity to meet all firm needs, including firm customers served by TPSs, and institute mandatory release programs to TPS so

¹⁴ For example, assurance can take the form of securing capacity directly from pipelines as well as securing contracts for multi-year peak period delivered service contracts, which contracts could be structured so as to have staggered maturities such that the GDCs have the assurance of capacity service to meet identified demand well into the future. On the other hand, available capacity is that which can be (and may have previously been) employed to meet New Jersey demand but is not currently contractually committed to serving a peak period New Jersey demand.

¹⁵ EDF/NJCF have proposed definitions in these comments as a starting place, which can be refined going forward to establish a shared understanding going into the planning process.

that there is neither risk to reliability nor risk associated with verification of TPS capacity.¹⁶

Where the periodic and recurring gas planning process identifies a GDC capacity need, the Board should encourage the GDC to solicit multi-year peak period delivered service contracts to use existing capacity. This would eliminate the concern of GDCs that delivered service contracts may not be available “next year.”

There must be a robust and transparent means to compare gas capacity expansion with non-pipeline alternatives, and EDF/NJCF propose below a framework for comparison. Given that unnecessary gas capacity expansion is incompatible with state climate targets¹⁷ and could lead to increased costs due to stranded assets, heightened scrutiny must be applied to these proposals, particularly if supported by affiliated entities. All non-pipeline alternatives (i.e., LNG, CNG, RNG, hydrogen, Demand Response, EE, and/or electrification) should be evaluated against existing and future traditional pipeline infrastructure solutions in a manner that enables a transparent assessment of costs and benefits.

B. The Board’s Existing Practices are Insufficient to Ensure Gas Supply Decisions Comply with the State’s Climate Goals

To date, there remains a significant disconnect between the Board’s implemented regulation of GDCs and the State’s ambitious climate goals. The existing processes by which GDCs submit planning information are deficient and do not allow for a thorough weighing of alternatives. GDCs also continue to rely on business as usual scenarios, assumptions, and programs that will hinder the State’s ability to reduce GHG emissions. The Board’s ability to perform its regulatory duty of ensuring adequate service “in a manner that tends to conserve and

¹⁶ Additionally, issues related to TPSs which now hold (i.e., have secured) firm capacity for multi-year periods, to serve firm New Jersey customers, can be addressed so that a mandatory release program assures reliability without unintentionally leading to near-term doubling up of capacity.

¹⁷ It is also incompatible with GDCs’ duty to serve in a manner that preserves the quality of the environment.

preserve the quality of the environment”¹⁸ is premised upon receiving sufficient information and analyses from the GDC initiating the request. To date, however, GDCs have not provided the tools or means to assess and weigh climate impacts.

Although the Board has broad authority to review GDCs’ “overall gas purchasing strategies,”¹⁹ it does not currently have a rule requiring GDCs to address gas planning in base rate cases or anywhere else. The rule addressing general rate cases, N.J.A.C. 14:1-5.12, titled “Tariff Filings or Petitions That Propose Increases in Charges to Customers” requires basic financial information and, unlike many state rules on rate cases, does not require any pre-filed testimony.²⁰ To date, these filings have continued to reflect a business-as-usual mindset. For example, in the New Jersey Natural Gas base rate case filed on March 30, 2021 in BPU Docket No. GR21030679, the Company states that capital investments have resulted in an approximate \$540 million increase in utility plant in service. The impact of this rate request on the average residential heating customer using 100 therms per month is a \$28.07 increase in the customer’s monthly bill, from \$113.10 to \$141.17—nearly a 25% increase.²¹

The Company proposes to recover the costs of distribution gas mains over 75 years, and gas services over 67 years, as detailed in the chart below:

¹⁸ N.J.S.A. § 48:2-23.

¹⁹ In the Matter of the Analysis of the Gas Purchasing and Hedging Strategies of the New Jersey Gas Utilities, Docket No. GA05121062 (Feb. 25, 2009).

²⁰ GDCs provide pre-filed testimony in New Jersey due to the common practice and the expectation of BPU Staff.

²¹ <https://www.njng.com/regulatory/pdf/NJNG-2021-Base-Rate-Case-Filing-GR21030679.pdf>.

Account Description A	Current Parameters						Proposed Parameters					
	P-Life/ AYFR B	Curve Shape C	VG ASL D	Rem. Life E	Avg. Sal. F	Fut. Sal. G	P-Life/ AYFR H	Curve Shape I	VG ASL J	Rem. Life K	Avg. Sal. L	Fut. Sal. M
STORAGE AND PROCESSING PLANT												
361.00 Structures and Improvements	2068	200-SC	64.53	46.27	-9.5	-10.0	2068	200-SC	61.85	44.53	-9.6	-10.0
362.00 Gas Holders	2068	200-SC	77.90	46.13	-40.3	-40.0	2068	200-SC	77.79	44.39	-40.3	-40.0
363.20 Vaporizing Equipment	2068	35-R5	35.22	23.61	49.6	50.0	2068	35-R5	35.55	21.95	49.6	50.0
363.30 Compressor Equipment	2068	35-R5	35.73	19.06	-4.9	-5.0	2068	35-R5	35.94	17.41	-4.9	-5.0
363.40 Measuring and Regulating Equipment	2068	35-R5	35.13	29.61	-5.1	-5.0	2068	35-R5	35.24	27.79	-5.1	-5.0
363.50 Other Equipment	2068	35-R5	37.50	5.09	-4.5	-5.0	2068	35-R5	39.88	4.35	-4.5	-5.0
Total Storage and Processing Plant									39.25	25.86	2.4	3.1
TRANSMISSION PLANT												
366.00 Structures and Improvements	2034	200-SC	39.18	15.18	-9.8	-10.0	2034	200-SC	39.30	13.26	-9.8	-10.0
367.00 Mains	70.00	S4	69.92	53.94	-58.9	-60.0	70.00	R3	70.10	54.86	-92.1	-90.0
369.00 Measuring and Regulating Equipment	50.00	L0	50.24	43.51	-74.5	-75.0	46.00	L1	45.99	36.99	-70.1	-70.0
Total Transmission Plant									63.66	50.00	-87.5	-86.0
DISTRIBUTION PLANT												
375.01 Structures and Improvements	65.00	L1.5	65.39	46.76	-3.0	-5.0	70.00	L1.5	70.30	52.82	-3.3	-5.0
376.00 Mains - Steel	77.00	S1.5	77.09	55.88	-87.6	-93.0	75.00	S2	74.96	55.28	-112.0	-90.0
376.26 Mains - Plastic	70.00	S4	69.96	59.50	-59.6	-60.0	65.00	S2	65.00	55.12	-92.3	-90.0
378.00 Meas. and Reg. Station Equip. - General	35.00	L0.5	35.23	26.13	-78.8	-75.0	37.00	L0.5	37.05	29.94	-78.1	-75.0
380.01 Services - Steel	70.00	L0	72.26	51.31	-38.7	-60.0	65.00	R0.5	67.01	41.89	-176.5	-90.0
380.21 Services - Plastic	70.00	S3	69.85	56.17	-58.0	-60.0	60.00	S3	59.85	46.17	-97.6	-90.0
381.00 Meters	35.00	L2	35.07	27.40	-3.8		38.00	L1.5	38.08	29.99	-3.4	
382.00 Meter Installations	38.00	L1.5	38.22	28.54	-54.4	-50.0	38.00	L1	38.39	29.12	-59.8	-50.0
383.00 House Regulators												
384.00 House Regulator Installations												
385.00 Meas. and Reg. Equipment - Industrial	40.00	L2	41.92	19.78	-10.4	-10.0	40.00	L2	42.38	18.92	-10.4	-10.0
387.00 Other Equipment	15.00	L0	19.07	8.33	-14.1	-15.0	15.00	L0	20.08	7.95	-14.7	-15.0
Total Distribution Plant									59.89	47.52	-91.7	-82.7

While an assumed useful life of 67 years or longer may have been appropriate in a pre-climate crisis paradigm, the mismatch between the time horizon of these new investments and climate goals exposes both gas utilities and their customers to new risks of under-collecting or even needlessly stranding infrastructure. Utilities are starting to recognize the incompatibility between continued investment in long-lived infrastructure and achievement of climate objectives. Consolidated Edison Company of New York Inc.’s Joint Proposal, approved by the New York Public Service Commission, obligates the Company to file a study on “the potential depreciation impacts of climate change policies and laws on its gas, electric, steam, and common assets.”²² Corning Natural Gas Corporation in New York states that, as a consequence of New York’s climate law, Corning’s assets (and improvements that reduce GHG emissions) should be

²² *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Gas Service*, Case 19-G-0066 Joint Proposal at 113 (Oct. 18, 2019), <http://documents.dps.ny.gov/public/MatterManagement/MatterFilingItem.aspx?FilingSeq=234578&MatterSeq=58902>.

permitted to have “depreciable lives [that] match the expected economic lives of utility assets.”²³

The Board will have to carefully assess this issue going forward, with particular focus on protecting low-income customers from the death-spiral effect of contracting throughput and the collection of fixed costs associated with the same or even a contracting gas system.

Another process in need of enhancement is the Basic Gas Supply Service (“BGSS”) proceedings. Since the 1999 restructuring of the gas distribution business to allow competition in providing gas supply, the gas utility provision of gas supply is through the BGSS. BGSS rate petitions are filed by each gas utility annually around June 1. The filings and proceedings follow provisions of the applicable utility tariff. Those tariffs place the focus of those proceedings on the costs to be recovered through the new proposed BGSS rate – not planning.²⁴ BPU does not currently require GDCs to submit long-term planning information in the BGSS proceedings to place any of the rate requests into broader context. For example, none of the GDCs provided comprehensive information on the planning or justification for their investment in the affiliate-

²³ *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Corning Natural Gas Corporation for Gas Service*, Case 20-G-0101, Direct Testimony of Firouzeh Sarhangi at FS-5 (Feb. 27, 2020), <http://documents.dps.ny.gov/public/MatterManagement/MatterFilingItem.aspx?FilingSeq=241529&MatterSeq=62108>.

²⁴ For example, the Elizabethtown Gas Company tariff defines the BGSS process as follows:

The filing shall provide for a review of the actual costs and recoveries for the previous period ending April 30 and projections of costs and recoveries through September 30. The filing shall also propose a new BGSS-P rate to be implemented on October 1. The proposed BGSS-P rate shall be based upon the projected cost of purchased gas and storage utilization to serve projected demand for gas service for the period October 1 through September 30 and an adjustment to recover or credit prior period under or over recovered gas costs as projected to exist on the preceding September 30. The Company shall provide the basis for its projected costs and the NYMEX projection of monthly gas prices for the projected period. In its annual filing the Company shall calculate the CCC-P component, as defined above, of the BGSS-P rate. Adjustments, if any, resulting from the Board’s review of this filing shall be made following a Board Order.

Elizabethtown Gas Company B. P. U. NO. 17 – GAS ORIGINAL SHEET NO. 108 (Nov. 14, 2019).

backed PennEast Pipeline.²⁵ To address these deficiencies, the Board will need to update and refine implementation of its existing regulatory tools to ensure that they align with the State’s climate objectives.

C. New Jersey Needs a Long-Term Gas Planning Process that is Transparent, Holds GDCs Accountable, and Ensures Alignment with Climate Objectives

In July 2019, Governor Murphy signed into law amendments to the Global Warming Response Act (“GWRA”). First passed in 2007 and since amended, the GWRA introduced a fixed goal of reducing GHG emissions by 80% from their 2006 levels by 2050. The New Jersey Department of Environmental Protection issued its 80x50 report, as required by the GWRA, on October 15, 2020. One of the key findings from the report is that:

Residential and commercial buildings account for the second largest share of (26%) of the state’s GHG emissions, accounting for 24.6 MMT CO₂e in 2018. In order to achieve the 80x50 goals, emissions from the residential and commercial sectors must be reduced by 89% to 2.7 MMT CO₂e by 2050. Space and water heating account for the majority of the emissions, with 87% of residential buildings and 82% of commercial building relying predominately on natural gas.²⁶

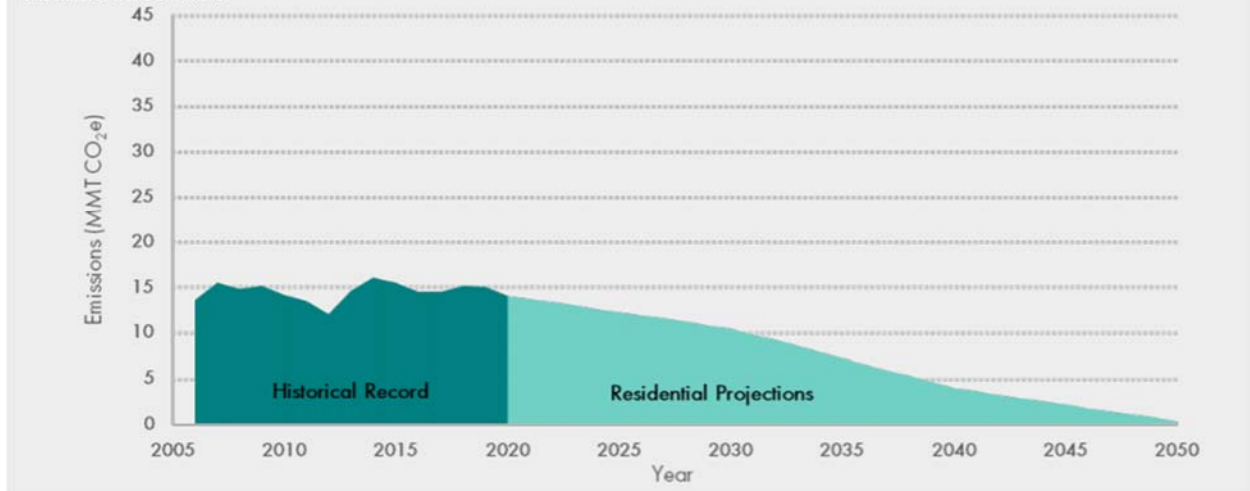
As shown in the graph below depicting the residential sector, the least cost scenario modeling performed for the 2019 Energy Master Plan (“EMP”) calculated that 90% of buildings must be converted to 100% clean energy systems to meet the 2050 emissions goals:

²⁵ *In the Matter of the Petition of New Jersey Natural Gas Company for the Annual Review and Revision of its Basic Gas Supply Service (BGSS) and Conservation Incentive Program (CIP) Rates for F/Y 2020*, Motion of the Environmental Defense Fund, BPU Docket No. GR19050676 at page 3 (June 17, 2019) (explaining that the petition was conspicuously silent on NJNG’s contractual commitment for service on its affiliate’s PennEast Pipeline).

²⁶ New Jersey’s Global Warming Response Act 80x50 Report, <https://www.nj.gov/dep/climatechange/docs/nj-gwra-80x50-report-2020.pdf>.

Figure ES.5. Residential Sector Historical GHG Emissions & Projected Pathway to 2050 (MMT CO₂e).

Converting space heating and hot water applications to electricity, using electric appliances, and improving energy efficiency will bring substantial reductions to the residential sector's emissions.



The 80x50 Report asserts that it is necessary for New Jersey to implement both a unified energy policy as set forth in the 2019 EMP and sector-specific policies to achieve the level of GHG reductions called for by the GWRA.²⁷

One of the key inquiries in this proceeding is consideration of how the EMP will impact natural gas use in the state going forward.²⁸ The EMP sets forth a strategic vision for the production, distribution, consumption, and conservation of energy in the state.²⁹ It incorporates rigorous climate goals and spans multiple sectors and governmental agencies, including the Board. Various strategies in the EMP could have significant implications for the management of gas supply portfolios, including, among others:

- The finding that “the building sector should be largely decarbonized and electrified by 2050 with an early focus on new construction and the electrification of oil- and propane-fueled buildings” (Page 13); and
- The development of a “transition plan to a fully electrified building sector, including appliances like electrified heat pumps and hot water heaters” (Page 14).

²⁷ *Id.* at page vii.

²⁸ May 2020 Order at page 3, 4.

²⁹ https://nj.gov/emp/docs/pdf/2020_NJBPU_EMP.pdf.

Such strategies and goals underscore the importance of considering the impact of current and future state policies on prospective gas demand and supply needs. Rigorous electrification policies will impact gas capacity needs and uses, which will in turn require thoughtful planning of the rate recovery of gas infrastructure, including whether creative financing mechanisms such as accelerated depreciation are needed in order to calculate the appropriate useful life of an asset.³⁰ The EMP strategies also underscore the importance of requiring gas utilities to demonstrate that their gas portfolio decisions conform to and are consistent with State climate policy and greenhouse gas reductions goals. As the Board has previously found, the “actions, decisions, determinations and rulings of State government entities with respect to energy ‘shall to the maximum extent practicable and reasonable and feasible conform’ with the provisions of the EMP.”³¹

Going forward, the Board should take the foundational step of improving its gas supply planning processes to ensure that gas supply decisions comply with the state’s ambitious climate goals. The Board has previously found that the annual BGSS proceedings should involve review of gas utility “overall gas purchasing strategies.”³² To fulfill this objective, the Board needs an enhanced planning framework with which it can assess whether a GDC gas portfolio “provides maximum benefit” to customers, as specified in the statute.³³ Below is a list of critical components for a successful planning framework, informed by the recommendations set forth in

³⁰ See generally Environmental Defense Fund, *Managing the Transition – Proactive Solutions for Stranded Gas Asset Risk in California* (2019), https://www.edf.org/sites/default/files/documents/Managing_the_Transition_new.pdf.

³¹ *In the Matter of the Petition of New Jersey Natural Gas Company for a Determination Concerning the Southern Reliability Link Pursuant to N.J.S.A. 40:55D-19 and N.J.S.A. 48:9-25.4*, Decision and Order, Docket No. GO15040403 at pages 118-119 (March 18, 2016) (citing N.J.S.A. 52:27F-15(b)) (emphasis supplied).

³² *In the Matter of the Analysis of the Gas Purchasing and Hedging Strategies of the New Jersey Gas Utilities*, Docket No. GA05121062 (Feb. 25, 2009).

³³ N.J.S.A. §48:3-58u.

EDF’s White Paper “Aligning Gas Regulation with Climate Objectives”³⁴ as well as proposals offered before other state commissions, such as the New York Public Service Commission Staff’s Gas Planning Proposal.³⁵

1. Long-Term Plan tied to BGSS Process

To date, GDCs are not required to submit any kind of long-range plan. This is in stark contrast to other state practices, which require detailed planning documents as a core feature of regulatory oversight.³⁶ GDCs should be required to submit a long-range plan,³⁷ which would set forth projections of demand, by peak hour by operational “division” and by day by operational “division.” Against that demand, the resources to meet that demand should be set based upon the contracts and the on-system supply capabilities of the GDC. GDCs should then identify the cost of each resource (fixed costs and projected or known variable costs) and the projected load factor utilization of the resources so that all-in costs (discussed in detail immediately below) can be reviewed and alternatives that might result in lower all-in cost(s) be evaluated. An agreed-upon long range plan would become the basis for the annual BGSS proceedings. Then, in the annual BGSS proceedings, the long range plan would provide the baseline. Differences between the

³⁴ Environmental Defense Fund, *Aligning Gas Regulation and Climate Goals: A Road Map for State Regulators*, (Jan. 2021), <http://blogs.edf.org/energyexchange/files/2021/01/Aligning-Gas-Regulation-and-Climate-Goals.pdf>.

³⁵ *Proceeding on Motion of the Commission in Regard to Gas Planning Procedures*, Case 20-G-0131, Staff Gas System Planning Process Proposal (Feb. 12, 2021).

³⁶ *See, e.g.*, Boston Gas Company d/b/a National Grid Long-Range Resource and Requirements Plan (November 1, 2018), <https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/10008562>.

³⁷ Narragansett Electric Company’s recent Gas Long-Range Resource and Requirements Plan could serve as a helpful model: [http://www.ripuc.org/eventsactions/docket/4816-NGrid-Compliance%20with%20Division%20\(7-2-19\).pdf](http://www.ripuc.org/eventsactions/docket/4816-NGrid-Compliance%20with%20Division%20(7-2-19).pdf).

baseline and the actuals/projections in the gas cost reconciliation proceeding would be evaluated as “variances from plan.”³⁸

A joint proposal submitted by Rhode Island Staff and the utility to the Rhode Island Public Utilities Commission (“RIPUC”) employs a similar process to align the gas utility’s long-term plan with its annual gas cost recovery. Under this framework, Narragansett Electric Company (the GDC d/b/a National Grid) submits a long-range plan that is subject to approval by the RIPUC and uses the same forecasts from the long-range plan in its annual gas cost reconciliation filings, such that the gas cost reconciliation will be “a proceeding that effectively reconciles costs from known and supported commitments.”³⁹ The utility “shall prepare a comparison of volumes and costs presented in its GCR [gas cost reconciliation] filing in the same form (i.e., presentation format) as its annual LRP [long-range plan] filing from June of the same year and identify any differences,” which ensures that “[b]y the time the GCR is filed, these items found in the Company’s LRP submission will have already been fully vetted.”⁴⁰

Connecting the long-range plan to the information presented in the BGSS proceedings will allow for the presentation of potential resources, their timing, all-in costs, and capabilities to assist the Board in both understanding the available alternatives and the trade-offs involved with each.

2. All-in Cost Metric

As New Jersey works to achieve its climate objectives, there is a need for a transparent demonstration of the true demands of the gas system and the all-in costs of meeting that demand

³⁸ *Id.* at pages 40-41.

³⁹ *Gas Long-Range Resource and Requirements Plan for the Forecast Period 2017/18 to 2026/27*, RIPUC Docket No. 4816, Joint Memorandum of the Narragansett Electric Company d/b/a National Grid and the Division of Public Utilities and Carriers at page 3 (Feb. 20, 2019).

⁴⁰ *Id.* at page 7.

with various resources, being mindful not to lock-in greenhouse gas emissions from unnecessary long-lived and possibly stranded infrastructure. To ensure that the planning process facilitates fulsome consideration of these issues, GDCs should be required to calculate and report the all-in costs of different proposals.

Existing metrics do not allow for easy comparison of the varied supply and demand options GDCs might consider. To address this deficiency, the Board should require the use of the all-in cost metrics to compare the true costs of different supply provision and/or demand reduction options. This will help the Board, BPU Staff, GDCs, and interested stakeholders compare different options and ensure that costs to ratepayers are minimized appropriately.

There are two related all-in cost metrics. One is the Design Day all-in cost per Dth metric. The other is the load factor sensitive all-in cost per Dth of estimated use metric. The Design Day all-in cost is determined by looking at the pertinent facility's/asset's fixed costs (including fixed O&M, if any) divided by the Design Day quantity of Dth provided (or saved) by the pertinent facility/asset/program; plus, the pertinent facility's/asset's/program's variable commodity/O&M cost per unit of demand to be met on a peak day.

Similarly, the all-in cost per Dth of estimated use (i.e., annual demand) to be met (i.e., taking into account the load factor of the annual demand to be met), looks at the same total annual fixed costs (including fixed O&M, if any) plus the annual variable commodity/O&M cost of the annual load served divided by the quantity of annual load met by the pertinent facility/asset/program. The two metrics, applied to capital projects, capacity plus supply contracts, delivered service contracts, energy efficiency and/or demand response measures allows for an apples-to-apples comparison of different supply-side and demand-side options

based on how often over the course of a year they will actually be used (as well as based on design day use). The formulas are provided below:

$$\text{All-In Cost (Design Day)} = \left(\frac{\text{the sum of the fixed cost per year of the project + the fixed O\&M cost (if any) of the project (i.e., total annual non-gas cost)}}{\text{the projected Design Day Dth of use (i.e., quantity) of project (to arrive at modeled per Dth of use non-gas cost)}} \right) + \text{the variable commodity cost per Dth of the project} + \text{the variable O\&M cost per Dth (if any)}$$

$$\text{All-In Cost (Estimated Use)} = \left(\frac{\text{the sum of the fixed cost per year of the project + the fixed O\&M cost (if any) of the project (i.e., total annual non-gas cost)}}{\text{the projected annual use (i.e., quantity) of/by or through the project (to arrive at modeled per Dth of use non-gas cost)}} \right) + \text{the variable commodity cost per Dth of the project} + \text{the variable O\&M cost per Dth (if any)}$$

The example below shows how the all-in cost of estimated use metric could be used in comparing the costs of a CNG facility versus new pipeline capacity:

	Annual Facilities' / Fixed Costs	Annual O&M / Commodity Costs	Peak Hour Demand (Dth/Hr)	Annual Incremental Demand Met	All-in Cost (\$/Dth)
Ex. 1	\$5,000,000	\$1,800,000	1,000	150,000	\$45.33
Ex. 2	\$15,768,000	\$420,000	1,000	150,000	\$107.92
<p>Ex. 1 Assumptions: Annual Cost of CNG Facility is \$5 MM; CNG \$/Dth \$12; Ex. 2 Assumptions: Annual Cost of New build PL Capacity at \$1.80/Dthd; \$/Dth \$2.80; Common Assumptions: 1,000 Dth/Hr (24,000 Dthd); and 150 Hours/Yr Equivalent Full use.</p>					

The all-in cost metrics are critical to weighing the cost of new long-term investment such as new pipeline capacity, which is not used on every day of the year. Solving seasonal constraints with a pipeline solution, as compared to an alternative such as CNG or LNG, would come at

significant cost to ratepayers. This is because the annual fixed costs of new pipeline capacity are significantly higher than these other alternatives; especially when capacity is not needed to meet firm demand every day of the year. The result of high annual fixed costs coupled with low annual use means that the per Dth cost of gas actually used to meet firm demand is quite high. Therefore, the all-in cost metrics can serve as valuable tool in elucidating the least cost option for customers and should be incorporated into an updated planning framework.

3. Framework to Compare Non-Pipeline Alternatives with Traditional Solutions

The Board should consider employing a more systemized approach to comparing alternatives that could either provide natural gas supply or demand relief. EDF/NJCF propose a framework that builds on Consolidated Edison’s December 21, 2017 Request for Proposals submitted in the Smart Solutions proceeding before the New York PSC in Case No. 19-G-0606 and borrows from other state processes used to discipline affiliate transactions.⁴¹ In brief, the GDC would issue a Request for Proposals (“RFP”), seeking a broad array of innovative solutions that could either provide natural gas supply or demand relief.

This competitive-type process would not only protect against affiliate abuse—see discussion immediately below—but would also incentivize Capacity Service Providers⁴² to

⁴¹ See *Application of Pacific Gas and Electric Company for Authorization to Enter into Long-Term Natural Gas Transportation Arrangements with Ruby Pipeline, for Cost Recovery in PG&E's Gas and Electric Rates and Nonbypassable Surcharges, and for Approval of Affiliate Transaction*, California Public Utilities Commission (“CPUC”), Decision 08-11-032, November 6, 2008 Order at 85-93, 118-122 (citing CPUC D.04-09-022; CPUC D.06-12-029, Appendix A-3, Rule III.B.1; CPUC D.04-12-048) (explaining that the CPUC’s rules require utilities to use an open and transparent solicitation process when involving affiliates and have a neutral independent evaluator review solicitations that involve affiliates); Direct Testimony of Greg Lander, Missouri Public Service Commission Case No. GR-2017-0215, GR-2017-0216 at Schedule EDF-06 (September 8, 2017) (proposing modifications to the gas supply and transportation standards of conduct).

⁴² A Capacity Service Provider is an entity that provides, for a price, one or more Capacity Service(s). Capacity Service is defined as one or more asset(s), service(s), product(s) or any combination of same that enables the ultimate need (as defined below) to be met. Examples of Capacity Service Providers

develop solutions that are narrowly tailored (in terms of size and cost) to the ultimate need⁴³ while minimizing costs, GHG emissions, and adverse impacts on communities and the environment.⁴⁴ As a result of this robust and competitive process, the GDC would have several options to choose from and its selection process would be transparent and apparent to the Board and interested stakeholders.

1. [Retail Gas Utility] will use a competitive bidding process in which requests for proposals (RFPs) are submitted by [Retail Gas Utility] to Capacity Service Providers to provide either natural gas-supply or natural gas-demand relief. For any exceptions to the competitive bid and award process, [Retail Gas Utility] will have a documented process for the approval and award process, including (a) justification requirements, (b) authorization process, (c) contemporaneous documentation requirements (for internal Company information and external communications), and (d) effective monitoring and controls. [Retail Gas Utility] will maintain internal controls such that no information regarding the content or subject of communications by and between non-affiliate potential bidders and [Retail Gas Utility] personnel with access to such information shall be communicated or made accessible to personnel of [Retail Gas Utility] affiliate(s).
2. The RFP process shall be open to all Capacity Service Providers who wish to bid and shall be publicly posted on the [Retail Gas Utility's] website and filed with the Commission. The intent is to gain the broadest practical participation by eligible Capacity Service

would include: (1) a pipeline that provides firm transportation service to the Retail Gas Utility or end market served by the Retail Gas Utility; (2) an entity that sells CNG, RNG and/or LNG delivered into the Retail Gas Utility and/or into a pipeline able to effectuate firm incremental delivery to the Retail Gas Utility or end market served by the Retail Gas Utility; (3) an entity that provides a firm, bundled capacity and commodity service to the Retail Gas Utility or end market served by the Retail Gas Utility; (4) demand response providers whose demand response reduces demand of specified end use customers during hours of peak demand – typically early morning and evening periods on peak demand days; and (5) Energy Efficiency providers whose energy efficiency measures reduce demand of specified end use customers during hours of peak demand – typically early morning and evening periods on peak demand days.

⁴³ The ultimate need must be defined clearly and substantiated by the Retail Gas Utility.

⁴⁴ For instance, an interstate pipeline could distinguish its proposal by incorporating additional features that would provide environmental benefit such as enhanced methane reduction measures. *See, e.g.*, Iroquois Spring 2020 Report, https://www.iroquois.com/site/assets/files/1057/spring_2020_safety_issue_web.pdf (“As part of the ExC Project, Iroquois plans to reduce methane and overall emissions at project sites through the installation of low Nitrous Oxide (NOx) turbine units that will reduce NOx emissions by 40% over standard turbine units, as well as adding oxidation catalysts on the newly installed turbines, thereby reducing Carbon Monoxide (CO) emissions by approximately 90%. In addition, Iroquois is proposing to install methane recovery systems at each project site to capture released natural gas from station operations.”).

Providers in submitting competitive bids. Once such a process is reasonably developed, appropriately implemented and effectively monitored and controlled, the results of that process are intended to establish the most innovative solutions to provide natural gas-supply or natural gas-demand relief, considering the all-in cost metrics, GHG emissions, as well as impacts on communities and the environment. [Retail Gas Utility] shall require that proposals quantify the GHG emissions associated with their offer, using an agreed-upon methodology such as the Gas Company Climate Planning Tool.⁴⁵ [Retail Gas Utility] shall provide the Commission with a report, including an explanation of any credit, performance or other criteria that [Retail Gas Utility] takes into consideration in developing the RFP.

3. No affiliate of [Retail Gas Utility] shall be awarded a capacity service contract where such contract would result from an exception to the competitive bid and award process. In the event a capacity service contract is awarded to an affiliate of [Retail Gas Utility] as a result of the RFP or other competitive bidding process, the affiliate shall be held to the same performance requirements as non-affiliated Capacity Service Providers.
4. In the event a capacity service contract is awarded, [Retail Gas Utility] shall maintain the following contemporaneous documentation: (a) any diversity, credit, or reliability-related capacity limitations placed on the maximum capacity [Retail Gas Utility] will purchase from an individual Capacity Service Provider (if applicable); (b) an explanation of the diversity, credit and/or reliability-related reasons for imposing such limitations (if applicable); (c) a description of the process used to evaluate bids, and negotiate final prices and terms; (d) a complete summary of all bids received and all prices accepted, together with copies of all underlying documents, contracts and communications; (f) a summary and explanation of Capacity Service Providers disqualified for credit, performance or other criteria, and (g) a copy of the policy or procedure employed by [Retail Gas Utility] for awarding contracts in instances where an affiliate and an unaffiliated Capacity Service Provider have offered identical pricing terms. For phone calls or texts, [Retail Gas Utility] shall maintain contemporaneous logs documenting the discussions and decisions.
5. In the event a capacity service contract is awarded to an affiliate of [Retail Gas Utility], the [Retail Gas Utility] shall maintain contemporaneous documentation showing that the affiliate's bid price was equal to or lower than the bids received from non-affiliates.
6. In the event a capacity service contract is proposed to be awarded to an affiliate of [Retail Gas Utility] for a capacity path between a supply receipt area and a delivery area along or through which no other bids were received, [Retail Gas Utility] shall re-issue an RFP to the broadest practical set of eligible Capacity Service Providers in order to obtain competitive capacity service bids for the capacity service contract proposed to be awarded to an affiliate of [Retail Gas Utility].
7. In the event a capacity service contract is awarded to an affiliate of [Retail Gas Utility] for a capacity path between a supply receipt area and a delivery area along or through which [Retail Gas Utility] also received bids for and/or awarded capacity service contract(s) to

⁴⁵ M.J. Bradley & Associates, New York Gas Company Climate Planning Tool and New York Gas Planning Greenhouse Gas Framework (May 2021), https://mjbradley.com/mjb_form/Gas-tools.

non-affiliated Capacity Service Providers, the [Retail Gas Utility] shall maintain contemporaneous documentation showing that the price established under the contract awarded the affiliate was within or lower than the range of prices established under contracts awarded to entities other than the affiliate.

8. If the affiliate's bid price or contract price does not meet the criteria in paragraphs 5, 6 or 7, [Retail Gas Utility] may not award the capacity service contract to the affiliate, unless the [Retail Gas Utility] can demonstrate and contemporaneously document that a more favorable bid was rejected for legitimate reasons relating to the rejected bidder or bidders' creditworthiness, performance history (or lack thereof), or other consideration bearing on the fitness and reliability of the bidder to provide the requested service.
9. In the interests of optimizing the competitive benefits of the RFP process, the RFP will explicitly inform potential bidders that [Retail Gas Utility] permits Capacity Service Providers to propose alternative ways of satisfying the ultimate need, including but not limited to basic quantity, reliability, receipt, delivery and pricing terms of the RFP in addition to those specifically contemplated by the RFP. The RFP may also utilize ranges for such quantity, reliability, receipt, delivery, pricing and/or other terms.

This type of proposed framework has numerous benefits. It will bring enhanced clarity and transparency to available supply and demand alternatives, spur innovative solutions to facilitate the objectives of the state's climate goals, and assist the Board, Staff, GDCs, and interested stakeholders in making informed decisions in shaping the future energy system. As noted above, other jurisdictions employ a similar framework, and this type of before-the-fact review of any interstate capacity contracts would also assist the Federal Energy Regulatory Commission in its decision-making at the federal level.⁴⁶ This thorough, upfront review will allow the Board to protect against a situation where FERC approves an unnecessary project and the Board is left with limited retroactive regulatory tools to assess prudence.⁴⁷

⁴⁶ See Preliminary Determination on Non-Environmental Issues, *Ruby Pipeline, L.L.C.*, 128 FERC ¶ 61,224 at P 37 (Sept. 4, 2009) (finding the proposed Ruby pipeline and transportation contract "consistent with Commission policy" in part because the California Public Utilities Commission "directed PG&E to replace expiring contracts on GTN in order to diversify PG&E's gas supply, and, after evaluating several options, the CPUC approved PG&E's acquisition of capacity on Ruby's proposed pipeline").

⁴⁷ Under the Narragansett doctrine, "state regulatory commissions, in setting retail rates, must allow recovery of the interstate wholesale utility rates that have been made effective by [FERC] in the exercise of its exclusive jurisdiction over the regulation of such rates." Andrea J. Ercolano & Peter C.

4. Heightened Review of Affiliate Transactions

One important benefit of the above framework is that it allows for a transparent evaluation of both affiliate and non-affiliate alternatives. The framework provides that, in the event a contract is awarded to an affiliate, the gas utility must maintain contemporaneous documentation showing that the affiliate's bid price was equal to or lower than the bids received from non-affiliated suppliers. This provision will ensure that customers will be protected against any unnecessary costs resulting from an affiliate-backed transaction.

Applying heightened scrutiny to affiliate transactions at the state level is critical because there are no such protections in place at the federal level that govern newly formed affiliate pipeline developers. The standards of conduct adopted in FERC Order 717 apply to existing interstate natural gas pipelines.⁴⁸ A newly formed affiliate pipeline developer becomes a natural gas company, as defined by section 2(6) of the Natural Gas Act and subject to FERC jurisdiction, “[u]pon the receipt of its requested certificate authorizations and commencement of pipeline operations.”⁴⁹ However, during the pivotal period of the open season process and contract negotiation, there are no rules in place governing the interactions between a newly formed pipeline developer and its affiliate gas utility. In practice, this means there is no meaningful separation between the pipeline development personnel and gas supply and operations personnel and that major new infrastructure projects are proposed and designed as the result of “negotiations” within the same corporate family and primarily for the benefit of that same corporate family's shareholders.

Lesch, *Narragansett Update: From Washington Gas Light to Nantahala*, 7 Energy L.J. 333, 333 (1986).

⁴⁸ 18 C.F.R. § 358.1.

⁴⁹ *Spire STL Pipeline LLC*, 164 FERC ¶ 61,085 at P 3 (2018); *see id.* at P 104 (summarizing Spire's argument that it is not yet a “transmission service provider” and therefore not subject to the Commission's Order No. 717, *Standards of Conduct for Transmission Providers*).

FERC’s primary concern regarding affiliates in certificate proceedings is whether there may have been undue discrimination against a non-affiliate shipper.⁵⁰ This concern completely ignores the threat of affiliate abuse posed when a newly formed pipeline developer enters into a negotiation with its affiliated gas utility and uses that precedent agreement to justify need for a major infrastructure project. Further compounding the problem is the Board’s current position that it will not initiate review of such projects before they are built:

“In New Jersey, regulators do not require pre-approval of precedent agreements by LDCs. There is no regulatory role until after a pipeline is built and LDCs seek cost recovery for transportation contracts from the NJ Board of Public Utilities. Such an outcome would result in a long-term glut in capacity that state regulators have no ability to remedy, and constitutes a significant regulatory gap.”⁵¹

The consequence of this regulatory framework is that stakeholders are left with only one tool to challenge these types of projects before the state: after-the-fact prudence reviews. Ironically, FERC has described such processes as “lengthy, resource-consuming and uncertain in their outcome.”⁵²

The threat of affiliate abuse in New Jersey is not merely abstract. Stakeholders have been questioning the need for the affiliate-backed PennEast project for years.⁵³ When EDF attempted to raise concerns regarding this project in several of the GDCs’ BGSS dockets, the Board denied EDF’s intervention, stating:

⁵⁰ *Id.* at P 45.

⁵¹ Request for Rehearing and Motion for Stay on Behalf of New Jersey Conservation Foundation and Stony Brook-Millstone Watershed Association, FERC Docket Nos. CP15-558, at 43-44 (February 12, 2018).

⁵² *Cove Point LNG Ltd. P’ship*, 68 FERC ¶ 61,128, 61,619 (1994).

⁵³ Lander, Greg, “Analysis of Public Benefit Regarding PennEast Pipeline” at 11 (March 9, 2016), available at: <https://rethinkenergynj.org/wpcontent/uploads/2016/03/PennEastNotNeeded.pdf> (estimating that the financial burden created by the glut of capacity the PennEast Project would introduce is estimated at \$180 million to \$280 million per year on just two legacy pipelines).

“NJNG ... is not seeking any costs related to the PennEast Agreement in this proceeding. Therefore, a review of the PennEast Agreement is not likely to add to a determination on the how NJNG's purchasing strategies affect NJNG's BGSS costs in this proceeding.”⁵⁴

As these examples demonstrate, the Board is in need of updated tools to address the threat posed by affiliate contracts and should therefore adopt the framework above.

5. Standard Method for Assessing GHG Emissions

Incomplete or insufficiently transparent planning can lead to adverse consequences, including increases in GHG emissions, and contravene the GWRA. Calculating and reporting greenhouse gas emissions associated with all solutions, both supply-side and demand-side, is necessary for transparency when weighing competing alternatives. The Gas Company Climate Planning Tool, developed by M.J. Bradley & Associates, can be used to assess the lifecycle GHG emissions of gas utilities.⁵⁵ The tool can be used to evaluate different portfolios of gas supply options against each other, to compare specific discrete options against each other, or to evaluate the effect of a proposed portfolio on state-wide GHG reduction goals. The Gas Company Climate Planning Tool consists of a life cycle approach that accounts for GHGs emitted throughout the entire value chain of natural gas and other fuels, from production all the way through end use⁵⁶ and is based on the following six core principles:

1. Account for all combustion-related GHG emissions and fugitive methane emissions.
2. Account for both supply- and demand-side options to manage and meet gas demand.
3. Use the most recent, publicly available data.
4. Identify and incorporate significant uncertainties.

⁵⁴ *In the Matter of the Petition of New Jersey Natural Gas Company for the Annual Review and Revision of its Basic Gas Supply Service (BGSS) and Conservation Incentive Program (CIP) Rates for F/Y 2020*, DECISION AND ORDER APPROVING STIPULATION FOR PROVISIONAL BGSS AND GIP RATES (September 11, 2019). Similar language was in the orders for the other two gas company BGSS cases denying EDF’s intervention in those cases.

⁵⁵ M.J. Bradley & Associates, *New York Gas Company Climate Planning Tool and New York Gas Planning Greenhouse Gas Framework* (May 2021), https://mjbradley.com/mjb_form/Gas-tools.

⁵⁶ *Id.* at page 4.

5. Align the analysis with economy-wide GHG emission reduction targets under state climate laws.
6. Monetize life cycle GHGs using the Social Cost of Carbon Dioxide, the Social Cost of Methane, and the Social Cost of Nitrous Oxide.⁵⁷

The figure below demonstrates a sample results table generated by the tool:



To ensure an accurate assessment of the GHG emissions impact of a given course of action, the Board should build into the planning process requirements that GDCs must use a common methodology to calculate the GHG emissions associated with a proposed project, and to project their overall GHG emissions out to 2050.

⁵⁷ *Id.*

6. Joint Gas-Electric Planning Assessments

As the Board takes steps to update its gas planning framework, it must ensure that the planning framework is durable enough to accommodate the significant changes on the horizon. As New Jersey pursues its climate targets, infrastructure once deemed to be used and useful may no longer be needed—and that transition will accelerate over the next decade as the State deploys its electrification plans and programs. To prepare for this future, the Board should require a Joint Feasibility Assessment to be conducted by both gas and electric utilities to identify the challenges, opportunities, and barriers to high electrification scenarios.

Other states are conducting similar types of analyses to inform how gas utility operations will need to evolve in light of rigorous climate goals. For example, in Massachusetts, the gas utilities are evaluating both high electrification and low electrification scenarios. The high electrification scenario assumes a significant reduction in Local Distribution Company (“LDC”) sales and requires the LDC to conduct a feasibility and impact assessment:

Building on the 2030 CECP Examination, perform a detailed examination of the feasibility and impact on customers and the LDCs’ gas distribution operations through 2050, assuming a pace of building services electrification and required emissions reductions as described in the 2050 Roadmap All Options scenario resulting in an approximately 90% volumetric reduction in total LDC sales.⁵⁸

The Joint Feasibility Assessment should consider hard-to-electrify buildings and industrial applications that are the most likely to continue relying on gas molecules instead of electrification, and conversely should consider the low-hanging fruit areas for electrification. Most critically, the analysis should be conducted in coordination with the corresponding electric utility (or utilities) operating in the gas utility’s service territory. For combined gas and electric utilities, this coordination would occur more naturally. Gas-only utilities may need to institute

⁵⁸ Massachusetts Dept. of Pub. Utilities, Request for Proposal: The Role of Gas Distribution Companies in Achieving the Commonwealth’s 2050 Climate Goals at p7 (Feb. 5, 2021), <https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/13209897>.

more formal channels of communication between the gas utility and electric utility counterpart to coordinate respective capabilities and plans.

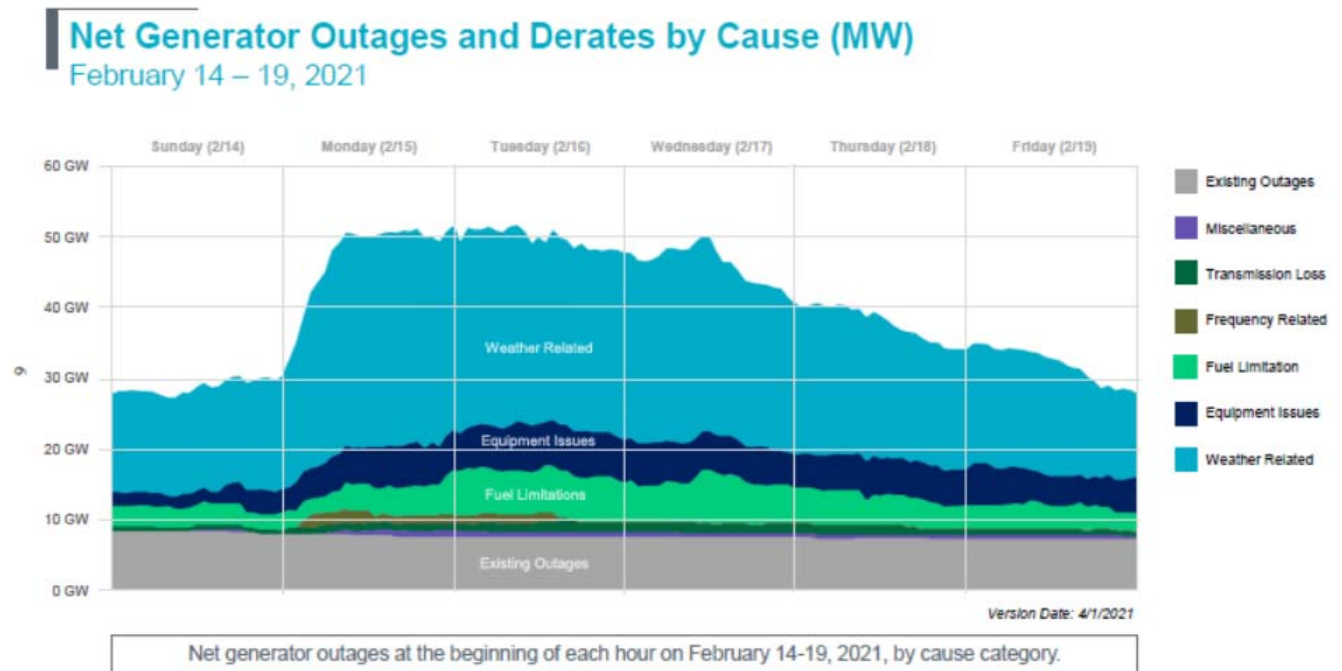
This type of thoughtful and deliberate planning can help save costs for both utilities and ratepayers, for example through strategic targeting of electrification efforts. “[I]f electrification occurs on a house-by-house basis, both gas pipelines and electricity lines in a neighborhood will be maintained and benefits from electrification could take longer to manifest. The state could therefore miss critical opportunities for market and grid transformation. There may be better bang for the buck to push to electrify entire blocks or subdivisions, both from a marketing perspective and from deployment of grid infrastructure.”⁵⁹ By requiring a Joint Feasibility Assessment early in the energy transition, the Board can provide greater regulatory certainty to both gas and electric utilities, accelerate the adoption of clean energy technologies, and reduce costs to customers associated with an unmanaged transition.

D. The Texas Reliability Crisis Should Not Be Used as a Justification for Action in this Proceeding

During the public meeting, several stakeholders referred to the February event in Texas to express blanket concerns about reliability in New Jersey and potential risks associated with a “Texas-like” event. The Board should take note of the underlying causes of the Texas event—and the stark differences between that region of the country and the Northeast. Insufficient weatherization affected multiple types of generation during the Texas event. Insufficient weatherization also affected gas production, gathering and processing and thus the total quantity of available gas supply. Between gas supply and un-weatherized generation units, the biggest loss in capacity was among natural gas-fired generators, with approximately 25 GW unavailable

⁵⁹ EDF, *Managing the Transition: Proactive Solutions for Stranded Gas Asset Risk in California* at p25 (2019), https://www.edf.org/sites/default/files/documents/Managing_the_Transition_new.pdf.

for the two peak days of the event.⁶⁰ Weather and equipment related issues were the primary cause of the outages:



Unlike Texas which experiences extreme cold temperatures quite infrequently, the Northeast’s gas production and electricity production facilities experience extreme cold frequently, and are substantially and appropriately weatherized. The Northeast has effectively managed reliability through polar vortices and bomb cyclones. While there may be gas pipeline capacity constraints in pockets of the Northeast, the region is not plagued by frozen gas-production lines, frozen blades on wind-turbines, or gas-fired generators freezing because they are not ready for winter’s cold. Given these important distinctions, the Board should carefully weigh any claims regarding the potential risks in New Jersey associated with a “Texas-like” event.

⁶⁰ ERCOT, Review of February 2021 Extreme Cold Weather Event at page 13 (February 24, 2021), http://www.ercot.com/content/wcm/key_documents_lists/225373/Urgent_Board_of_Directors_Meeting_2-24-2021.pdf.

E. Comments in Response to Specific Questions Posed in the Public Notice

1. Should New Jersey be moving towards common design day reliability criteria?

Yes, the Board should establish a 1 day in 30 year (“1-in-30”) Design Day as the weather that drives the demand for which the GDCs plan. While the weighting of the temperature values from the weather stations in or proximate to each of New Jersey GDCs’ service territories may vary, having the same 1-in-30 standard based on the same 1-in-30 day is recommended.

2. Are there reasons for allowing different GDCs to utilize different design day reliability criteria?

No, the Board should apply a uniform common “design day” and “design hour” to answering the question of “what” is the weather condition that should drive GDC design planning. Once the metric for “what” should be planned for is established, the GDC would present a specific outline of “how” it plans to meet that “design day” and “design hour.”

3. How does the selection of higher or lower design day reliability criteria affect the issue of whether, in your view, there are sufficient gas resources into New Jersey to maintain system reliability?

Once the “what” is identified (i.e., the design day and design hour to be planned for), the issue of higher or lower reliability criteria is addressed.

4. Please discuss the costs and the benefits associated with using a 1-in-90 year design basis day versus a 1-in-30 year design basis day, with a focus on impacts to system reliability, customer affordability, and any other tradeoffs.

Extreme temperature data indicatively shows that the 30-year criteria is relevant and sufficient. Three locales’ airports were reviewed below—Newark (EWR), Philadelphia (PHL), and Allentown (ABE). From the data reviewed, the (1) lowest recorded temperature in the past 30 years and year of observance for each locale and (2) the record lowest temperature for each

locale over the period of the load duration curves and year of record observance are set forth below:

Locale	Lowest Recorded Daily Average Temp Last 30 Yrs	Year Month and Day of Lowest Temp	Lowest Recorded Temp of Load Duration Curve period	Year and Month of Observation during Load Duration Curve Period
Newark	-2	Jan 19, 1994	0	Feb 2016
Philadelphia	-5	Jan 19, 1994	4	Jan 2018
Allentown	-11	Jan 19, 1994	-8	Feb 2015

Below are the highest demand days for each of the load duration curves and the average Gas Day Temperature for each of the 3 locales.

Highest Demand day of each of the 5 Load duration curves	NJ Scheduled Qty	Newark Avg Temperature	Philadelphia Temperature	Allentown Temperature
Feb 15, 2015	4,869,327	10	10	6
Feb 13, 2016	5,506,327	13	17	12
Dec 15, 2016	5,172,532	21	21	18
Jan 1, 2018	5,359,726	15	16	12
Jan 31, 2019	5,657,207	11	14	5

Below is the New Jersey Demand on each of the record lowest temperature days during the Load Duration curve period.

Date	Locale	Lowest Load Duration Curve Temperature	NJ Scheduled Qty
Feb 14, 2016	Newark	0	5,472,628
Jan 7, 2018	Philly	4	5,251,314
Feb 24, 2015	Allentown	-8	4,474,410

From the indicative 1-in-30 year data identified in advance of the April 29, 2021 Stakeholder Meeting and the actual data provided with respect to the load duration curve periods,⁶¹ it is clear that more gas was delivered to New Jersey demand locations, in total, than LAI identified as New Jersey GDC capacity. It is also clear that the highest demand days for each of the five load duration curves had demand that was greater than the coldest winter day during the load duration curve period at each of the three locales.

Finally, assuming the LAI-asserted level of GDC pipeline capacity is sufficient to meet their respective design days, and given actual deliveries under all pipeline contracts (including GDC and others) exceeded LAI levels by from 0.5 BCFd to 1.5 BCFd and based upon Mr. Lander's analysis that available (and likely unsecured) capacity could facilitate an additional 1.2 BCFd or greater deliveries beyond historic actuals, moving to the 1-in-30 standard has little prospect of leading the GDCs to either over- or underestimate firm demand. Rather, such a standard will bring consistency to the objective design day (and hour), allowing the BPU Staff to focus on the "factors" the GDCs use to convert from temperature to load for each of its GDC's rate classes.

5. How have voluntary peak management demand programs been structured in other jurisdictions or related industries? For example, how much would it cost to purchase and install directly controllable thermostats for all firm heating customers? Would smart meters be required as well? What would be the cost of these? Are there other examples of peak management demand programs, and what best practices can the State implement for these programs?

Issues of peak management demand programs may or may not need to be considered once the GDCs plan for a common design day and design hour. Should there be identified

⁶¹ See chart provided in EDF comments of EDF/NJCF dated October 21, 2019.

current or future firm demand in excess of secured capacity, cost and benefit comparisons can be made to identify how best to meet (and/or reduce) the identified demand.

6. Consider a program in which smart thermostats controlled directly by the GDC during potential supply disruption were provided to all firm heating customers at no cost to the customer, and the capital cost to the GDC could be included in rate base. Please describe the benefits and consequences of such a program. How should Staff consider the program in terms of cost to provide reliability? Would it be equitable to all customers?

Issues related to the efficacy or requirement for “smart thermostats” may or may not need to be considered once the GDCs plan for a common design day and design hour. Should there be identified current or future firm demand in excess of secured capacity, cost and benefit comparisons can be made to identify how best to meet (and/or reduce) the identified demand.

7. What would be the potential uptake and impact of a “time of use” (TOU) program? For example, if a TOU or other peak demand-management program was offered to customers based on smart thermostats, would an opt-out program have a bigger impact than an opt-in program? If so, what would be the magnitude? Would it be more effective to offer an option to customers to opt in or opt out based on a level of emergency (e.g., yellow, orange, or red) where there would be different price incentives based on the level of the emergency?

TOU is not a price-based approach currently available to the gas business. TOU is only a demand response tool that would be part of the design hour planning and DR/EE implementation. In addition, issues related to the efficacy or utility of one or more TOU programs may or may not need to be considered once the GDCs plan for a common design day and design hour. Should there be identified current or future firm demand in excess of secured capacity, cost and benefit comparisons can be made to identify how best to meet (and/or reduce) the identified demand.

8. How would the impact of TOU pricing affect a firm heating customer's monthly bill in the winter? What are the ways that this could be mitigated without dampening the incentive to conserve? For example, should peak prices be tied not to the wholesale price of natural gas, which can be extremely volatile, but rather be set as an adder to existing BGSS prices, with the adder tied to projected day-ahead sendout? Should such prices be capped?

See response to Question 7 above.

9. What are the limits to the efficacy of peak demand reduction programs?

See responses to Questions 5 and 6 above.

10. What are the pros and cons of relying on government emergency orders to cope with a potential emergency (for example, orders shutting down businesses), rather than having peak demand programs in place?

See response to Question 3 above. In addition, future government emergency orders, their threshold, extent, and public acceptance (i.e., effectiveness) may well: 1) be different in response to similar events, 2) lack speed of event recognition sufficient to address emergency, 3) face resistance by, or inability of, businesses to safely respond (ex. water line freezes, boiler freezes, shelf product loss, loss of animal life etc.). Conversely, demand response programs with implementation plans, contracts, and carrots and sticks do not suffer the same 'government emergency order' shortcomings. That is not to say that one or more government emergency orders in response to a gas system emergency which exceeds the programs' abilities to cope should be avoided or go unused; it is just that organized programs that address all but the most rare and severe of events will make government emergency orders the exception and not a rule likely to have less positive impact with successive uses. Lastly, once the government issues emergency orders, it becomes the government's responsibility as opposed to the GDCs responsibility to plan reasonably to avoid the problem occurring in the first place.

10. Are there other measures the Board should consider to ensure the reliability of the natural gas system?

As discussed above, the Board should initiate a new proceeding to establish a Gas Planning Process whereby each GDC files plans identifying future demands, and how they plan to address those demands while meeting the state's climate goals.

III. Conclusion

The Board has the opportunity in this proceeding to align gas utility planning and operations with New Jersey climate law and policy and give meaning to the GDCs' obligation to serve in a manner that preserves and conserves the quality of the environment. Adopting the recommendations set forth above will allow for a comprehensive planning framework that meets today's needs and is durable enough to accommodate forthcoming state climate policies. EDF and NJCF look forward to continuing to engage with the Board, BPU Staff, GDCs and other stakeholders to ensure that gas utility planning is aligned with climate policy.

Dated: May 13, 2021

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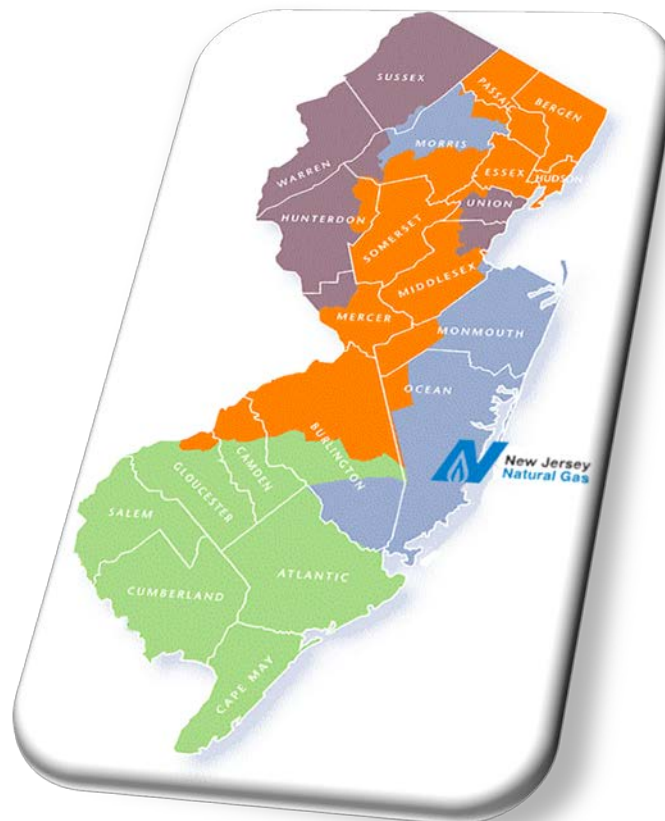
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EXHIBIT B

Skipping Stone, Analysis of the Southern Reliability Link
as a Response to Single Point of Failure Concern
(June 28, 2017)

Analysis of the Southern Reliability Link as a Response to Single Point of Failure Concern



Author: Greg Lander

For

The Pinelands Preservation Alliance



www.skippingstone.com

June 28, 2017

About Skipping Stone

Skipping Stone is an energy markets consulting firm that helps clients navigate market changes, capitalize on opportunities and manage business risks. Our services include market assessment, strategy development, strategy implementation, managed business services and talent management. Market sector focus areas are natural gas and power markets, renewable energy, demand response, energy technology and energy management. Skipping Stone's model of deploying only energy industry veterans has delivered measurable bottom-line results for over 270 clients globally.

Skipping Stone operates Capacity Center which is a proprietary technology platform and data center that is the only all-in-one Capacity Release and Operational Notice information source synced with the Interstate pipeline system. Our database not only collects the data as it occurs, it is a storehouse of historical Capacity Release transactions since 1994. We also track shipper entity status and the pipeline receipt and/or delivery points, flows and capacity. Our analysts and consultants have years of experience working in natural gas markets. Capacity Center has worked with over a hundred clients on a wide variety of natural gas market and pipeline related reports and projects.

Headquartered in Boston, the firm has offices in Atlanta, Houston, Los Angeles, Tokyo and London. For more information, visit www.SkippingStone.com.

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Executive Summary

Abstract

In this report, Skipping Stone analyzes the justification for the Southern Reliability Link (SRL) provided by the New Jersey Board of Public Utilities, namely a need for reliability in the event of a disruption of the Texas Eastern Transmission Company (“TETCO”) pipeline, the primary pipeline supplying gas to NJNG’s network. Our analysis shows that SRL is not an effective or reasonable response to a single point of failure scenario and that a less costly and less disruptive alternative exists to address a possible interruption on TETCO. The analysis also shows that SRL does not, in fact, provide an adequate remedy, and would leave NJNG with 66% of its requirements unmet.

This analysis demonstrates that there is only one genuine, though remote, Single Point of Failure scenario for the TETCO supply to NJNG’s system, based on a failure along a recently built 12-mile lateral line. Skipping Stone was unable to construct any scenario involving a major disruption of the TETCO mainline at a single point for which a facility of the magnitude of SRL would be an efficacious, reasonable or cost-effective response.

To address the only genuine risk on the TETCO system, Skipping Stone identified a viable alternative to SRL that would cost less than 20% of the cost of SRL and pose minimal local impacts, without traversing the protected region of the Pinelands. This analysis concludes that SRL is an unneeded and flawed project.

The documents in the Board of Public Utilities (BPU) proceeding on SRL include no analysis of SRL’s ability to mitigate the risk of disruption should a failure occur on TETCO. In the event of a failure at the only point on the entire TETCO system that would pose a serious risk to NJNG, SRL provides a poor solution, as it would still leave NJNG with 66% of its requirements unmet. In contrast, the alternative recommended in this report would enable NJNG to meet 100% of its requirements at 20% of the cost.

BPU did not even consider, and NJNG did not analyze, alternative means of addressing this specific, if highly remote, failure scenario.

Background on SRL

The Southern Reliability Link (SRL) is a 30-mile natural gas pipeline, proposed by New Jersey Natural Gas (NJNG) that would cost more than \$178 million to construct. NJNG promotes it as a second pipeline feeding the southern end of its territory that would enhance the reliability of the service provided to customers.

The project was approved by the New Jersey BPU in 2017 based on the stated rationale that it would provide greater reliability to NJNG’s customers in the event of a major interruption on TETCO, the primary pipeline supplying gas to NJNG’s network. In its approval, BPU explained that SRL would address the situation in which a major failure on TETCO, at a single point, would make NJNG unable to get a majority of its supplies from TETCO. If built, SRL would enable NJNG to get a portion of that supply at a new interconnection with Transco, a pipeline that is already a second source for NJNG.

BPU’s approvals of SRL relied entirely on the premise that SRL is reasonably necessary to serve the public because it would avoid major disruptions due to a Single Point of Failure in the TETCO supply to NJNG.

Reliability Analysis

Neither NJNG nor the Board of Public Utilities provided details or an analysis of the hypothetical single point of failure that could plausibly occur and result in NJNG becoming unable to get a majority of its supplies from TETCO.

Skipping Stone was asked to 1) determine whether there exists a specific single point of failure that could produce such consequences and 2) to evaluate whether SRL is a reasonable response to such a risk.

Zero risk of disruption on TETCO mainline

There is no point along the TETCO mainline pipeline system, 9,096 miles long, that would meet the risk of a 50% or greater supply loss, which is BPU's definition of what constitutes a disruption. In the event of a complete failure at any point along the TETCO mainline, Skipping Stone's analysis showed that NJNG would still be able to receive between 96% and 100% of its contracted supplies because of the high level of reliability that already exists in the TETCO supply system due to its bidirectional flow characteristics near the NJNG interconnect with TETCO.

Analysis of the worst-case failure of the TETCO mainline, the complete loss of one TETCO pipeline to the southwest of its connection to NJNG's network, found that re-routing supplies and taking advantage of underutilized capacity would replace all disrupted capacity. With the loss of a pipeline, NJNG would continue to receive 96% of its contracted amount on TETCO. In addition, underutilized capacity on the Transco system could supply at least 0.138 Bcf/d of additional capacity to NJNG, an amount far in excess of the 0.023 Bcf/d lost by the failure. The BPU's findings regarding NJNG's available capacity on Transco supports this conclusion.

TETCO mainline has become highly reliable

Historically, TETCO's supply sources were located in Texas and the Gulf Coast and brought to the Northeast throughout the year. This analysis shows that the historic pattern has changed and that TETCO is no longer a uni-directional system that previously would have been vulnerable to a major disruption. Almost two-thirds of peak supplies now enter the system near the NJNG service area, coming from new shale gas sources in Pennsylvania. Analysis of recent pipeline flow data that covers three peak winter seasons, shows that TETCO has become a bi-directional pipeline that, with respect to NJNG's interconnect location, now flows to the northeast during peak periods and to the southwest for much of the year.

The result of a bi-directional pipeline, in a region well supplied by other interstate pipelines, is that the system itself has become highly reliable, and can compensate for major disruptions with no loss of service.

Alternative provides zero risk of disruption at any TETCO point

Skipping Stone found only one section of the entire TETCO network across which a major failure would substantially disrupt supplies to NJNG: a 12-mile stretch known as the Freehold Lateral. While a failure in the Freehold Lateral has the potential to disrupt a majority of NJNG supplies, SRL is not a solution, because it would not provide sufficient replacement volume to NJNG and is both far more costly and disruptive than the alternative, right-sized solution identified here.

The Freehold Lateral connects the TETCO mainline to the NJNG service area. A failure along this stretch is unlikely, as this section was constructed only 15 years ago. Nevertheless, we examined options to mitigate a failure in the Freehold Lateral and identified an alternative approach that we named the Freehold Backup. The potential for disruption using the Freehold Backup alternative is near zero percent. The possible supply loss level for this alternative is well below the 50% level set by the BPU as justification for the SRL.

The Freehold Backup alternative relies on re-routing through Transco, the second major pipeline system serving NJNG. This analysis shows that the combination of providing a new 5-mile backup pipe together with re-routing to use existing pipeline capacity could provide sufficient flexibility to meet all NJNG contracted supply in the event of failure. If, however, existing TETCO-Transco interconnects are insufficient to satisfy 100% of contracted

amounts, NJNG could access additional supplies directly from Transco. Additional deliveries at the existing Transco-NJNG interconnects would fully eliminate any potential shortfall that would occur in re-routing supplies. Our analysis shows that at least 0.138 Bcfd of additional capacity can be obtained from Transco. Actual pipeline flow data from the winter of 2016 shows that NJNG was able to receive supplies from Transco far in excess of its existing contracts. This flow data demonstrates that NJNG can receive at least 0.138 Bcfd of gas supplies from Transco, as it did in the winter of 2016.

The proposed alternative Freehold Backup would require a new 5.4 mile, 24" pipeline, co-located near the existing Freehold Lateral and two new interconnects that would enable the Transco system to provide supplies into the NJNG system.

There is no evidence in the public record that BPU evaluated the operations of the TETCO pipeline system or considered any alternatives to SRL. It appears that BPU misunderstood the way the TETCO supply actually functions. Had the BPU understood the bi-directional nature of the TETCO mainline supply, it would have found that SRL is neither financially prudent nor the least disruptive means of addressing the risk of gas supply interruption. This analysis demonstrates that an alternative to SRL exists which is far less expensive, has a reduced impact on affected communities, and completely avoids the preserved Pinelands area.

With the cost of building SRL at nearly \$180 million, the Freehold Backup alternative at about \$26 to \$28 million is vastly less expensive and would save NJNG ratepayers more than \$150 million in construction costs.

Skipping Stone evaluated every scenario involving failures of the Freehold Lateral at various locations and concludes that for every scenario, the new Freehold Backup could satisfy 100% of NJNG's peak requirement of 0.57 Bcfd.

Introduction

In this Report, entitled: “Analysis of Southern Reliability Link as a Response to Single Point of Failure Concern,” Skipping Stone was asked by the Pinelands Preservation Alliance (“PPA”) to review documents and publicly available information to ascertain all of the following:

- 1) What, if any, single point of failure impacting the New Jersey Natural Gas Company (“NJNG”) would necessitate the creation of the Southern Reliability Link (“SRL”) to address the circumstance(s) of a single point of failure as characterized by the New Jersey Board of Public Utilities (“BPU”) as justification in its Order approving the SRL?
- 2) What failures of line or compression with respect to the major interstate pipeline (i.e., Texas Eastern Transmission Company - “TETCO”) serving NJNG could occur that would (or could) affect NJNG’s ability to get a majority (i.e., 50% or greater) of its supplies from TETCO?
- 3) What magnitude of disruption of TETCO would necessitate a facility on the scale of the SRL in order to address said failure?
- 4) Identify a worst case but possible failure of TETCO, and where such failure would have to occur to make the SRL facility a required facility to maintain gas service.
- 5) What alternative(s) (i.e., an “Alternative Single Point of Failure Redundancy Solution”) to the SRL back-up/redundancy facility could be built (if any) at less cost and/or environmental disruption to address such worst-case failure of a TETCO facility?
- 6) With regard to the natural gas load of the Joint Base:
 - a. What is the magnitude of the Joint Base gas demand and load? and finally,
 - b. Given this Joint Base load, is there any contribution to reliability of service for that load that can only be addressed by the SRL and not by any other Alternative Single Point of Failure Redundancy Solution?

Background

The SRL proposal by NJNG was filed before the BPU in 2015.¹ In its proposal, NJNG stated that the SRL was not intended to serve new load, but rather was intended to provide additional reliability of service to its service areas on the southern end of its service territory.

During the post-hearing briefing stage of that proceeding, the PPA asked Skipping Stone to review filings in that proceeding and determine: 1) what if any failure of NJNG’s backbone mainline system serving the coastal region of NJNG might be susceptible to disruption from a natural disaster; 2) what added resiliency the SRL might provide to those areas if built; and, 3) what alternatives to the building of the SRL might address such disruptions.

Skipping Stone has reviewed its earlier report memorandum and continues to support its conclusions drawn in that report.

¹ Initial NJNG BPU filing was April 2, 2015 and the Amended filing was on June 5, 2015

Prior Skipping Stone Report Conclusions

In this earlier report Skipping Stone concluded:

- 1) that the NJNG system north of the commencement of its single line system serving its southernmost areas was sufficiently resilient that it could continue to support service in the south without the addition of the SRL;
- 2) that the closest backbone line to the coast was adjacent to the Garden State Parkway (4.3 miles inland at its closest and buried below ground by at least 4 feet²); and
- 3) that no segment of its northern most system posed a reasonably discernible “single point of failure risk” to maintaining service to its southernmost service area.

Procedurally, PPA was not granted full intervenor status by the BPU and thus, while the PPA submitted the memorandum, the BPU appears to have relied on PPA’s lack of the technical intervenor status in that proceeding to not consider the memorandum evidence in its Order.

BPU Standard of Decision

The BPU, after looking at all the evidence admitted into the proceeding, decided to approve the SRL, resting the weight of its decision on its finding that the SRL would enable NJNG to mitigate a service disruption resulting from a single point of failure³ on the TETCO supply pipeline. The BPU defined a ‘failure’ as one involving a 50% loss of supply to NJNG.⁴

In its analysis for this report, Skipping Stone refers to and utilizes this BPU established standard for justification of the SRL when Skipping Stone examined alternatives to avoid the consequences to NJNG and its customers from experiencing a “Single Point of Failure” (i.e., the 50% reduction in supply from TETCO to NJNG).

With respect to the “need” for the SRL, the BPU cited NJNG’s representations that “The Project is exclusively a reliability project, meant to provide an alternate interstate transmission feed for customers, and is not designed to service new or additional load. Exhibit P-1A 9:2-4.”⁵

The BPU also stated that TETCO currently provides 85% of NJNG’s peak day natural gas requirements.⁶

² In addition, Skipping Stone determined that the type of natural disaster sufficient to disrupt such a facility would have wiped out the service area (and thereby eliminated the load of the service area) that such NJNG facility would otherwise serve. In short, as detailed in the memorandum “one has to envision an event of weather sufficiently violent to the point of causing failure of a pipeline lying 4.3 miles inland and which, at that inland location, rests 4-6 feet underground. In this regard, were this to occur, the more southerly coastal demand that NJNG serves with this one of three north-to-south lines would largely be decimated if not permanently destroyed from an event able to disturb the noted segment to the point of failure.

³ The BPU states in its Order “The current TETCO interconnection, at the northern end of NJNG’s transmission system servicing the Counties, essentially equates to a single point of failure.”

⁴ At page 13 of the March 16, 2016 Order the BPU states: “In the event of a fifty (50) percent reduction of supply from TETCO, which exceeds the capacity provided by a twenty-four (24) inch pipeline, the design of SRL [a 30” line] would ensure transmission system integrity.”

⁵ Exhibit P-1A 9:2-4. Refers to the testimony of Mr. Lynch of NJNG.

⁶ In the Order the BPU states as to Mr. Lynch (of NJNG)’s Testimony: “TETCO deliveries to NJNG’s city gate in Middlesex County comprise over eighty-five (85) percent of the winter season peak day gas supply and, because of this, customers at

Pertinent Facts Relating to Assessing Single Point of Failure as it Relates to TETCO Service to NJNG

To assess the SRL “solution” to the problem statement as framed by the BPU with respect to the 6 questions outlined above, it is important to first understand:

- 1) The physical configuration of the TETCO system,
- 2) Its historic flow patterns (i.e., pre-shale revolution), and,
- 3) Its flow patterns in existence today and prior to NJNG’s proposal for the SRL in 2015.

Historic TETCO System Flow Configuration

Historically TETCO’s predominant supply sources were in Texas and the Gulf Coast and its flow was predominantly from Texas and the Gulf Coast to the Northeast. In addition, TETCO had and continues to have substantial storage assets in Southwestern Pennsylvania that also historically flowed gas to the Northeast during winter periods. We define the area of interest in this report as the “NJNG Area.” The NJNG Area subject to analysis in this report takes supplies from the TETCO pipeline to serve its customers in Somerset, Middlesex, Monmouth, and Ocean Counties. NJNG’s service territory resides at the very northern end of the TETCO system, which terminates in New York City, and is connected beyond to pipelines taking gas to customers in the Northeast and New England.

Thus, historically, from the perspective of the pertinent NJNG Area, everything west and south of where this area received gas from TETCO was considered upstream or towards the origin of flow. Further, from the TETCO storage fields in Southwest PA to TETCO’s terminus in New York City, TETCO historically was a uni-directional flow system with a distinctive and predominant upstream to downstream flow pattern that relied on supplies coming from the west and south to reach their load centers.

The map that follows shows TETCO, the other interstate pipelines, the contiguous NJNG service territory (the “NJNG Area”), and the proposed route of the SRL.

the southern end of the NJNG system in Ocean, Burlington, and southern Monmouth Counties are particularly vulnerable to a supply interruption or system failure in the interstate pipelines, the gate station, or NJNG’s upstream transmission backbone system. Exhibit P-1A 8:7-16.”

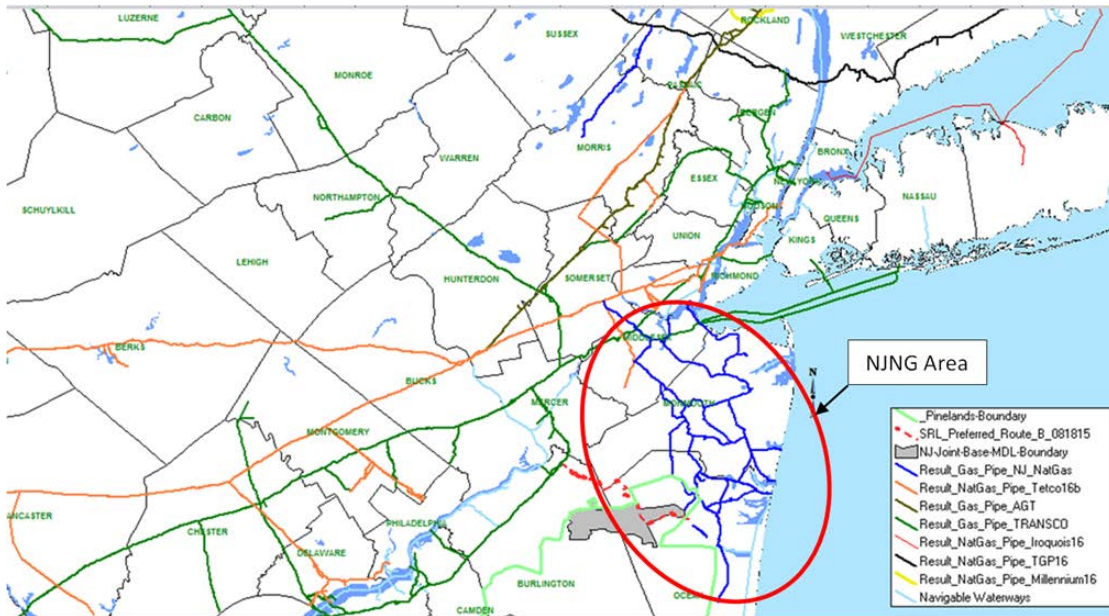


Figure 1 – Interstate Pipelines, the NJNG Area and the proposed SRL (Sources: Platts, Pinelands Commission, Skipping Stone)

Below is a TETCO Zone 3 map of the PA, NJ and NY portion of its system⁷ with arrows placed on it showing the historic (i.e., pre-shale revolution) gas flow pattern of TETCO (green arrows) and the NJNG Area (red circle).

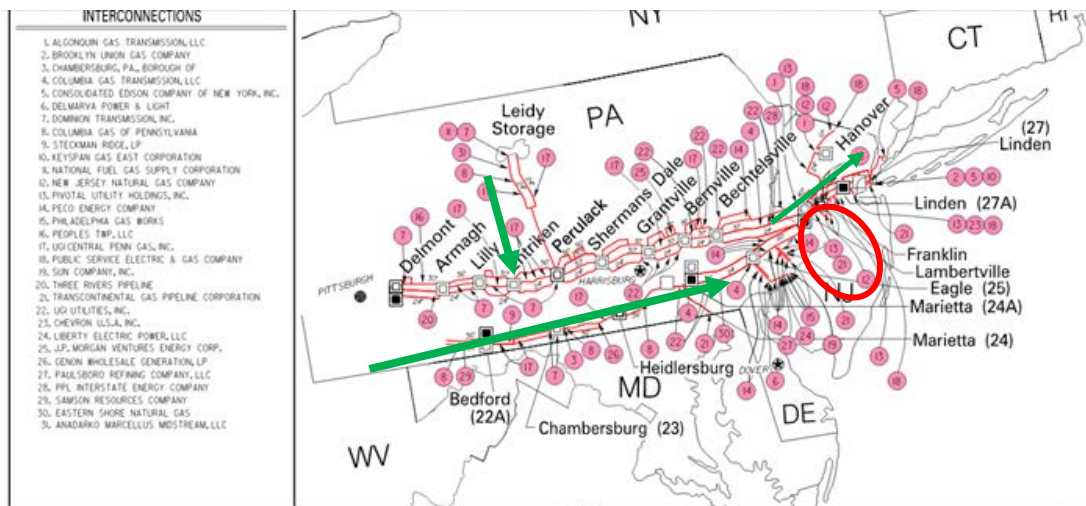


Figure 2 – TETCO Historical Uni-Directional Flow Pattern (Sources: TETCO Tariff, Skipping Stone)

As can be seen by the pre-shale stick figure additions above; all the gas that was delivered by TETCO to the NJNG Area in the winter had to come into the NJNG Area from areas to the south and west of the NJNG Area.

As will be described shortly, the discovery of large deposits of “shale” natural gas in the states of PA and OH has created a new, more diverse flow of gas to the NJNG Area as great volumes of this gas are transported across NY state and then down to the NJ-NY metropolis from pipelines delivering to TETCO in the area just to the north of the NJNG Area.

⁷ PA, NJ and NY comprise the furthest northern extent of its system which extends no further north or east.

Implications of Historical TETCO Flow Pattern on Single Point of Failure Impacting NJNG Area

With the older flow pattern, a major disruption of the TETCO system almost anywhere between the TETCO storage fields in SW PA and the NJNG Area could have reliability implications for the NJNG Area as well as any customers downstream of the major disruption location. Likewise, a disruption of the TETCO system to the northeast of the NJNG Area would not have had a reliability concern for the NJNG Area.

In summary, upstream disruptions on a long line, uni-directional flow system could have reliability implications while downstream disruptions would likely not.

The TETCO Flow Pattern Since the Shale Revolution

With the large-scale exploitation of shale gas, the pattern of gas flows in the TETCO system fundamentally changed in the NJNG Area. The new flow pattern is bi-directional and provides substantial new reliability to the system and greatly reduces the impact of a possible Single Point of Failure in the gas supply from the TETCO Mainline to NJNG.

This analysis evaluates current flow patterns on TETCO at the NJNG Area and beyond to the North and East, to the end of the line. As discussed above, the NJNG Area is those portions of Somerset, Middlesex, Monmouth and Ocean Counties where NJNG receives supplies from its pipelines and/or serves its load with such supplies (the red circle on the maps). In addition, as used in the chart below and in this report, we define the “Greater NJNG Area” as receipt and delivery points in the NJNG Area, as well as all receipt and delivery points to the North and East, up to and including the TETCO termini in NY and NJ⁸.

Following is a chart of gas flows for the Greater NJNG Area since January 2015. It is important to note that the first months of 2015 were colder overall than the first months of 2014, known as the Polar Vortex cold spell. In Chart 1, the blue line shows all the receipts of supply into TETCO from North and East of the NJNG Area. This supply can be available to serve customers to the north and east, or can flow south and west to serve the NJNG Area.

The green line on the chart illustrates that the gas being delivered by TETCO to the Greater NJNG Area is up to 3 billion cubic feet per day (Bcfd) during peak periods. During periods of high demand, there are net gas flows from the southwest to the northeast. During periods of low demand, gas flows from the north east to the south and west. The redline shows net flow direction of TETCO gas relative to the Greater NJNG Area – that is net flow **from** the south and west (positive values) or **to** the south and west (negative values).

The blue line is relatively steady because the blue line represents flow into TETCO that comes from producing areas where producers tend to flow constant quantities in an effort to get their gas to market. When the blue line occasionally dips it can be a result of maintenance on the lines connecting to TETCO or producers choosing to flow to other markets based upon price.

⁸ The receipt and delivery points to the North and East of the NJNG Area are those that were historically adjacent to and “downstream” of the NJNG Area.

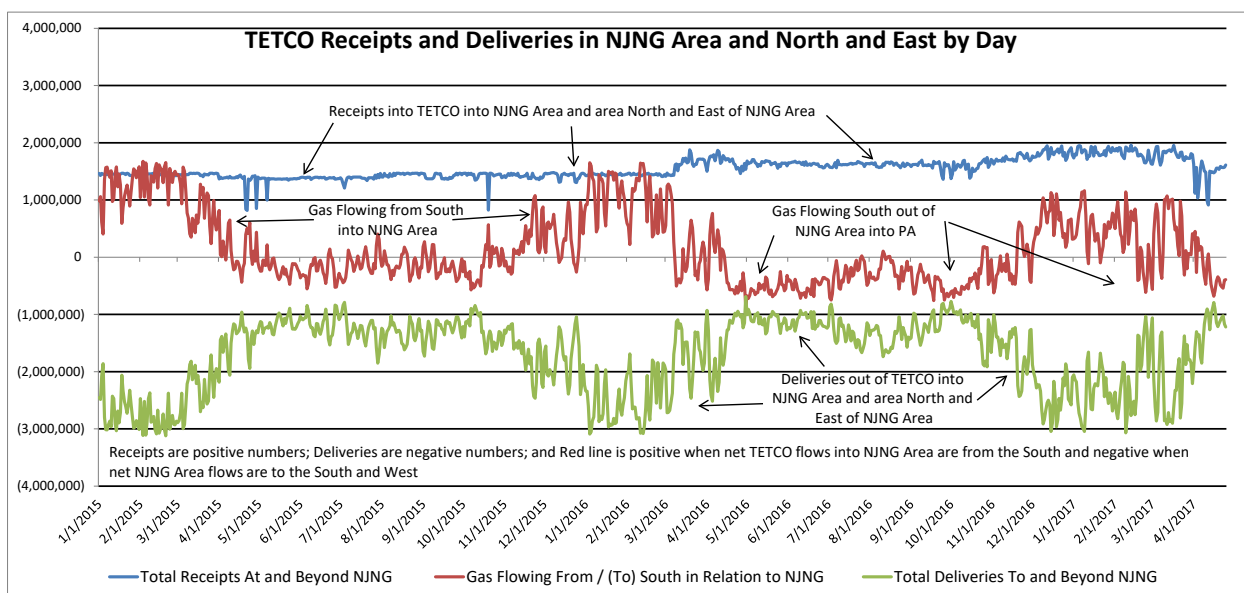


Chart 1: Receipts, Deliveries, and Net Flows Relative to NJNG Area Since Jan 2015 (Source: TETCO Flow Data, Skipping Stone)

As noted above, this chart’s green line shows deliveries out of TETCO into the NJNG Area and those locations further to the north and east of the NJNG Area (i.e., the Greater NJNG Area).

The chart’s red line is the summation of the green and blue lines, and shows net flow directions (i.e., **to** or **from** the south and west) relative to the Greater NJNG Area.

When the red line is above the zero horizontal axis, net flows are into the Greater NJNG Area and are composed of flows both from the south and west and from the northern shale supply. Likewise, when the red line is below the zero horizontal axis, net flows are out of the Greater NJNG Area and are to the south and west (e.g., for delivery to Philly).

During peak winter months, when total supplies delivered to the Greater NJNG Area reaches more than 3 billion cubic feet per day, nearly 2 billion now comes into TETCO from the North and East. Specifically, supplies flow into TETCO in the NJ counties of Bergen and Morris, and the NY county of Rockland.

This northeasterly component of supply **into** TETCO comes from pipelines located in what used to be downstream of the NJNG Area (i.e., the area to the North and East of the NJNG Area). So much flow into TETCO is coming in at the far northern end of TETCO that, **for much of the year gas flows south past the NJNG Area towards Philadelphia.**

Flow patterns from the most recent 28-month period, which covers three winter or peak periods, show that the flow on TETCO has fundamentally changed and the pipeline is now a bidirectional system. The NJNG Area is no longer at the tail-end of the TETCO system. The data show that deliveries out of TETCO to the NJNG Area may arrive from either of two directions. In addition, the new flow pattern allows the traditional supplies from the south and west to be redirected to other uses.

Identifying Potential “Single Points of Failure” of the TETCO System vis a vis the NJNG Area⁹

Below is a map of the pipelines serving the NJNG Area which has two red letters superimposed to indicate areas of the TETCO system that, *when the TETCO System was uni-directional*, were upstream of the NJNG Area (Area “A”) or downstream of the NJNG Area (Area “B”).



Figure 3: Map of Interstate Pipelines and TETCO System showing sections historically upstream and downstream of NJNG Area (Sources: Platts, Skipping Stone)

TETCO Contracts with Customers Define TETCO Service Obligations

While the recent and current pattern of gas flows identified above in Chart 1 are important, TETCO’s Firm contract obligations are also important and define what capacity service TETCO is required to provide. As of January 2017, TETCO had requirements to be able to deliver to points in NJ and NY 4.8 Bcfd. Of that 4.8 Bcfd, **0.84 Bcfd** is contracted to be *received* at the far northern end of its system, at point SS (See Figure 4), indicating the new “Shale Supply.” The Shale Supply is delivered to points in New Jersey between SS and the NJNG Area. This leaves 3.96 Bcfd that, by contract, TETCO can be required to deliver into NJ and NY from the south.¹⁰

⁹ Notably, neither NJNG nor the BPU identified or sought to quantify any possible location(s) of any Single Point of Failure, nor any attendant magnitude, probability, nor mitigation approaches. From all the documents and supplemental material in the BPU proceeding Skipping Stone found no analysis by either NJNG or the BPU remotely similar to that undertaken in this report.

¹⁰ All figures are taken from the TETCO Index of Customers filings with the FERC which pipelines are required to file quarterly and which present all the firm contractual entitlements they have with their customers including the location names at which such entitlements exist. Matching those location names with the FERC required postings of locations and their respective state and county designations enabled this analysis to be performed.

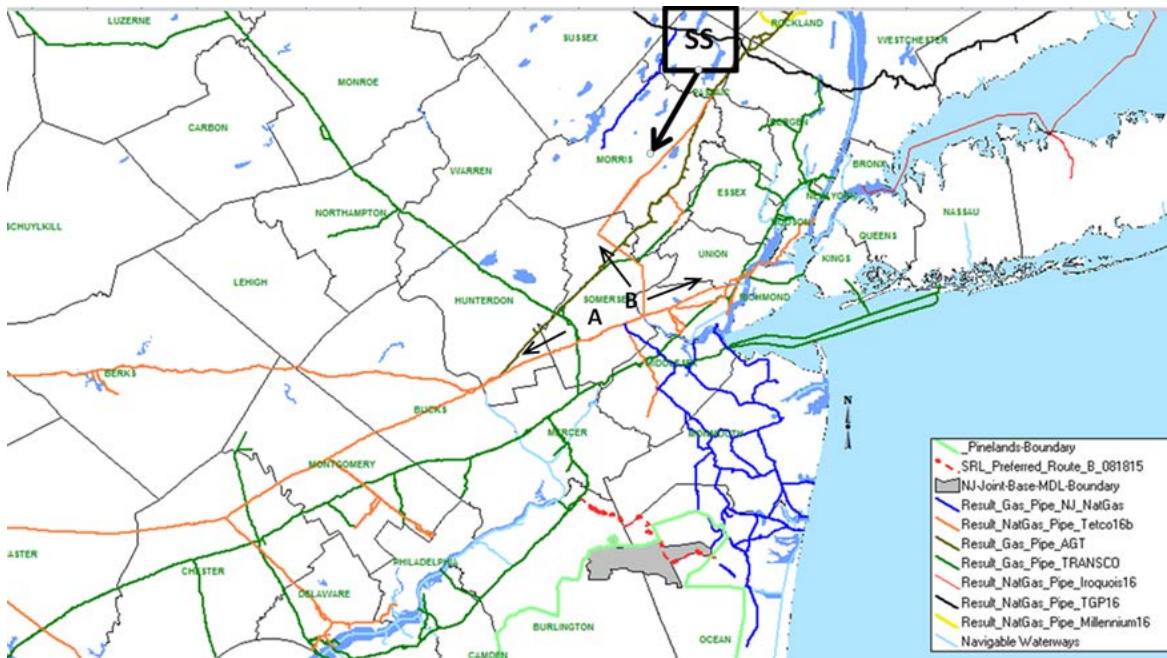


Figure 4: Map of Interstate Pipelines and TETCO System showing where new Shale Supply (“SS”) enters TETCO in relation to sections historically upstream (“A”) and downstream (“B”) of NJNG Area (Sources: Platts, Skipping Stone)

Looking at TETCO capacity from this “obligation” vantage point, it is noteworthy that while not shown on mapping software as independent lines, there are three separate TETCO lines in their right of way running south to north (i.e., from and past the “A” area) that carry this 3.96 Bcf/d, or about 1.32 Bcf/d on each line. If one such line from the south were to be interrupted (i.e., a disruption in the “A” Area) where would TETCO get the gas needed to meet that 1.32 Bcf/d of maximum firm demand which could be required on a peak day?

One option would involve bringing additional supplies from the north and east. In emergencies, gas can be redirected on the interconnected system, as long as the volume is within the physical constraints of the system. Actual data of historical delivered capacity provides an accurate depiction of minimum capacity that could flow if needed.

As noted above, TETCO already has firm obligations to receive 0.84 Bcf/d in the north that flows to the south and west. The key question is whether there is additional physical capacity that is not currently under firm contract that could be used. Recently measured flow data, as shown in Chart 1, indicates that TETCO has, in fact, received at least 2.0 Bcf/d in the north. After meeting the existing obligation of 0.84 Bcf/d, there remains about 1.16 Bcf/d of evidenced capability that could be used to fill the 1.32 Bcf/d of potential peak day demand shortfall.

If a disruption were to occur on the very coldest of days, there could be a shortage of up to 0.16 Bcf/d. The original firm demand for 1.32 Bcf/d from the south for the affected pipeline would largely be met. (i.e., 1.32 Bcf/d minus 1.16 Bcf/d or 0.16 Bcf/d)¹¹. Under pipeline allocation rules in cases of Force Majeure, this 0.16 Bcf/d of

¹¹ Under Federal Energy Commission regulations, pipelines are required to provide firm customers (situated in a zone) firm access to all receipt (i.e., supply) and delivery (i.e., market) points in that zone; at a priority of service one level down from primary (i.e., secondary) and above every other priority of service in that zone. Thus, NJNG to serve their load in the event of a disruption in the “A” Area has superior access to supply once the 0.84 have been served to the extent of their requests.

potentially remaining demand unserved (if requested), would be pro-rated among all parties in the affected area. In short, no one customer absorbs all of the shortfall. Thus, when the 0.16 Bcfd is allocated over the 3.96 Bcfd of obligations from the south on three pipelines, this means that each customer would be entitled to get 96% of their peak entitlement (i.e., 0.16 divided by 3.96 or 4%; which when subtracted from 100% yields 96%).

Impact on NJNG of a TETCO Area “A” Disruption

For NJNG, its peak TETCO entitlement into the NJNG Area (i.e., excluding the “lateral only” contract¹² and excluding the NJNG properties in Morris County) is 0.57 Bcfd. For a TETCO Area A disruption, this means that if every other customer were simultaneously taking their maximum entitlement (an unlikely but possible situation) NJNG would receive 96% of 0.57 Bcfd (or 0.547 Bcfd) or 23,000 Dth less than contracted with TETCO to serve the NJNG Area. This 23,000 Dthd or 0.023 Bcfd of potential shortfall is far less than the 70,000 Dthd available from NJNG’s Howell LNG plant and about equal to the 20,000 Dthd available from its Stafford LNG plant.¹³ On-system supplemental supplies could fill in the gap during even peak periods.

Notably this failure of an entire line (not a reduction in compression, but an entire line) would not constitute a 50% reduction for NJNG and would not be considered a “Single Point of Failure” using the BPU’s definition developed in its Standard of Decision.

Such a disruption in Area “A” would not constitute a “Single Point of Failure” because in its Zone 3 region, between the SW PA storage fields and its terminus, **TETCO is no longer a uni-directional pipeline**. It is more like a large pressure vessel with receipts and deliveries across its Zone 3 extent. And as was evidenced in the Chart 1 (the current flow pattern chart), gas routinely flows both into the NJNG Area from the north and flows to the south past the NJNG Area, as well as flowing from the south to and past the NJNG Area.

Moreover, as addressed in detail in the section concerning a hypothetical disruption of a portion of the Freehold Lateral, this potential 0.023 Bcfd shortfall (i.e., the 4% shortfall) can be addressed by simply taking more gas from the other pipelines with which NJNG has contracts to serve the NJNG Area (e.g., Transcontinental Gas Pipeline (“Transco”).

Disruption to the TETCO system in Area “B” Discussion

As presented in the preceding Figures 3 and 4 with Areas “A” and Area “B” identified, should there be a disruption at or downstream (i.e., north and east) of “B” ***it would not impact the NJNG Area***. There are two reasons for this.

First, the NJNG contracts with TETCO for the NJNG Area *do not require* NJNG to receive gas from the north; although, under Federal rules, as noted above, NJNG is permitted (and TETCO is required) to provide such access. The result is that NJNG would receive its supplies from the south and west since NJNG has a firm contractual right with TETCO to provide service from the south and west.

¹² The “lateral only” contract is a contract to recover the cost of the Freehold Lateral which is discussed in detail below and which only connects from the TETCO mainline to the terminus of the lateral and does not give NJNG access to more supply from TETCO. Rather it is a way that NJNG gets its gas flowing under other contracts with TETCO from the mainline to the terminus of the lateral.

¹³ Note this potential shortfall could also be made up by NJNG with additional deliveries to its NJNG Area from Transco as discussed in more detail below

Second, should such a disruption occur, only those customers whose locations with TETCO are situated north and east of the NJNG Area would be impacted (because Area “B” is outside of the NJNG Area). In essence, for them such a disruption would be like NJNG having a disruption at or upstream of the “A” Area.

It is also important to realize that, just because flow directions and flow patterns have changed, this ***does not*** mean that any of the physical TETCO facilities have changed; in other words, what TETCO could historically pump from south to north (i.e., to and past NJNG) can again be pumped south to north in the event of need to receive gas from the south owing to a disruption downstream of the NJNG Area (i.e., in the “B” Area).

The conclusion that can be drawn from the analysis thus far regarding a disruption impacting the TETCO Mainline at either: 1) at or upstream of “A”, or, 2) at or downstream of “B” is that even with the potential loss of an entire TETCO line,¹⁴ there would be a *de minimis* impact on the NJNG Area, and neither disruption would constitute a Single Point of Failure using the BPU definition. This is because the persistent and prevailing flow patterns on TETCO have changed, and changed to the benefit of NJNG and NJNG Area reliability.

¹⁴ The most dramatic of potential losses because it removes an entire line from service, where a compressor failure may reduce flow (to the extent the compressor is being utilized) which it is noteworthy here because when operating in a “pressure vessel” state, pipelines generally require much less compression.

Discussion of Locale of Potential Disruption Potentially Meeting Single Point of Failure Standard

The next analysis will focus on the impact on the NJNG Area should there be a failure of line along what is known as the Freehold Lateral of TETCO which connects the TETCO Mainline to the NJNG system near Jamesburg Township, NJ.

In the map below, we focus our attention on the Freehold Lateral, a 12.4 miles long, 24" pipeline.

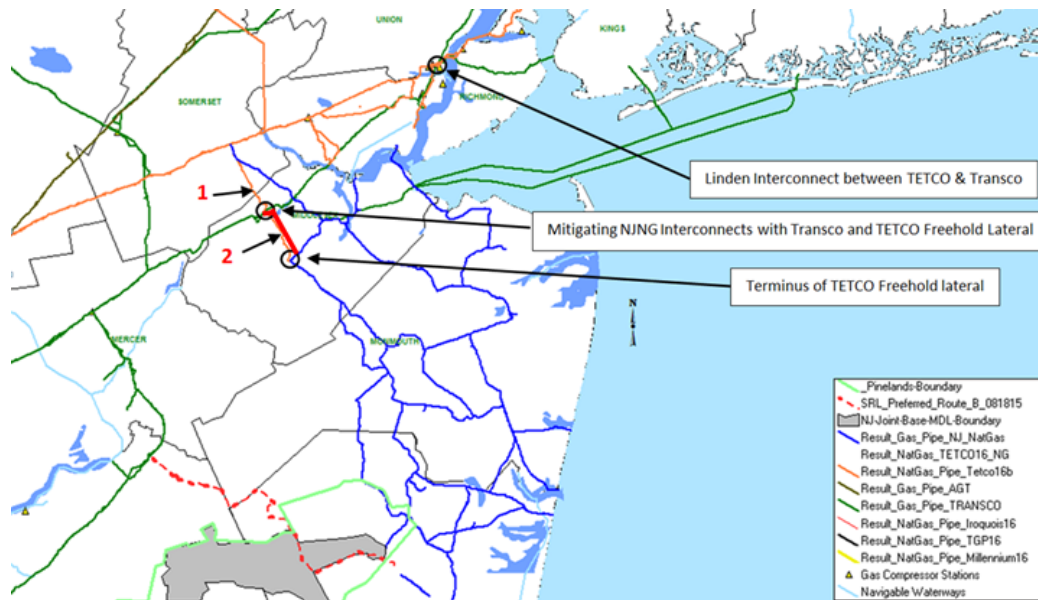


Figure 5: Map of Freehold Lateral serving the NJNG Area with Freehold Back-Up Reliability Solution showing as the redline in section labeled "2" (Sources: Platts, Skipping Stone)

The Freehold Lateral starts at the TETCO Mainline and runs 7 miles (the section marked with a red "1" on the map) to where it crosses the Transco Mainline (labeled with a circle and an arrow from a label called "Mitigating NJNG Interconnects with Transco and TETCO Freehold Lateral"). This terminology for this geographic location will be discussed below. From there, the Freehold Lateral continues another 5.4 miles (the section marked with a red "2" on the map) to its terminus where it delivers gas to NJNG in the NJNG Area.

The contracted capacity of the Lateral is posted in the TETCO Index of Customers as being 591,855 Dthd or ~0.592 Bcf¹⁵. Paralleling the Freehold Lateral (from the TETCO Mainline to its terminus in the NJNG Area) is another TETCO line, a 10" line, which pre-dates the installation of the Freehold Lateral, which went into service in April 2008. The maximum capacity of the 10" line is nominally 55,000 Dthd. For this analysis, we assumed the 10" line is still in service or could be returned to service as part of the Alternative Single Point of Failure Redundancy Solution.

¹⁵ This 591,855 Dthd is the deliverability of the Lateral while there is only 570,525 Dthd of NJNG contracted capacity to the Freehold Lateral. The difference between these two quantities could be attributed to the use of line pack on the lateral enabled by the Franklin Compressor which is located at the "head" of the lateral.

Disruption of the Freehold Lateral Presents a Potential Single Point of Failure

With respect to identifying a “Single Point of Failure” that could reduce deliveries from TETCO to NJNG by 50% (as established by the BPU in its order), the 12.4 mile long Freehold Lateral is the only section of the entire TETCO system (a 9,096 Mile long system) that poses a Single Point of Failure risk to NJNG meeting the 50% disruption standard set by the BPU.

Notably, the Freehold Lateral is a 12.4 mile section of TETCO and is only 0.13% of the entire TETCO system, moreover, it is less than 15 years old.¹⁶

That said, if that line were to break, it could pose just the kind of “Single Point of Failure” established by the BPU as a risk to avoid. Given this risk, as established above, the BPU justified the building of the SRL. This raises the obvious question: Is the SRL, the least expensive, least disruptive means of addressing such a Single Point of Failure risk?

The short answer is “No.” The BPU did not consider, nor did NJNG analyze, alternative means of addressing this specific, if highly remote, failure scenario.

Addressing the Potential Single Point of Failure Risk

To address a possible failure of the Freehold Lateral, Skipping Stone analyzed the maps of the Lateral’s environs and established that there were two distinct possible failure scenarios needing to be evaluated.

The first would be a break along Section 1; with the second being a break along Section 2. We address both possible breaks with what we call the “Alternative Single Point of Failure Redundancy Solution or the “Freehold Back-Up Reliability Solution” for short.

The Alternative Single Point of Failure Redundancy Solution a.k.a. the Freehold Back-Up Reliability Solution

The “Freehold Back-Up Reliability Solution” (or FBURS) would be as follows:

- 1) NJNG to install 5.4 miles of 24” line from the location labeled “Mitigating NJNG Interconnects with Transco and TETCO Freehold Lateral” to the lateral’s terminus, thus effectively duplicating the TETCO Lateral’s function between the Transco mainline and the NJNG service area. This would extend the NJNG system to the Transco-TETCO Lateral crossing point. We refer to this new pipeline as the Freehold Back-Up Reliability Solution, and it is depicted on the map as the red line in the Section labeled “2.”
- 2) NJNG would install two new interconnects between the new line and its interconnecting interstate pipeline gas supply sources: one with TETCO on the Freehold Lateral at the location entitled “Mitigating NJNG Interconnects with Transco and TETCO Freehold Lateral” and the other with Transco at the same location.

¹⁶ A pipeline installed in the last 15 years is considered “new”. The Freehold Lateral was installed with all the most current engineering, safety, and inspection standards, giving it a very high degree of reliability. Note that much of the TETCO system was built in the 1940’s through the 1960’s making the vast majority of the TETCO system 60 or more years old.

- 3) TETCO would install a “Block Valve” on its Freehold Lateral downstream of the new NJNG Interconnect with TETCO on the Freehold Lateral¹⁷ allowing partial isolation of the Freehold Lateral should a disruption occur within Section 2.

The FBURS addresses possible independent failures of either of the line’s segments in Section 1 or Section 2. A possible Section 1 failure is addressed as follows.

Scenario 1

In the case of a Section 1 line failure, instead of NJNG getting its gas down the Freehold Lateral all the way to its terminus, NJNG would get some of its gas (~55,000 Dthd) along the 10” line to its system and would get the remainder of its gas from Transco at the new Transco interconnect where it puts the gas from Transco through the new NJNG 24” line to its system. (How the gas gets from TETCO to Transco at the new interconnect is discussed below).

With a line break in Section 1, TETCO would deliver into the 10” line the 55,000 Dthd discussed above; TETCO would also deliver NJNG’s gas to two northern Transco-TETCO interconnect locations in NJ for backhaul delivery on Transco to the new NJNG interconnect for subsequent onward delivery to NJNG via the new 24” FBURS line. Those two locations are Linden, at the very end of the TETCO and Transco lines just before NY, and Belle Meade, which is just a bit north of the new NJNG interconnect with Transco discussed above. Gas received by Transco at the interconnects, would be delivered by backhaul,¹⁸ because gas otherwise flowing on Transco to the north and east of Belle Meade that came from the south would enable gas to flow southward on Transco to the new 24” NJNG FBURS line interconnect.

The amount of gas that TETCO can deliver to Transco at Linden (a point that is rarely used) is 430,622 Dthd¹⁹. In addition, TETCO has delivered to Transco at Belle Meade in Somerset County a total 151,545 Dthd²⁰ to all shippers. In our modeling, we did not assume that this full amount would be available for NJNG to route gas to Transco; rather we calculated a lower bound for the potential capacity available to NJNG. That bound was the amount between the maximum delivered to Transco (i.e., the 151,545 Dthd) and the amount at which the Belle Meade interconnect is operating at its average condition (64,899 Dthd²¹) during the January 2015 through April 2017 period. This approach yielded an available lower-bound amount of 86,555 Dthd at the Belle Meade interconnect that NJNG might use in an emergency situation.

This analysis shows that rerouting NJNG supplies to Transco and back to the new Transco interconnect is possible, but is not entirely under the control of TETCO. With conservative assumptions, we arrive at a total of

¹⁷ This would be necessary only to the extent TETCO does not already have one or more of such valves already along the Freehold Lateral in the vicinity of its Transco crossing.

¹⁸ These deliveries into Transco would be delivered to NJNG by backhaul because the gas delivered by TETCO would flow into NY and the gas otherwise destined for NY would be delivered to NJNG upstream (i.e., to the west of Linden) – which is the definition of backhaul; a common practice in the wholesale natural gas industry; and required by pipeline tariffs to the extent gas is otherwise flowing in the forward haul direction between the upstream delivery location and the downstream receipt location.

¹⁹ This is the amount of gas (daily capacity) posted by Transco as available to be received from TETCO at Linden.

²⁰ This amount was delivered during an “Shoulder” period (i.e., October of 2015)

²¹ This is the amount of TETCO average deliveries over the Jan 2015 through April 2017 time period deliveries when those deliveries were equal to or less than the listed Design/Operating capacity discussed above.

approximately 572,177 Dthd (or ~0.57 Bcfd) that could be delivered to NJNG, just enough to fully satisfy 100% of NJNG's peak TETCO Freehold Lateral entitlement of 0.57 Bcfd²². The total includes the 55,000 Dthd capacity of the 10" TETCO lateral and the sum of the alternate routes (to Linden and to Belle Meade). Thus, the Freehold Back-Up Reliability Solution enables reduction of the potential disruption to the NJNG Area to well below the 50% threshold (i.e., to 0% to 4%) for Single Point Failure threshold set by the BPU. To further mitigate the risk of any shortage, we evaluated additional factors that would increase the total capacity available to NJNG, making it highly likely that it would receive 100% of its capacity in the event of a failure in Section 1 of the Freehold Lateral.

Scenario 2

In the case of a Single Point Failure along Section 2 of the Freehold Lateral, TETCO would close the Block Valve discussed above and divert (deliver) gas from Section 1 into the new NJNG interconnect for onward delivery to its system through the new FBURS 24" line. In the case of an interruption along Section 2, Transco is not involved in the resolution.

Transco Supplies to the NJNG Area Can Supplement the Alternative Freehold Back-Up Reliability Solution

In the unlikely event that the less than 15-year-old TETCO line comprising Section 2 does fail and the above routing of NJNG's TETCO gas through Transco to the new interconnect and redundancy line is still insufficient, NJNG can also receive as much as an additional 160,000 Dthd throughput at its interconnections with Transco at the far northern end of the NJNG system to supplement its requirements.

For instance, in the winter of 2016, NJNG received as much as 179,802 Dthd from Transco at its two Transco location(s).²³ This amount is ~161,000 Dthd in excess of NJNG's firm entitlements on Transco.²⁴ This 179,802 Dthd amount is 138,000 Dthd in excess of NJNG's average take on Transco during the November thru March period of 2016. Skipping Stone notes that the BPU in its Order stated, "These two Transco interconnections have an approximate capacity of 76,500 and 124,500 Dth/day." This 200,000 Dthd total cited by the BPU is 21,000 Dthd higher than deliveries recorded in the January through March 2016 period; and, if true, provides even more capability to make up for any shortage not directly addressed by the Freehold Back-Up Reliability Solution. In all likelihood, any possible shortfall in back-hauling gas through TETCO-Transco interconnects could be overcome by using the two existing Transco-NJNG interconnects (that are contractually undersubscribed relative to evident Transco capability).²⁵

²² Although, for the duration of the Force Majeure period affecting Section 1 of the Freehold Lateral, the additional deliverability due to line-pack (facilitated by the Franklin Compressor at the lateral origin) of the Freehold Lateral would not be available.

²³ Transco, in its postings of flow data, aggregates its customers' points that consume capacity along a discreet segment of its pipe into one number for the aggregated point(s).

²⁴ As of the January 2017 Index of Customers for Transco, NJNG had three contracts totaling 18,600 Dthd of entitlement.

²⁵ This contractual "undersubscription" is at the location. It is unlikely that Transco is contractually undersubscribed on a forward haul basis along the segment on which the location resides. The quantities observed as delivered to NJNG from Transco either arrived on other shippers' contracts with rights to deliver in that area of Transco or were delivered by means of backhaul from NYC on that segment.

Note also that the apparent ability of NJNG to accept deliveries from Transco to fully eliminate any potential shortfall occurring with Transco back-hauls cited here, also applies to the possible 4% shortfall due to curtailment resulting from a TETCO mainline disruption in Area “A.”

Thus, with the existing unutilized capacity at the existing Transco interconnects, *the alternative Freehold Back-Up Reliability Solution reduces the potential disruption of the Freehold Lateral to near zero percent supply loss, well below the 50 percent supply loss level set by the BPU as justification for the SRL. The Freehold Lateral is the only portion of TETCO that could conceivably cause a 50% reduction in supply to NJNG.*

As explained below, the Freehold Back-Up Reliability Solution is superior to building SRL because it would be vastly less expensive to ratepayers and avert SRL’s impacts on communities and natural resources.

Additional Likely Mitigation Measures Available to NJNG in the Event of the Single Point of Failure Risk involving the Freehold Lateral

During the periods of peak usage, when NJNG was taking the highest volumes of gas from its transmission pipelines (including, of course, its major source of supply – the Freehold Lateral), NJNG was serving natural gas fired electric generation plants.²⁶ This is significant and important because these loads are not considered “firm” loads under the NJNG tariff and would be interrupted during a period of Force Majeure, which the disruption of the Freehold Lateral would certainly be considered. The interruption of such loads would in turn reduce NJNG’s demand needing to be served.

The Level of Interruptible Electric Generation Demand Able to Contribute to Mitigating a Single Point of Failure Event.

NJNG serves several natural gas-fired generation plants in its service territory. The two most substantial of which (according to EIA 2016 data) are the Lakewood Cogeneration and Ocean Peaking Power Plants both listed as being operated by Essential Power.²⁷

According to EIA data, these two plants, when operating, have combined minimum MW run rates of 204 MW and 240 MW respectively.²⁸ To be conservative for likely mitigation purposes, assuming minimum MW operating levels, EIA data indicates the Lakewood plant operated approximately 16 hours per weekday²⁹ during

²⁶ See data response of NJNG S-NJSRL-16 where NJNG states that on the peak days listed in that response “...that Electric Generation volumes are included in the data”.

²⁷ Essential was recently acquired by and integrated into the Carlyle Group in late January of 2017.

²⁸ Maximum Winter period MW ratings of these two plants, according to EIA, are 251 MW (Lakewood) and 375 MW (Ocean Peaking).

²⁹ Calculations indicate that both units at the Lakewood plant would have operated ~376 hours at minimum load for that plant to produce the electricity it produced. In January 2016, there were 21 weekdays (including January 1st). Assuming 16 hours of operation per weekday (i.e., the typical PJM 6:00 AM to 10:00 PM weekday block) thus yields 336 weekday operating hours. At peak output, both units at the Lakewood plant would have operated 365 hours in January to produce its January output. This means that both units at the Lakewood plant, depending on operating output level, operated between 29 and 40 hours outside of the 16-hour per weekday periods in January 2016. The more efficient unit at the Lakewood plant is estimated to have operated additional hours (i.e., between 37 and 171 hours) in January depending on whether the units operated at minimum or peak output. Skipping Stone assumed the same average daily gas use because gas use is most closely dependent on output.

January and February of 2016³⁰. Based upon EIA data with respect to its output of electricity per input of fuel, Skipping Stone determined that this plant consumed ~ 36,704 Dthd on average in January and ~27,573 Dthd in February when operating.

Thus, assuming a Single Point of Failure (i.e., along the Freehold Lateral), during a worst case period of time (January), NJNG, by interrupting deliveries to the Lakewood plant, would reduce demand for gas by this 36,000 Dthd; which, with all the other mitigation measures outlined above and available to NJNG, would enable NJNG to completely avoid any disruption to firm residential and commercial load – without having to build the SRL - in order to achieve the goal of NJNG system resiliency, provided the FBURS was in place.

Comparative Cost of Alternative Freehold Back-Up Reliability Solution and SRL

The approximate cost of the alternative Freehold Back-Up Reliability Solution” is made up of two components.

1. The cost of the two interconnects which Skipping Stone estimates to be ~\$1.5 Million apiece³¹;
2. The cost of 5.4 miles of pipeline which it estimates as being \$4.2 Million per mile³² or ~\$22.7 Million for the redundancy line which yields a total cost of ~\$26 - \$28 Million.

Notably this alternative’s cost is more than \$150 Million less than the NJNG estimated cost of the SRL³³ “solution” to a Single Point of Failure.

Not only is the cost of the SRL nearly five times the likely cost of the Freehold Back-Up Reliability Solution proposed here, but the FBURS traverses existing Rights of Way without any of the additional community and Pinelands Area impacts attendant to the SRL Single Point of Failure “solution” adopted by NJNG. This approach could also help NJNG avoid the regulatory tangles and fierce public opposition SRL faces.

Comparison of the SRL Solution to a Single Point of Failure along the Freehold Lateral

If SRL were to be built, NJNG would obtain 0.18 Bcfd from Transco³⁴ at the new connection to SRL. In the event of a failure in either Section 1 or 2 of the Freehold Lateral, NJNG would lose 100%, or 0.57 Bcfd, of supplies to its TETCO terminus. SRL would protect NJNG against a loss of only about a third of the current total requirement (i.e., a 66% supply loss) which exceed the 50% level identified by the BPU.

Thus, in an emergency, the SRL solution would leave a gap of about 0.39 Bcfd, or ~66% of the capacity that NJNG requires to meet its peak needs, with no strategy or capacity to avoid a major disruption of service. In contrast, the Freehold Backup solution would meet all of NJNG requirements, resulting in no disruption to its customers,

³⁰ The Ocean Peaking Power Plant operated only 3 hours in January and 2 hours in February and thus can be disregarded as able to contribute to demand mitigation actions available to NJNG.

³¹ If the pipelines insisted that they (i.e., the pipelines) build the interconnect meter stations; and NJNG preferred to reimburse the pipelines rather than pay the pipelines a “return on investment” for years to come; and therefore determined to pay for the meters, this is considered a Contribution in Aid of Construction or CIAC, and the tax gross-up effect, if insisted upon by the pipelines, would turn the ~\$3.0 Million into ~\$4.6 Million

³² This is based upon the cost of the 30” SRL line scaled down from 30” to 24” in diameter.

³³ SRL is estimated to cost ~178 Million Dollars.

³⁴ See documents filed by NJNG in BPU Docket Nos. GO15040403 and GO15040402 and capacity provided by Transco’s Garden State Expansion (GSE) which is proposed to feed the SRL (See Exhibit P to Transco’s GSE FERC application). The GSE consist of a compressor and meter station capable of flowing 0.18 Bcfd which effectively limits the potential SRL flows to 0.18 Bcfd despite its 30” diameter size.

at \$100 million less than the cost of SRL. SRL, therefore, cannot be considered an effective and reasonable response to the Single Point of Failure scenario on which BPU based its decision.

Answering the Question: “What magnitude of disruption of TETCO would necessitate a facility of the magnitude of the SRL in order to address the failure of such magnitude?”

At the outset, the PPA asked Skipping Stone to answer this question. The short answer is that Skipping Stone was not able to construct an even remotely reasonable scenario for a Single Point of Failure that could only be addressed by a facility of the magnitude of the SRL. While we were able to conceive of two possible failures of the TETCO system (i.e., the two separate scenarios of a complete failure of the Freehold Lateral), Skipping Stone also identified a solution to not only mitigate, but substantially eliminate such remote risk. Moreover, it does so at ~20% of the cost of the SRL and with 1/6th the length of pipe and attendant potential environmental disruption.

Joint Base Load and Relevancy of SRL to Joint Base Service Reliability

Skipping Stone was asked to review the SRL and its capacity, and to analyze what, if any, contribution to the Joint Base’s service reliability from NJNG the SRL might provide that would *not* be available from the FBURS.

According to a 2013 submission³⁵ prepared by EHS Technologies for Army CERDEC Flight Activity, the annual natural gas load of the Lakehurst portion of the Joint Base at that time was 246,481 Mcf per year (roughly equivalent to 254,368 Dth per year³⁶). Assessing the typical peak day as a percentage of annual weather sensitive load, which is the load characteristic of the Base’s natural gas use, a weather sensitive Northeast U.S. load’s peak day use of natural gas is generally 1% of annual use. This would make the Base’s peak day usage ~2,544 Dthd. Comparing this to NJNG’s recent peak day send-out of 640,937 Dthd, the Base’s load is 0.4% (i.e., less than ½ percent) of NJNG’s recent peak and 0.043% of the sum of NJNG’s contracted capacity entitlements³⁷ for the NJNG Area (in which the Base resides).

Our analysis of this load (both its type – i.e., firm – and relatively de minimis magnitude) leads us to conclude that the SRL’s capacity (as opposed to the FBURS’ proposed capability) provides no additional reliability to the Joint Base load vis-a-vis a Single Point of Failure as set forth in the BPU Order.

³⁵ This submission referenced 2010 data.

³⁶ Using a typical Btu/cf conversion factor of 1,032 Btu’s per cubic foot and 1 million Btu’s per Dth

³⁷ The sum of NJNG TETCO NJNG Area contracts of 570,525 Dthd and its Transco contracts of 18,600 Dthd; both as posted in the respective pipelines’ Index of Customer for January 2017.

Conclusion:

Below is a Table Summarizing the results of Skipping Stone’s analysis of whether the proposed SRL is an appropriate facility for the purpose of addressing a Single Point of Failure as set forth by the BPU.

Possible Location of Pipeline Failure	Estimated Capacity Loss	Mitigation Actions Required?	Additional Mitigation Required?	Estimated Capacity Reduction for NJNG after Mitigation (worst case)	Meets Single Point of Failure Criteria?
TETCO Upstream of NJNG	1.32 Bcfd	Only if occurs on highest demand day(s). If so, receive TETCO supplies from North and possibly interrupt Electric Gen	None Required	0% to ~4%	No
TETCO Downstream of NJNG	1.32 Bcfd	No. Receive TETCO supplies from South and West per current contracts	None Required	0%	No
TETCO Freehold Lateral Section 1:	0.57 Bcfd	Yes, build ~ \$22-\$26 Million FBURS, and receive supplies from Transco and interrupt Electric Gen	FBURS	0%	Yes, absent Mitigation
TETCO Freehold Lateral Section 1:	0.57 Bcfd	Yes, however, even with SRL and interruption of Electric Gen, loss of gas supply would be 66%	SRL³⁸	66%	Yes, even with SRL
TETCO Freehold Lateral Section 2:	0.57 Bcfd	Yes, build ~ \$22-\$26 Million FBURS, and in FBURS case receive supplies from TETCO	FBURS	0%	Yes, absent Mitigation
TETCO Freehold Lateral Section 2:	0.57 Bcfd	Yes, however, even with SRL and interruption of Electric Gen, loss of gas supply would be 66%	SRL³⁹	66%	Yes, even with SRL

As discussed throughout this Report, Skipping Stone concludes that while there is a potential Single Point of Failure risk attendant to a remote (but non-zero) possibility of loss of the 15 year-old Freehold Lateral, the proposed SRL is not a reasonable solution to mitigating that risk, and in fact would not be sufficient to address the loss of the Freehold Lateral. Because:

as noted by the BPU in its Order, the SRL as proposed could, at most, meet a loss of barely one-third the magnitude of that attendant to the loss of the Freehold Lateral.⁴⁰ If the SRL’s uncontracted-for, but designed,

³⁸ As proposed and as contracted for with Transco via the Garden State Expansion

³⁹ Ibid.

capacity of 280,000 Dthd plus the 55,000 Dthd of TETCO's 10" line were available, then 335,000 Dthd would mitigate just over 60% of the only Single Point of Failure identified by Skipping Stone and thus is barely adequate to address the only such failure (i.e., 50%) set by the BPU as the standard for its decision.

If addressing a Single Point of failure is truly the problem to be solved, the proposed SRL does not do that. Only if all electric generation were interrupted and somehow uncontracted-for capacity were to be available to NJNG to flow through the SRL would it reduce the loss of supply to meet demand to a 34% level, and at a cost five times that of the Freehold Back-Up Reliability Solution, which solution would address all but at most 4% of peak demand.

Only a solution as outlined by Skipping Stone (or a similar one designed to meet the real risk) can mitigate the full risk posed by the only Single Point of Failure identified by means of comprehensive analysis. Such an analysis was not previously sought nor was one provided in the record of the SRL proceeding.

⁴⁰ At page 13 of the March 16, 2016 BPU Order the BPU states: "In the event of a fifty (50) percent reduction of supply from TETCO, which exceeds the capacity provided by a twenty-four (24) inch pipeline, the design of SRL would ensure transmission system integrity. In the event where a large scale TETCO interruption occurs, even without upgrades to the Transco interstate system, with a 30-inch pipeline the company could acquire in excess of the contract volume [i.e., 180,000] by entering into transactions with other firm shippers that have rights on the interstate system. ... Additional capacity transacted for in the event of an interruption (e.g., 280,000 Dth/day) could not flow through a twenty-four (24) inch pipe because it would result in an unacceptable pressure drop.

EXHIBIT C

VERIFIED STATEMENT OF GREGORY LANDER OF
SKIPPING STONE IN RESPONSE TO
LONDON ECONOMICS INTERNATIONAL REPORT
(February 7, 2022)

VERIFIED STATEMENT OF GREGORY LANDER OF SKIPPING STONE IN RESPONSE TO LONDON ECONOMICS INTERNATIONAL REPORT

I. Introduction

1. My name is Gregory M. Lander. I am President of Skipping Stone, LLC (“Skipping Stone”). My business address is 83 Pine Street, Suite 101, West Peabody, MA 01960.

2. I graduated from Hampshire College in Amherst, Massachusetts, in 1977, with a Bachelor of Arts degree. I co-founded and ran an independent gas marketing firm in the early to late 1980s and was involved with energy transaction information technology development through the 1990s. Since 1999, I have headed up Skipping Stone’s Energy Logistics practice, where my specialization has been interstate pipeline capacity issues, information, research, pricing, acquisition due diligence, project development related planning and consulting for pipelines, potential project shippers and policymakers. I have experience with a wide range of pipeline transportation issues, beginning with access to pipeline capacity to make competitive sales, resolution of the pipeline take-or-pay contracting regime, pipeline affiliate marketer concerns, restructuring of the pipelines from merchants to transporters and thereafter, and definitions of what constituted a pipeline capacity “right” for the purposes of formulating the then newly commenced capacity release and capacity rights trading business process. I continue to be involved in nearly all facets of the capacity information and trading business as part of my duties at Skipping Stone. I have been the lead principal on 50+ pipeline and storage mergers and acquisitions transactions as well as pipeline and storage facility expansion projects for which Skipping Stone has been retained by potential purchasers and project sponsors to provide economic due diligence consulting and market analysis. In addition, I was lead consultant for a PJM Interconnection L.L.C. power plant with respect to installation of back-up liquefied natural gas (“LNG”) supply for start-up gas and have more than 30 years of experience with LNG related issues, infrastructure and energy policy. I have pipeline, LDC, producer, power generator, process end-user and consumer/environmental advocate clients nation-wide that I consult with on the physical, contractual, operational and economic interdependencies between natural gas market segments as well as their increasing cross-interdependency with electric markets.

3. This Verified Statement responds to several key findings from the London Economics International Report (“LEI Report”) but does not otherwise take a position on the remaining aspects of the LEI Report. I offer these points to inform Board Staff’s recommendations to the New Jersey Board of Public Utilities (“NJBPU”) Commissioners.

II. LEI's Report Contains Analytical Errors that Result in an Understatement of Gas Capacity Available to GDCs

A. Underestimates Related to North-to-South and South-to-North Pathways Through New Jersey

4. LEI contrasts the Levitan and Skipping Stone reports on pages 14 and 15. In this analysis, LEI correctly observes that the Levitan Report only counted capacity under contract to Gas Distribution Companies ("GDCs") and only counted capacity under contract to Producers/Marketers, which capacity had primary delivery points in New Jersey as being "available" to GDCs to meet demand.¹

5. However, LEI failed to acknowledge that some of the "GDC capacity" actually has primary delivery points outside of New Jersey. There are three GDCs with primary delivery points in New York. Both Levitan and Skipping Stone included the capacity under these contracts. This is because capacity contracted to primary points in New York under GDC contracts should be counted because the capacity path (from receipt to delivery) passes through New Jersey. Similarly, that is why Skipping Stone counted additional capacity held by non-GDC shippers with delivery capacity both in New Jersey and with primary capacity paths passing through New Jersey. Skipping Stone counted both "South-to-North" and "North-to-South" firm, contracted, capacity with paths passing into and/or through New Jersey. Levitan failed to include that capacity, resulting in an underassessment of available capacity in excess of 2.4 Bcfd.²

6. Based upon the work I have done over the past twenty years, the average peak day use of natural gas per household ranges from eight therms per day to twelve therms per day. There are ten therms in a Dekatherm (Dth) and a Dth is approximately equal to a thousand cubic feet of natural gas (Mcf). 1 Bcf is a million Mcfs. Using the high-end of the eight to twelve therms per day range, associated with both larger homes in more northern climates, 2.4 Bcfd is enough capacity to supply the gas needed to heat well over two million single family homes on a deep winter, high demand, day.

B. Underestimates Resulting from Exclusion of Additional Users' Demand

7. LEI critiques Skipping Stone's capacity sufficiency assessment report for including the demands of other users in New Jersey. Skipping Stone included these other demands for good reason. This inclusion is important to note because *including these "uses" of gas*, along with that of the gas delivered to GDCs, (which also includes "other than firm demands") demonstrates that there was still existing capacity, to and through New Jersey, even after such actual loads were served. This existing capacity, even after

¹ See LEI Report at 14 (Section 1.3.5(1)).

² See Comments of The Environmental Defense Fund and New Jersey Conservation Foundation, NJBPU Docket Nos. GO20010033, GO19070846 (May 18, 2021), at 6 (represented as the difference between the orange Levitan line and the top, dashed, grey line).

accounting for additional demand from other users *in addition to* GDCs’ actual historical flows, was in excess of 1 Bcfd on the highest needle peak demand day of the 2014-15 through 2018-19 periods. It appears that LEI misapprehended Skipping Stone’s point: when one includes additional demands, there is still excess capacity. This additional, excess of, 1 Bcfd of capacity enhances reliability, and Board Staff should consider this when reviewing the LEI Report, and in making its planning recommendations to the Board.

8. In fact, LEI *acknowledges* that this interruptible demand represents a common and reliable way for gas systems to balance supply and demand on a design day. Ironically, in presenting Skipping Stone’s inclusion as an error, LEI’s attempt to explain why it is an “error” actually confirms Skipping Stone’s analysis that this capacity enhances reliability:

“Skipping Stone’s estimated 5,600 MDth/d historical peak demand included all customers (for example, it included power generators), not just firm customers of GDCs. The historical peak of firm demand from GDCs in 2018/19 was about 4,000 MDth/d, as shown previously in Figure 19. By including demand from the electric power sector and all other customers, the Skipping Stone Affidavit made it appear that historical peak demand (the 5,600 MDth/d for 2018/19) is comparable to the design day demand of 5,009 MDth shown by Levitan (see Figure 36). It is not comparable. *Demand from many commercial, and industrial GDC customers is interruptible and thus provides a commonly used and reliable way for the gas system to balance supply and demand on a design day; and supply to the power sector is rarely firm.*”³

9. Precisely because “not just firm” (i.e., interruptible) customers could be interrupted, the capacity that had been used to serve them would be exactly the capacity available to serve “firm customers,” should the GDCs pay to have that gas delivered to the GDCs to meet their firm load instead of to the interruptible customers. The capacity does not *disappear* if not used to meet interruptible customers’ demands – price can bring that supply to the GDCs. Nonetheless, it is important for Board Staff to understand, first, that even *after* the 5,600 MMDth of load (Skipping Stone calculated actual demands for firm *and interruptible*⁴), there was still over 1 Bcfd of available capacity to and through New Jersey. Second, Staff should contextualize this significant quantity properly for the Board as it proceeds to update and enhance its planning processes.

10. As noted above, this quantity in excess of 1 Bcfd is sufficient to serve the daily requirements (on these same historical peak delivery days) of between an additional 830,000 and 1,200,000 households’ -- without interrupting interruptible loads also served on those same needle-peak days.

³ LEI Report at 83 (emphasis added).

⁴ All “load” data was collected from the pipelines’ federally required standard daily postings of scheduled quantities by location.

C. Underestimates Resulting from Excluding GDCs' On-System Peaking Capability

11. LEI correctly asserts that Skipping Stone did not include GDCs' on-system peaking capacity. The purpose of the Skipping Stone report was to critique Levitan's assertions regarding available *pipeline* capacity. All GDC peaking capacity, to the extent it was un-used on the days of peak pipeline deliveries presented in the Skipping Stone report, would simply serve to raise the top "capacity available" line *further above the 7 Bcfd line*.⁵

Skipping Stone's report was not intended to assess all GDC resources; but rather to point out that additional *pipeline* capacity, as identified by the Levitan report, was not needed. Notably LEI agrees with this as well in its report.⁶ However, in both a capacity planning context, and viewing LEI's broader scope of work, including these additional resources and their potential for further optimization, it is appropriate to include these existing non-pipeline alternatives in all future planning processes.

12. Further, when analyzing existing *pipeline* capacity, Skipping Stone showed that actual deliveries to New Jersey locations *far* exceeded the Levitan-cited capacity in all of the most recent 5 studied gas years for as many as 73 days in each year.⁷ The observed actual deliveries exceeded Levitan capacity figures. This alone indicates that the capacity to and through New Jersey was sufficient to make actual deliveries using the same "to and through" capacity identified by Skipping Stone. To the extent New Jersey GDCs have additional supply resources⁸ that were not used during one or more of the 73 days that actual deliveries exceeded Levitan's 2019 pipeline capacity line, the sufficiency of total resources to meet demand are understated in the Skipping Stone report. These additional supply resources further enhance reliability. While the LEI report did not comment on this observed, delivered gas reality, nor set out this additional data point as a significant one for the Board to ask GDCs to produce, it would be important for Board Staff to include these data and questions in their review and recommendations going forward.

⁵ See Comments of The Environmental Defense Fund and New Jersey Conservation Foundation, NJBPU Docket Nos. GO20010033, GO19070846 (May 18, 2021), at 6.

⁶ See LEI Report at 2 where it states that current capacity of the GDC's – (i.e., not considering the additional available capacity identified by Skipping Stone) should be sufficient to meet LEI estimated GDC loads through 2030. See also *id* at ("LEI's main findings are that, through 2030, firm gas capacity can easily meet firm demand under normal winter weather conditions, in cases of colder-than-normal weather on a scale experienced in the past, and even in the case of a design day.").

⁷ See Skipping Stone Report at 6 (chart demonstrating deliveries exceeding proffered Levitan capacity figures).

⁸ These include on-system peaking resources like LNG, CNG, propane air and/or demand response.

III. LEI's Report Conflates Price with Availability, And It Is Important To Disaggregate These Concepts

13. The LEI Report asserts that Skipping Stone “ignored what happens during capacity-constrained periods.”⁹ Skipping Stone suggests that LEI clarify this point, or that Board Staff take note of it when making recommendations based on the LEI Report, because the same capacity exists during constrained and non-constrained periods.

14. When production exceeds the pipeline capacity to move all supply from points of production to points of consumption; the producer sees capacity constraints in the form of depressed prices. Similarly, when demand exceeds the pipeline capacity to serve all of the demand at delivery point(s) out of the pipeline, those in the market see prices for available supply increasing, sometimes dramatically.

15. Thus, what “changes” during periods of constrained capacity is the value that can be extracted by use of that capacity. Moreover, what LEI should have stated, is that during periods of high-demand, the value of capacity to and through high demand locations has greater value; and that this value is expressed in the price that “delivered gas” can command. However, price cannot and should not be conflated with either capacity availability or reliability. The same capacity is available and its value during those periods of high demand will be reflected in the price of gas delivered using that capacity.¹⁰ Board Staff should be careful to ensure that its gas planning inquiries and processes carefully distinguish between price and availability/reliability, both in this context, in the context of redirecting supply from interruptible customers, as described above, and in the context of comparing between and among alternatives to meet agreed future firm demand.

IV. GDCs Have Multiple Tools to Secure Available Capacity

16. Skipping Stone’s prior Affidavit was a critique of the Levitan report’s assertion that GDCs needed additional pipeline capacity; it was not intended to be a comprehensive study of GDC assertions as to GDC demand. LEI failed to properly contextualize the Skipping Stone Report, and thus made unwarranted criticisms like, “[t]he Skipping Stone Affidavit did not examine demand appropriately, and (as discussed below) made claims for the volume of available capacity that are not relevant at times of system constraint, which together led to estimates of a huge volume of available supply capacity on the system, with the implication that this capacity would be available at any and all times.”¹¹

17. The first part of this assertion has been addressed in Part II above, where Skipping Stone reviews its inclusions of available supply capacity and LEI’s confusion in

⁹ LEI Report at 14.

¹⁰ See LEI Report at 14-15 (Section 1.3.5(2)).

¹¹ LEI Report at 85.

addressing those calculations. The second part of this assertion, that Skipping Stone implied “that this capacity would be available at any and all times,” requires attention as well. If the GDCs assert that they need additional pipeline capacity to meet firm demand, they would have at least two choices of approaches for securing capacity, both of which they utilize today. One would be to contract with the holders of the existing capacity on a “full-winter basis” and release the contracted capacity on days they do not need it (which they do today); or, contract with the holders of existing capacity on an “option basis” (which they do today) and call on the gas when needed. Both of these approaches are potentially more expensive than simply buying gas on a spot basis, which is another tool in their belt. Importantly, though, both of these approaches to securing capacity are more likely to be less expensive than paying year-round for as-yet unbuilt capacity. In either event, “available pipeline capacity” is converted into “reliable pipeline capacity” by contracting for the capacity (via release by another shipper to the GDC); or, by contracting for delivery of gas using the capacity.

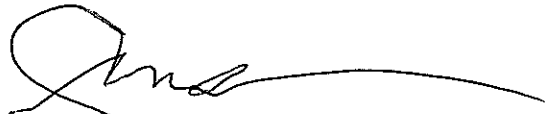
V. Board Staff Should Use These Clarifications to Inform Their Recommendations For Board Decision Making Based on the LEI Report and Resulting Gas Planning Processes

18. Based on the data and information submitted to date in this proceeding, Board Staff should recommend that the Commissioners establish a robust gas planning process to ensure that GDCs are not seeking to build or contracting to support yet-to-be built, capacity that is: (1) unneeded based on existing data showing available capacity in excess of 1 Bcfd beyond evidenced demand and more than 2.4 Bcfd beyond current GDC pipeline capacity; (2) likely to be more expensive for ratepayers than securing supply in one of the forms discussed herein; and (3) in direct conflict with Board orders defining gas energy efficiency targets, the state’s clean energy laws, the Energy Master Plan, and greenhouse gas goals and mandates.

CERTIFICATION

Gregory M. Lander, of full age, does hereby certify as follows:

1. I am President of Skipping Stone, LLC.
2. I certify that the foregoing “Verified Statement of Gregory Lander of Skipping Stone in Response to London Economics, International Report” was prepared by me or under my direction and that the statements therein true to the best of my knowledge and belief.
3. I am aware that if any of the foregoing statements made by me are willfully false, I am subject to punishment.



Gregory M. Lander

Dated: February 7, 2022