

**FINAL REPORT:  
ANALYSIS OF NATURAL GAS CAPACITY  
TO SERVE NEW JERSEY FIRM CUSTOMERS  
PUBLIC VERSION**

*Prepared for*

**New Jersey Board of Public Utilities**

*By*



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**November 5, 2021**

# Final report: Analysis of natural gas capacity to serve New Jersey firm customers

prepared for the New Jersey Board of Public Utilities by London Economics International LLC

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*London Economics International LLC (“LEI”) was engaged by the Staff of the New Jersey Board of Public Utilities (“BPU”), at the direction of the BPU, to examine the capability of current and future natural gas transmission capacity to serve gas demand from New Jersey’s local gas distribution utilities, and to determine if capacity on pipelines and from non-pipeline sources would be sufficient to ensure uninterrupted supply to all firm customers in the State through 2030. This final report covers LEI’s analysis of infrastructure, markets, demand, and non-pipeline alternatives; a review of specific reports filed in Docket No. GO19070846; LEI’s Shortfall Risk Assessment; and LEI’s Best Practices guide and Playbook for emergencies.*

*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. In the cases of extreme weather (i.e., a winter day which could be expected to occur only once in 90 years), by 2030, the system is projected to fall short by 153 thousand dekatherms per day (“MDth/d”), approximately 2.7% of current firm supply resources of 5,665 MDth/d. However, if New Jersey meets even half of its building electrification goals and/or has effective voluntary demand reduction with higher energy efficiency program targets, the shortfall risk disappears. LEI examined a variety of these non-pipeline alternatives.*

*If a large disruption of supply (of about 900 MDth/d) occurred simultaneously with design day winter conditions, a set of best practices and a playbook for responding to emergencies provide an indispensable guide to mitigate some of the danger and cost. LEI presents such a guide to Best Practices and Playbook in this report; 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.*

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# 1 Executive summary

## 1.2 Assignment and scope of work

The New Jersey Board of Public Utilities (“BPU”) engaged London Economics International LLC (“LEI”) to examine the capability of current and future natural gas transmission capacity to serve gas demand from New Jersey’s local gas distribution companies (“GDCs”), and to determine if capacity on pipelines and from non-pipeline sources would be sufficient to ensure uninterrupted supply to all firm customers in the State through 2030.<sup>1</sup>

Specifically, the assignment is to assist the BPU in determining:

- 1) if sufficient natural gas capacity exists on the regional interstate pipeline system to meet the future peak day demand forecasts of New Jersey’s GDCs; and
- 2) if there will be sufficient capacity through 2030 to ensure uninterrupted supply to all firm natural gas customers in New Jersey.

The engagement is a component of BPU Docket No. GO19070846 – In the Matter of the Exploration of Gas Capacity and Related Issues.

The engagement is focused on the reliability of the gas system to meet firm demand. A reliability study is in contrast to an economic study which would include an examination of gas prices at traded hubs, or the cost of various sources of gas supply.

Topics addressed by LEI were:

- A review of gas transmission and delivery infrastructure and projections of peak demand (covered in Section 2.1 of this report);
- A review of the market structure of natural gas, including contracting options and the profile of interruptible customers (covered in Section 2.2);
- A review of gas demand outlooks and, and development of demand forecasts through 2030 (Section 2.3);
- A review of non-pipeline alternatives (Section 2.4);
- A review of two reports filed in proceedings related to the Order in Docket No. GO19070846 dated February 27, 2019: 1) Levitan and Associates (“Levitan Report”) filed by New Jersey Natural Gas,<sup>2</sup> and 2) affidavit of Greg Lander, President of Skipping Stone

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<sup>1</sup> Board of Public Utilities Request for Engagement Response State Term Contract T-2000 Energy Consulting Services, for Consulting and Analysis for Natural Gas Capacity (referred to as “RFP”).

<sup>2</sup> Levitan & Associates, Inc. Availability of Natural Gas Capacity to Meet New Jersey LDC Customer Needs. Prepared for New Jersey Natural Gas. July 12, 2019.



(“Skipping Stone Affidavit”) filed by the Environmental Defense Fund (“EDF”) and the New Jersey Conservation Fund (“NJCF”) together EDF/NJCF<sup>3</sup> and (Section 3);

- An assessment of the risk of a supply shortfall through 2030, and a robust set of mitigation measures (Section 4); and
- Identification of best practices and playbook for managing supply shortfall emergencies (Section 5).

## 1.3 Key findings and insights

### 1.3.1 Infrastructure and peak demand

A huge natural gas production region, the Marcellus Shale, is located on New Jersey’s doorstep. The Marcellus shale in Pennsylvania and demand centers in the State are both components of an integrated US-wide market for gas, with supply regions and demand centers interconnected by a well-established system of gas transportation and distribution pipelines and storage areas.

LEI’s key findings related to infrastructure and demand for New Jersey show that:

- **capacity on interstate gas pipelines** to bring gas into New Jersey increased somewhat faster than gas transportation capacity out of New Jersey from 2010 to 2019;
- **gas consumption growth** in the State has been driven mostly by the electric power and industrial sectors, which do not typically contract for firm gas delivery. Over the ten years through 2019, New Jersey’s natural gas consumption grew at a compounded annual growth rate (“CAGR”) of 1.8%; this was driven by electric power consumers (4.6% CAGR) and industrial customers (3.1% CAGR); and
- **most natural gas usage occurs during the winter**, driven by residential usage for heating. About 75% of New Jersey households rely on natural gas to heat their homes.<sup>4</sup> Consumption growth among residential customers was slower than the overall growth rate at 1.0% CAGR, and consumption from commercial customers actually declined. Weather-normalized historical peak demand grew 0.95% annually over the past five years.

Residential consumption for heating during the coldest months of the year, usually January or February, drives the winter peak in total demand. These winter peaks are important because the gas delivery system (interstate pipelines, distribution pipelines, and gas storage) must be designed to meet such peaks, rather than average annual consumption.

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<sup>3</sup> Lander, G. BPU Docket No. GO19070846. Attachment to EDF/NJCF Comments. Expert Affidavit of Gregory M Lander. Exhibit GL-2. October 2019  
<[https://publicaccess.bpu.state.nj.us/CaseSummary.aspx?case\\_id=2108126](https://publicaccess.bpu.state.nj.us/CaseSummary.aspx?case_id=2108126)>.

<sup>4</sup> US Energy Information Administration. *New Jersey: State Energy Profile*. Updated: September 17, 2020.

### 1.3.2 Market structure: How GDCs meet firm demand

The State's four GDCs (Elizabethtown Gas, New Jersey Natural Gas, Public Service Electric and Gas, and South Jersey Gas) are required to provide safe, adequate, and proper gas services at reasonable rates for the customers they serve.<sup>5</sup> The GDCs' Basic Gas Supply Service ("BGSS") filings include five-year forecasts of design day demand – i.e., the demand expected by each GDC on the coldest day of the year. To meet this forecasted design day demand, the GDCs generally rely on the following gas supply resources:

- **firm transportation ("FT") contracts with gas pipelines:** GDCs contract for firm gas transportation capacity on interstate natural gas pipelines serving New Jersey. FT is a guarantee that capacity will be available when the GDCs call upon it, so GDCs rely on FT to serve their customers reliably. FT contracts enable GDCs to have first call on pipeline capacity, with priority service to primary receipt and delivery points. These contracts are usually for terms of many years, so the GDCs can be confident that they can rely on this capacity year after year;
- **access to storage:** GDCs hold storage contracts to balance gas supply with demand throughout the year, as well as to meet shorter-term fluctuations in demand;
- **on-system peak-shaving capabilities:** GDCs own and operate liquefied natural gas ("LNG") peaking facilities to provide back-up supplies during extreme weather conditions; and
- **off-system peak shaving contracts:** GDCs contract with suppliers for bundled commodity and transportation to meet peak demand. These contracts are often short-term in nature (one season or a few seasons), so there is a risk that the contracts might not be available in the future.

In addition to serving firm customers, New Jersey's GDCs also supply interruptible customers. Customers under an interruptible service tariff receive gas service only if available. As such, they are subject to curtailment or interruption if the GDC requires the supply to serve firm customers.

New Jersey also allows customers to buy gas from a provider other than their GDC (i.e., a licensed third-party supplier ("TPS")).<sup>6</sup> TPSs generally deliver gas to the GDCs' city gates, which GDCs are then responsible for transporting to customers. Gas delivered by TPS to customers participating in retail choice peaked in 2012 for commercial customers and 2013 for residential customers; it essentially leveled off at about the same time for industrial customers. In 2019, 4% of residential customers, 55% of commercial customers, and 94% of industrial customers were such retail choice customers. Across all customer classes, retail choice deliveries in 2019 accounted for around 20% of total deliveries made by GDCs in the state. Some of these retail choice customers, particularly commercial and industrial customers, are likely to be on interruptible tariffs.

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<sup>5</sup> NJ BPU. [About NJBPU](#).

<sup>6</sup> NJ Power Switch. [Know Your Rights](#).

It is not transparent how much third-party supply is matched to FT contracts. In a situation of peak demand and limited transportation capacity, based on available information, LEI cannot determine if TPSs have enough FT capacity to meet their firm demand.

### 1.3.3 Design day demand to 2030 will decline only if building electrification gets under way

Projections for design day firm gas demand in New Jersey provide the foundation for GDC capacity needs. Design day firm demand is the gas sendout that a GDC expects to have to provide during an extremely cold day, to its firm (non-interruptible) customers; it is the demand that the system is designed to meet. Each New Jersey GDC defines its design day criteria in a similar, but not identical, manner. For the coming decade, design day firm demand is likely to be impacted by energy efficiency requirements and targets. LEI examined historical trends and developed two sets of design day demand scenarios from 2021 to 2030.

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. First, it is not based on the historical trend in demand per HDD of 0.95% CAGR annually. Second, two GDCs, NJNG and ETG, assume efficiency will not improve in the future relative to the past. And third, two GDCs rely on customers switching from oil to natural gas for a portion of demand growth, even though this practice is likely to slow given public policies which encourage electrification rather than switching to natural gas heating. LEI developed alternative scenarios of design day firm demand, which reflect historical trends in demand per HDD, and New Jersey clean energy programs going forward.

In compliance with the State's Clean Energy Act ("CEA"), the Board Order requires each GDC to reduce the use of natural gas *below what would have otherwise been used*.<sup>7</sup> The phrase "would have otherwise been used" implies a counterfactual must be created to use as a benchmark – the counterfactual establishes the energy consumption that would have occurred without the efficiency efforts.

LEI defined the counterfactual as the outlook for design day firm gas demand growth without the impact of new efficiency efforts or building electrification. If based on an actual historical perspective, this counterfactual outlook is 0.95% demand growth per year. LEI used this underlying 0.95% counterfactual growth as the basis of a set of Scenarios which encompass five different assumptions about the impact of energy efficiency targets on peak demand. LEI also used the GDC's outlook of 1.02% growth as the basis for another set of peak demand Scenarios.

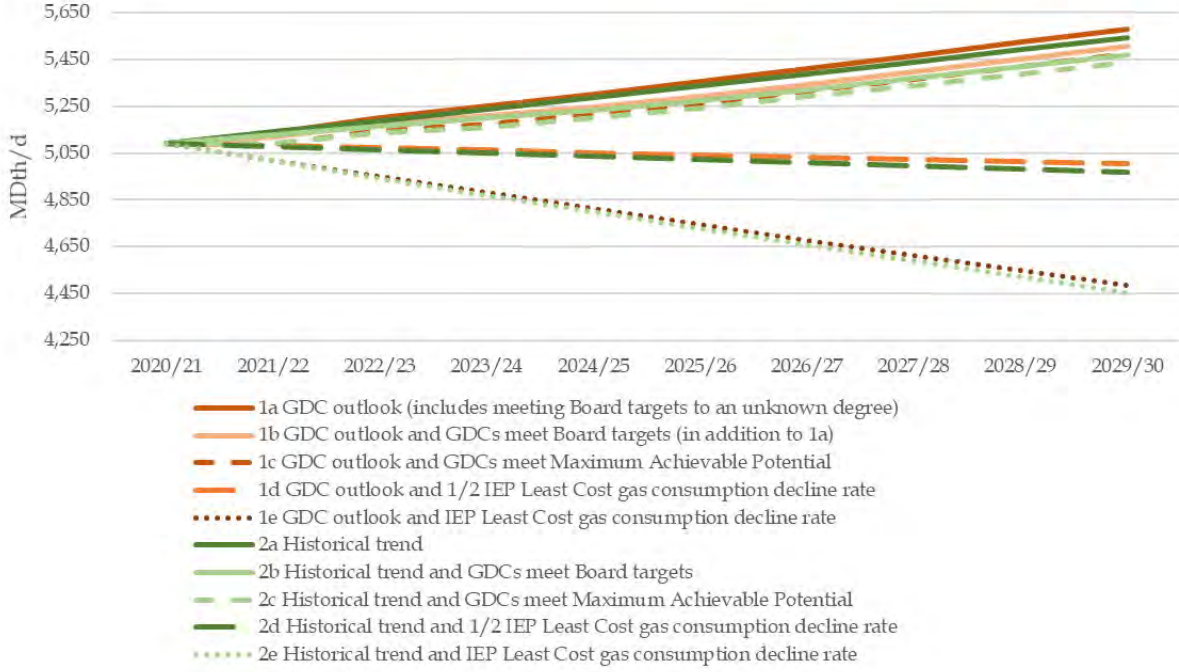
Whether LEI's 0.95% growth or the GDC's 1.02% growth is used as the counter-factual, the largest differences in the Scenario outlooks by 2030 reflect differences in assumptions about building electrification (i.e., fuel-switching from gas to electric space and water heating) (see Figure 1). The only Scenarios in which peak gas demand declines are 1d, 1e, 2d, and e2. The "d" Scenarios posit building electrification at ½ the Energy Master Plan (EMP) Integrated Energy Plan ("IEP")

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<sup>7</sup> NJ BPU. *Order Directing the Utilities to Establish Energy Efficiency and Peak Demand Reduction Programs* (Docket Nos. QO19010040, QO19060748, and QO17091004). June 10, 2020. p. 30.

least-cost case gas consumption decline rate. The “e” Scenarios posit the full EMP IEP least cost case gas consumption decline rate.

**Figure 1. LEI scenarios for design day firm demand**



Scenario	CAGR outcomes from 2020/21 to 2029/30
<b>Set one</b>	
1a GDC outlook (includes meeting Board targets to an unknown degree)	1.02%
1b GDC outlook and GDCs meet Board targets (in addition to 1a)	0.87%
1c GDC outlook and GDCs meet Maximum Achievable Potential	0.81%
1d GDC outlook and 1/2 IEP Least Cost gas consumption decline rate	-0.20%
1e GDC outlook and IEP Least Cost gas consumption decline rate	-1.42%
<b>Set two</b>	
2a Historical trend	0.95%
2b Historical trend and GDCs meet Board targets	0.80%
2c Historical trend and GDCs meet Maximum Achievable Potential	0.74%
2d Historical trend and 1/2 IEP Least Cost gas consumption decline rate	-0.27%
2e Historical trend and IEP Least Cost gas consumption decline rate	-1.49%

If there is no building electrification at all, design day demand will grow, albeit at a slower rate than in the past.

### **1.3.4 Non-pipelines alternatives on the demand side are more consistent with state goals than supply-side alternatives**

Non-pipeline solutions (or non-pipeline alternatives) are means of reliably meeting natural gas demand that offset, defer, or avoid the need for new pipeline capacity. LEI's research shows that gas distribution companies in the United States have implemented non-pipeline alternatives ("NPAs") from the demand-side and supply-side:

- **demand-side:** These programs reduce natural gas demand from the customer-side of the meter and include energy efficiency ("EE") improvements, demand response ("DR") programs, targeted electrification, and innovative rate designs.
- **supply-side:** These programs/investments increase the supply of natural gas or alternative fuels, such as renewable natural gas ("RNG"), green hydrogen, liquefied natural gas ("LNG"), or compressed natural gas ("CNG"), which can be injected into the pipeline system to meet customer demand.

NPAs vary in terms of their stage of development and deployment, ranging from solutions that have been implemented in the United States for over two decades (i.e., energy efficiency programs) to solutions that are still in an early stage of development (e.g., green hydrogen).

Finally, NPAs can also be categorized by their ability to either address peak day demand (the focus of programs such as demand response, or LNG and CNG supplies) or overall annual consumption of gas (energy efficiency, building electrification).

Through discussion with BPU Staff, LEI developed a list of goals against which each of the NPAs could be scored, namely:

- improve reliability and resiliency;
- within the Board's control;
- build upon current capabilities;
- consistent with state goals and policies;
- cost-effective;
- enable social equity;
- technically feasible; and
- implement within a suitable timeframe.

While some of these goals might reinforce one another, others might be mutually exclusive, or at least require trade-offs. Based on the goals, and the scoring system used by LEI, energy efficiency scored the highest of the NPAs, while green hydrogen and LNG/CNG scored the lowest (see Figure 2). Overall, demand-side NPAs scored higher than supply-side NPAs.

**Figure 2. NPAs scored against BPU goals**

Criteria	Non-pipe mitigation option							
	Energy efficiency	Voluntary DR program	Direct load control DR	Building electrification	RNG	Green hydrogen	LNG/CNG trucking	Advanced leak detection
Improve reliability/resilience	Yes	Yes	Yes	Somewhat*	Yes	Yes	Yes	Yes
Under the Board's control	Yes	Yes	Yes	Yes	No	No	No	Somewhat
Build upon current capabilities	Yes	Yes	Yes	Somewhat	No	No	No	Somewhat
Consistent with state climate targets	Yes	Somewhat**	Somewhat**	Yes	Yes	Yes	No	Somewhat
Cost effective	TBD							
Enable social equity	Yes	n/a	n/a	Yes	n/a	n/a	n/a	n/a
Technically feasible	Yes	Yes	Yes	Yes	Somewhat	No	Somewhat	Somewhat
Suitable lead time	Yes	Yes	Yes	No	Somewhat	No	Somewhat	Yes
<b>Overall score</b>	<b>7</b>	<b>5.5</b>	<b>5.5</b>	<b>5</b>	<b>3</b>	<b>2</b>	<b>2</b>	<b>4</b>

\* Electrification arguably decreases the resiliency of the electric and gas system as a whole, because it increases the proportion of heating needs in the state met by one energy source (i.e., electricity), reducing the diversity in supplies for heating needs. On the other hand, it frees up gas that would be used for space heating to be used in electricity generation, so it could be argued that it increases resilience.

\*\* Voluntary DR and direct load control programs are scored as being “somewhat” consistent with state climate targets, because the outcome depends on the replacement fuel being used to meet heating needs. For instance, if customers turn down the thermostat on their gas furnaces and then heat their home with an oil-fired or wood-burning furnace instead, it would not reduce carbon emissions and hence not be consistent with state climate goals.

Note: Overall scores are based on the number of criteria met with a “Yes” (1 point) or “Somewhat” (0.5 point), or “No” (0 points). Higher scores indicate a higher or better rank relative to other NPAs.

### 1.3.5 Proceedings reports presented extreme views about availability of natural gas capacity

The Order in Docket No. GO19070846 dated February 27, 2019 (“February 2019 Order”) directed exploration of whether there is sufficient gas capacity to meet New Jersey customer needs.<sup>8</sup> In this process, NJNG filed the Levitan Report, and EDF/NJCF filed the Skipping Stone Affidavit.

The Levitan Report warned that New Jersey GDCs would be short of design day requirements very soon – by 2022/23. The Skipping Stone Affidavit argued the opposite – that a huge amount (over 1,000 MDth/d) of pipeline capacity is additionally available to New Jersey GDCs.

The key differences in the reports are:

- 1) **the way in which the Levitan Report and Skipping Stone Affidavit treated non-GDC pipeline capacity:** Levitan assumed gas pipeline capacity is available to NJ GDCs only if it is under FT contract to the GDC or controlled by a producer/marketer with primary delivery points in New Jersey. The Skipping Stone Affidavit argued that large volumes of non-NJ GDC capacity contracts which pass through New Jersey should be counted as available to the NJ GDCs, even if the primary delivery point is not in New Jersey.
- 2) **the Levitan Report addressed reliability, i.e., what happens during design day, capacity-constrained periods; the Skipping Stone Affidavit ignored what happens during capacity-constrained periods:** The Levitan Report referred to GDC design day

<sup>8</sup> New Jersey BPU Staff. Notice: Docket No. GO19070846, “In the Matter of the Exploration of Gas Capacity and Related Issues.” September 10, 2019. <[https://publicaccess.bpu.state.nj.us/CaseSummary.aspx?case\\_id=2108126](https://publicaccess.bpu.state.nj.us/CaseSummary.aspx?case_id=2108126)>

firm demand and compared it to two categories of supply sources (pipeline and peaking capacity) available to meet the demand. The Skipping Stone Affidavit referred to historical peak demand, which for the GDCs is less than design day firm demand, but also included demand from other users such as power generators; and referred only to pipeline capacity as a source of supply. Because the Skipping Stone Affidavit discussed neither design day demand nor sources of firm supply, conclusions do not shed light on reliability.

- 3) **they addressed demand differently, though neither report examined gas demand in a thorough way:** The Levitan Report took the GDCs' design day firm demand forecasts at face value, and did not examine the degree to which the demand forecasts reflected New Jersey's Energy Master Plan and other efficiency and energy policy targets. The Skipping Stone Affidavit did not address reliability, instead, it relied on historical peak day demand rather than design day firm demand in its analysis.

The Levitan Report's underlying message is that the only way to address a shortfall in firm supply is by expanding pipeline capacity; it did not consider any non-pipeline alternatives. The Skipping Stone Affidavit argued for non-pipeline alternatives, which is consistent with State efficiency goals. But as a reliability study, it missed the point on demand.

LEI's analysis (detailed in Section 4 and summarized next in Section 1.3.6) shows that neither the Levitan Report's looming crisis nor Skipping Stone's substantial unused pipeline capacity are reasonable planning projections.

### **1.3.6 Shortfall Risk Assessment shows low risk of serious shortfalls**

The key findings of LEI's analysis of potential shortfalls are that, yes, under the most likely set of future outcomes, sufficient natural gas capacity exists on the regional interstate pipeline system to meet the future peak day demand forecasts of New Jersey's GDCs. The interstate system is the main source for firm supply on peak days for the GDCs, but it is not the only source. For this likely set of outcomes, there will be sufficient capacity (pipelines, storage, plus other peaking supplies) through 2030 to ensure uninterrupted supply to all firm natural gas customers in the State. This more likely set of outcomes includes three conditions: normal winter demand, historical peak winter demand, and design day winter demand (see Figure 3).

Only in a situation of extremely high demand (for example, winter weather which would be expected to occur one day in 90 years), or in the case of a large pipeline outage, would the system fall short. To summarize these findings of LEI's Shortfall Risk Assessment:

- **High probability outcomes:** By 2030, New Jersey firm gas customers are not likely to experience a shortfall in gas supply on a **Normal Winter Day**, or even a day with weather similar to historical cold-weather events, referred to as an **Historical Peak Day**). There would be a surplus gas capacity of 3,196 MDth/d in a normal winter. The term "surplus" does not mean gas supplies are being wasted, or that the pipeline transportation system is over-built. As discussed below in Section 2, a gas supply system is scaled to ensure reliability on a peak demand day, aka design day (explained in more detail below). A design day requires much more supply capacity than a typical or even colder-than-normal demand day.

Figure 3. Shortfall Risk Assessment

Conditions (2029/30)	Total firm demand (MDth/d)	Surplus or shortfall (MDth/d)
<b>High probability, low impact</b>		
Normal Winter Day	2,547	3,196
Historical Peak Day	3,967	1,776
<b>Low probability, moderate impact</b>		
Winter Design Day	5,469	274
<b>Lower probability, higher impacts</b>		
1-in-90 Design Day	5,896	-153
Perfect Storm (2026/27)	5,321	-525

- Lower probability outcome, with moderate impact:** New Jersey firm gas customers, are not likely to experience a shortfall in gas supply by 2030, even on a **Winter Design Day**. A Winter Design Day is a planning condition with firm demand typically about 35% higher than historical peak demand (in other words, about double normal demand). Assuming LEI’s Scenario 2b (with 0.80% annual growth in gas demand, as discussed in detail in Section 2.3), LEI estimates there would be 274 MDth/d to spare by 2030. Supplies of 274 MDth/d are not a trivial volume. They amount to about the whole of Elizabethtown Gas’ firm gas demand on the coldest winter days of the past five years. Scenario 2b assumes, conservatively, that no progress is made on building electrification efforts over the next decade.
- Low probability outcome with potentially high impact:** A **1-in 90 Design Day** (defined as a level of firm demand which is very high and could be expected to occur only once in 90 years), and assuming LEI’s Scenario 2b, a supply shortage of 153 MDth/d could occur by 2030. This is large enough to be considered an Orange-Alert emergency as defined by LEI in Section 5, where best practices are outlined in conjunction with a Playbook to address shortfalls. LEI views this as a predictable shortfall and addresses ways to position the system to fill the gap using a portfolio of NPAs (reviewed in Section 2.4).
- Low probability outcome with potentially very high impact:** A pipeline outage which occurs during a Winter Design Day and is assumed to impact half the capacity on the Transco pipeline is characterized by LEI as a **Perfect Storm** (modeled as randomly occurring in 2026/27, though the occurrence could be in any year). This could lead to a large shortfall of 525 MDth/d, equivalent to 20% of the firm gas demand needed in a normal winter. LEI categorizes this as a Red-Alert emergency, and strategies to deal with this are discussed in the Playbook in Section 5.

To mitigate against low probability but high impact outcomes, the BPU should consider implementing a combination of non-pipeline alternatives, which can be ranked and prioritized according to their ability to meet various goals, such as improving system reliability or resiliency, consistency with state policies and targets, and/or cost-effectiveness.



Other key insights from the Shortfall Risk Assessment are:

- The LEI scenarios for **design day firm demand growth** (eight scenarios, divided into two sets based on assumed underlying demand growth and defined by varying levels of future energy efficiency) indicate that the **only future scenarios where gas demand declines are ones in which some amount of building electrification occurs**. Without building electrification, gas demand growth will slow as energy efficiency programs ramp up, but growth will still be positive, as discussed in Section 2.3.

**Building electrification could have a substantial impact.** If even half the target of the New Jersey's EMP IEP Least Cost target (which assumes building electrification and other programs reduce pipeline gas consumption by 2.44% from 2020 to 2030) is met, it would obviate the need for an estimated 576 MDth/d of gas supply by 2030.<sup>9</sup> This on its own would eliminate LEI's projected supply shortfall under the 1-in-90-years winter demand condition.

### 1.3.7 Best practices and playbook provide plans to cope with low-probability, high impact events

Though shortfall conditions are less likely to occur than surplus conditions, this does not mean that New Jersey should be unconcerned about meeting firm demand for natural gas. Design day firm demand is the reliability planning standard that the NJ GDCs must meet, and that consumers expect the BPU to ensure. Beyond that standard, the BPU and GDCs need a playbook for coping with scenarios of extreme weather and the possibility of a large accident or outage.

LEI identified best practices based on lessons learned from other jurisdictions faced with energy emergencies, and took into account New Jersey's starting point, so that the recommended practices build upon processes already in place in New Jersey. Best practices are:

- **Develop rules, as they are more reliable than recommendations.** Development of enforceable rules (either for actions and processes which can prevent emergencies, or actions and processes to use during emergencies) may require stakeholder consultation and input, and therefore take longer to develop than recommendations. However, without formalization, New Jersey risks finding itself in a situation whereby significant disruption occurs despite policymakers and first responders having the knowledge and expertise to prevent them. This lesson was learned the hard way in Texas in February 2021;
- **Focus on strategies under the BPU's control:** Demand-side measures, incentives, and penalties in the context of the regulatory regime, and communications are all under the control or direct influence of the BPU;

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<sup>9</sup> New Jersey 2019 IEP Technical Appendix, Evolved Energy Research. November 29th, 2019. P. 45-46. The 2.44% decline is for annual gas consumption, not peak day consumption. LEI assumes the impact on peak day consumption is equivalent, because heating equipment and building characteristics have a large impact on gas demand for heating, which in turn is the majority of firm gas demand in the winter.

- **Build on existing platforms:** Expanding on the current communications protocol has low marginal costs because the communications system has already been built, so modifying it will take little lead time and be relatively low cost;
- **Begin now:** Make sure the tools and infrastructure are in place, so that when disaster strikes, the plans that depend on the tools can be implemented.

The Playbook discusses strategies for responding to three levels of supply shortfall. In summary, they are:

- **Elevated (Yellow) Alert:** Potential Winter Design Day conditions, where, while no shortfall of supply is necessarily predicted, customers would be encouraged to conserve gas;
- **Critical (Orange) Alert:** Potential 1-in-90 Design Day conditions with a shortfall of up to about 150 MDth/d. Assuming all NPAs are in place, there would be no need for direct load control; however, if NJ is aware that NPAs have not reached target levels, then the State needs to be ready to implement direct load control. Minimal direct load control (1-3 degrees on average for all firm customers) would be implemented to make up for any shortfall in the other NPAs; and
- **Emergency (Red) Alert:** LEI defines a Red Alert as a condition which involves the need for substantial direct load control, such as a Perfect Storm, combining a Winter Design Day and a 900 MDth/d outage on a major pipeline, for a shortage of 525 MDth/d. Direct load control would be evoked, and effective coordination by the BPU may minimize the impact on customers. The Governor's Office and others would be involved in communications.

As will become clear in the Playbook, New Jersey will have the capability to withstand even large natural gas supply shortfalls, if it plans ahead.

## **1.4 Roadmap for the report**

The report begins with a description of natural gas infrastructure and markets (Section 2), which comprise the playing field in which gas demand is met by gas supply. The section also presents two sets of scenarios for firm gas demand to 2030 developed by LEI, which reflect varying assumptions about underlying demand growth and energy efficiency trends. The section closes with a review of NPAs for meeting gas demand, in which LEI examines the programs in place in other jurisdictions and the state of progress with NPAs in the State.

Section 3 covers LEI's analysis of two reports filed in Docket No. GO19070846,<sup>10</sup> namely: a report authored by Levitan and Associates ("Levitan Report") and filed by New Jersey Natural Gas ("NJNG"); and an affidavit authored by Greg Lander of Skipping Stone ("Skipping Stone Affidavit"), filed by the Environmental Defense Fund/New Jersey Conservation Fund. LEI

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<sup>10</sup> New Jersey BPU Staff. Notice: Docket No. GO19070846, "In the Matter of the Exploration of Gas Capacity and Related Issues." September 10, 2019.

assessed the extent to which each of the reports provides useful insights into potential future shortfalls in gas supply and options to meet these shortfalls.

Section 4, the Shortfall Risk Assessment, uses the foundation of LEI's scenario outlooks and profiles of NPAs to examine the scale of shortfalls, and the options for meeting shortfalls to 2030.

Section 5, the Best Practices and Playbook for emergencies, outlines specific approaches to coping with extreme weather and/or supply disruptions. While the probability of such emergencies might be low, LEI's findings indicate that preparation is key. The tools that need to be developed and the consensus required to do so should be addressed as soon as possible.

Appendix 1 (Section 6) "Supplying natural gas to New Jersey" is referred to in Section 2 and provides background to support the reader's understanding of the gas pipeline system which serves the New Jersey GDCs.

Appendix 2 (Section 7) "Lessons learned from recent disasters" is referred to in Section 5 and provides details of several emergency events which impacted gas systems in New Jersey and elsewhere.

#### **Useful equivalencies**

Dekatherms ("Dth") and British thermal units ("Btu") are measures of energy content. One Dth is equal to one million British thermal units ("MMBtu").

Cubic feet are measures of volume. One thousand cubic feet (Mcf) of gas is generally equivalent to 1.037 MMBtu, or 1.037 Dth.

## 1.5 List of acronyms

AGF	American Gas Foundation
ALD	Advanced Leak Detection
APS	Alternative Portfolio Standard
BBtu	Billion British thermal units
BCA	Benefit-cost Analysis
BGSS	Basic Gas Supply Service
Btu	British thermal unit
C&I	Commercial and Industrial
CAGR	Compound Annual Growth Rate
CEA	Clean Energy Act
CEF-EE	Clean Energy Future – Energy Efficiency Program
CIP	Conservation Incentive Program
CN	Certificate of Need
CNG	Compressed Natural Gas
CO <sub>2</sub> e	Carbon dioxide equivalent
ConEd	Consolidated Edison, Inc.
CP	Capacity Performance
CPUC	California Public Utilities Commission
DCE	Division of Clean Energy
DDC	Design Day Condition
DIMP	Distribution Integrity Management Program
DR	Demand Response
Dth	Dekatherm
EDECA	Electric Discount and Energy Competition Act
EDF	Environmental Defense Fund
EE	Energy Efficiency
EEA	Energy Emergency Alert Level
EIA	Energy Information Administration
EMP	Energy Master Plan
ENDURE	Elizabethtown Natural Gas Distribution Utility Reinforcement Plan
ESAM	Energy Strong Adjustment Mechanism
ETG	Elizabethtown Gas
FAA	Federal Aviation Administration
FERC	Federal Energy Regulatory Commission
FT	Firm Transmission
GDC	Gas Distribution Company
HDD	Heating Degree Day

HH	Hybrid Heat
IEP	Integrated Energy Plan
II&R	Infrastructure Investment and Recovery Regulations
IIP	Infrastructure Improvement Program
IRENA	International Renewable Energy Agency
IT	Interruptible Transportation
LAUF	Lost and Unaccounted-for Gas
LDC	Local Distribution Company
LEI	London Economics International LLC
LNG	Liquefied Natural Gas
LOLP	Loss of Load Probability
LPA	Liquified Propane Air
MA DOER	Massachusetts Department of Energy Resources
MassCEC	Massachusetts Clean Energy Center
Mcf	Thousand cubic feet
Mcf/d	Thousand cubic feet per day
MMcf/d	Million cubic feet per day
MDQ	Maximum Daily Quantity
MDth	Thousand dekatherms
MDth/d	Thousand dekatherms per day
MMBtu	Million British thermal units
MMT	Million Metric Tons
MOU	Memorandum of Understanding
NARUC	National Association of Regulatory Utility Commissioners
NCEI	National Centers for Environmental Information
NJ BPU	New Jersey Board of Public Utilities
NJ CEP	New Jersey Clean Energy Program
NJ RISE	New Jersey Reinvestment in System Enhancements
NJ ROIC	New Jersey Regional Operations and Intelligence Center
NJ SEOC	New Jersey State of Emergency Operations Center
NJCF	New Jersey Conservation Fund
NJNG	New Jersey Natural Gas
NJR	New Jersey Resources
NOAA	National Oceanic and Atmospheric Administration
NPA	Non-pipeline Alternative
NY DPS	New York Department of Public Service
NY PSC	New York Public Service Commission
OBRP	On-bill Repayment Program

OFO	Operational Flow Order
P2G	Power-to-gas
PHMSA	Pipeline and Hazardous Materials Safety Administration
PJM	PJM Interconnection
PSE&G	Public Service Electric and Gas
PY	Program Year
R&D	Research and Development
RFP	Request for Proposal
RGGI	Regional Greenhouse Gas Initiative
RNG	Renewable Natural Gas
RTO	Regional Transmission Organization
SHARP	Storm Hardening and Reliability Program
SJG	South Jersey Gas
SJI	South Jersey Industries
SoCalGas	Southern California Gas Company
SRL	Southern Reliability Link
TBtu	Trillion British thermal units
Tetco	Texas Eastern Transmission
TGP	Tennessee Gas Pipeline
TOU	Time-of-use
TPS	Third-party Supplier
Transco	Transcontinental Gas Pipeline

## 2 Analysis of infrastructure, markets, demand, and non-pipeline solutions

LEI's key findings related to infrastructure, markets, demand, and non-pipeline alternatives are detailed in this section. At a high level, they are:

- capacity on interstate **gas pipelines** to bring gas into New Jersey increased somewhat faster than transmission out of New Jersey from 2010 to 2019, for a gain of 466 MDth/d;
- **gas consumption growth** in New Jersey has been driven mostly by the electric power and industrial sectors, which do not typically contract for firm gas delivery;
- gas delivered by **third-party suppliers** ("TPS") to customers participating in retail choice peaked in 2012 for commercial customers and 2013 for residential customers; it essentially leveled off at about the same time for industrial customers. It has not been growing;
- **weather-normalized historical peak demand** grew 0.95% annually in New Jersey over the past five years;
- for the purposes of conducting the Shortfall Risk Assessment (Section 4), LEI recommends using a **demand outlook scenario** which reflects the historical peak demand growth of 0.95% and the minimum efficiency gains required by the New Jersey Board of Public Utilities Order (Docket Nos. QO19010040, QO19060748, and QO17091004) of June 10, 2020 (referred to as the "Board Order") (and including LEI assumptions projecting the efficiency gains from 2025 to 2030). This results in **projected design day firm demand growth of 0.80% annually**, and a projected design day demand in 2030 which is 377 MDth/d higher than in 2020; and
- for NPAs, LEI recommends a **portfolio of approaches** to meeting demand shortfalls, which includes voluntary (incentivized) demand response, several supply-side alternatives, and direct load control in the case of emergencies on the scale discussed in Section 5.

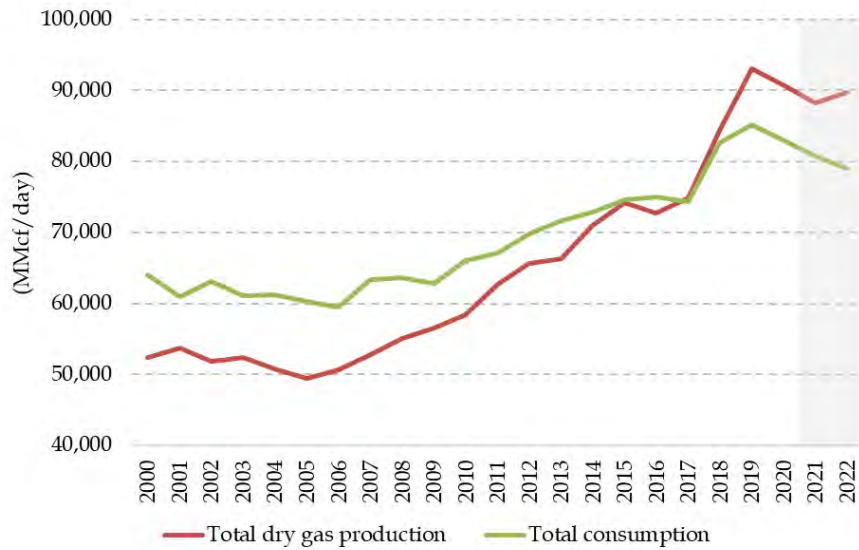
### 2.1 Gas transmission and delivery infrastructure

Natural gas is plentiful in the United States, with a huge production area, the Marcellus Shale, located on New Jersey's doorstep. The large shale plays have driven up annual US dry gas production in recent years (see Figure 4). The US-wide trend in abundant gas supply is important to New Jersey, because the country is a single integrated market for gas, with supply regions and demand centers interconnected by a well-established system of gas transmission pipelines and storage areas.

#### 2.1.1 Pipeline capacity into New Jersey increased faster than capacity out of New Jersey

Though natural gas is abundant in the United States and, as noted above, much of this gas is produced close to New Jersey in neighboring Pennsylvania, access to this gas depends on the capacity of pipelines to deliver it into the state. Likewise, for many New York and New England customers, access to gas depends on capacity out of New Jersey.

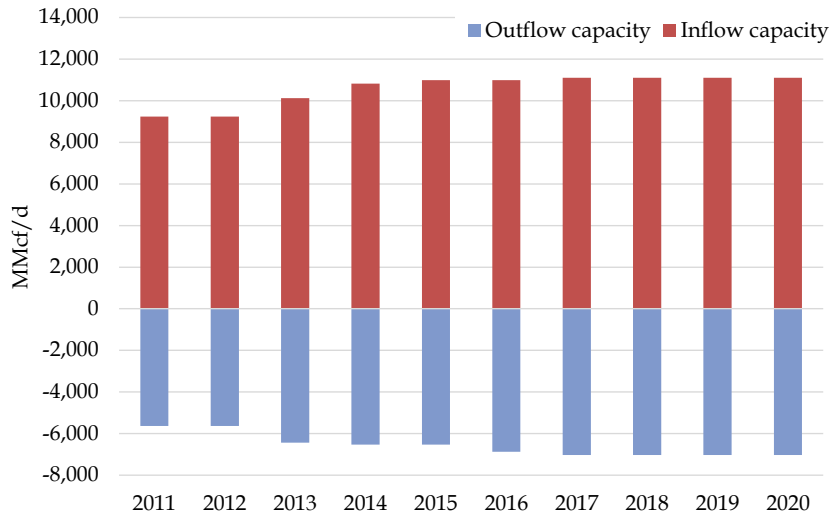
Figure 4. US historical natural gas supply and consumption and outlook to 2022



Source: Energy Information Administration. *Short-Term Energy Outlook (STEO)*. January 12, 2021. <https://www.eia.gov/outlooks/steo/>

Pipeline capacity into New Jersey increased from 9,234 MMcf/d in 2011 to 11,097 MMcf/d in 2020 (see Figure 5). Capacity out of New Jersey grew from 5,629 MMcf/d to 7,026 MMcf/d for the period. The net effect is that the State had a net gain of inflow capacity of 466 MMcf/d.

Figure 5. Total interstate pipeline capacity into and out of New Jersey (MMcf/d)



	Inflow capacity	Outflow capacity	Net
2011	9,234	-5,629	3,605
2020	11,097	-7,026	4,071
Diff	1,863	-1,397	466

Source: Energy Information Administration. *Natural Gas data: State to State Capacity*. Release date: January 2021.



Since 2018, at least five new projects added about 735 Mcf/d of additional capacity into New Jersey. These include three expansions by Transcontinental Gas Pipeline (“Transco”), and one expansion and one lateral addition by Texas Eastern Transmission Company (“Tetco”) that were all completed in the last three years (see Figure 6). In addition, New Jersey Natural Gas (“NJNG”) expects the completion of its Southern Reliability Link (“SRL”) in 2021, which has a capacity of about 180 Mcf/d.

**Figure 6. New gas pipelines in New Jersey**

Project Name	Project Operator	Project Type	In-Service Date	Additional capacity (MMcfd)	Demand served
Bayway Lateral Project	Texas Eastern Transmission	Lateral	2018	300	Refinery and cogeneration plant
Garden State Expansion Phase 2	Transcontinental Gas Pipeline	Expansion	2018	120	GDC (NJNG)
Lambertville East Expansion Project	Texas Eastern Transmission	Expansion	2019	60	GDC
Rivervale South to Market Project	Transcontinental Gas Pipeline	Expansion	2019	190	Regional demand
Gateway Expansion Project	Transcontinental Gas Pipeline	Expansion	2020	65	Replacement of valves, compressors, and associated equipment to improve deliverability
Southern Reliability Link	New Jersey Natural Gas	Interconnection	2021*	180	GDC system reliability

\*NJNG’s Southern Reliability Link is still under construction, but the GDC expects it will come online in 2021.

Source: Energy Information Administration. *US natural gas pipeline projects*. Release date: January 2021.

The PennEast Pipeline, a 118-mile project whose investors had include Enbridge as well as the New Jersey GDCs, began development in 2014, but the project was cancelled 2021 (see text box). As discussed in Section 4, the Shortfall Risk Assessment, LEI did not assume that PennEast was in operation (based on the GDC’s projections of sources of firm capacity, which exclude their agreements with PennEast). If it were, there would be little to no shortfall in meeting firm demand even during extreme weather such as a 1-in-90 years winter through 2030, and therefore little need to examine non-pipeline alternatives for reliability.

### PennEast pipeline project

The PennEast project was proposed as an approximately 118-mile, 36-inch diameter pipeline from Luzerne County, Pennsylvania to Mercer County, New Jersey. The project experienced lengthy regulatory delays, at both the state and federal levels.

The project developers initially filed for a certificate from the Federal Energy Regulatory Commission (“FERC”) in 2015, for 1,107 MDth/d and a route that included delivery points in New Jersey. Though FERC eventually approved the whole project in 2018, the project ran into complications getting permission to site the line in New Jersey. For that reason, PennEast filed a petition in January 2020 asking FERC for permission to proceed with Phase One, which lies entirely in Pennsylvania (with an in-service date of November 2021). Though Phase One lies entirely in Pennsylvania, the New Jersey GDCs have executed precedent agreements (essentially, agreements to contract for firm transportation (“FT”) if the line goes forward) for Phase One.<sup>1</sup> The GDCs entered into the agreements totaling 405 MDth/d at the outset of the project, before it was split into two phases.

The Phase Two portion would have included the remaining route in Pennsylvania and New Jersey, with a targeted completion date of 2023.

The US Supreme Court ruled in June 2021 that a natural-gas pipeline that has received approval by a federal agency such as FERC can use eminent domain to access state-owned land (a matter which was disputed by the State of New Jersey). In spite of that, the developers of PennEast announced in September 2021 that further development efforts were unwarranted, and cancelled the project.

Sources: PennEast Pipeline website; Supreme Court of the United States. *PennEast Pipeline Company, LLC, Petitioner v. New Jersey, et al.* February 20, 2020.

## 2.2 Market structure review: How the GDCs provide gas to customers

In 2020, there were approximately 3.1 million natural gas consumers in New Jersey, served primarily by Public Service Electric and Gas (“PSE&G”) with 1.9 million customers, followed by NJNG, South Jersey Gas (“SJG”), and Elizabethtown Gas (“ETG”). The GDCs serve mostly residential and commercial customers, accounting for on average 91% and 7% of total customers, respectively (see Figure 7). Residential and commercial gas demand is driven mostly by heating needs in the winter. About 75% of the State’s households rely on natural gas as their primary home heating fuel.<sup>11</sup>

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<sup>11</sup> EIA. [State Profile and Energy Estimates: New Jersey](#). September 17, 2020.

Figure 7. Customer class breakdown by GDC (2020)

GDC	Total number of customers	% of total			
		Residential	Commercial	Industrial	Other *
Elizabethtown Gas Co.	301,613	92%	8%	0.03%	-
New Jersey Natural Gas Co.	558,166	89%	5% **		6%
Public Service Electric and Gas Co.	1,864,691	91%	8%	0.33%	0.001%
South Jersey Gas Co.	404,886	93%	7%	0.10%	-
<b>Average across all NJ GDCs</b>		91%	7%	1%	3%

\* For NJNG, “Other” includes firm transportation, interruptible, and BGSS incentive program customers; for PSE&G, “Other” includes street lighting customers.

\*\* NJNG reports customer numbers for “commercial, industrial and other” collectively.

Sources: SEC 10-K Form filings; Public Service Enterprise Group. [2021 PSEG Investor Fact Book](#). April 12, 2021.

The four GDCs are regulated by the NJ BPU, and are required to provide safe, adequate, and proper gas services at reasonable rates for the customers they serve.<sup>12</sup> As part of this service, GDCs submit BGSS filings on an annual basis. These reports fulfill minimum filing requirements, including a five-year forecast of design day demand – i.e., the demand expected by each GDC on the coldest day of the year.

To meet this forecasted design day demand, the state’s four GDCs generally rely on the following gas supply resources:

- **firm transportation (“FT”) contracts with gas pipelines:** GDCs contract for firm gas transportation capacity on interstate natural gas pipelines serving New Jersey. These contract arrangements are discussed in Section 2.2.1. Details of which pipelines serve which GDCs can be found in Appendix 1 (Section 6);
- **access to storage:** GDCs hold storage contracts to balance gas supply with demand throughout the year, as well as to meet shorter-term fluctuations in demand. These contracts are discussed in Section 2.2.4;
- **on-system peak-shaving capabilities:** GDCs own and operate liquefied natural gas (“LNG”) peaking facilities to provide back-up supplies during extreme weather conditions. These assets are discussed in Section 2.2.4; and
- **off-system peak shaving contracts:** GDCs contract with suppliers for bundled commodity and transportation to meet peak demand.

As will be discussed in the following subsections, the bulk of design day demand is met through pipeline capacity that GDCs secure through FT and storage contracts. Additional resources are deployed during peak periods on a short-term basis to meet the remaining demand – these include on-system peak-shaving facilities, as well as off-system short-term peaking contracts.

<sup>12</sup> NJ BPU. [About NJBPU](#).

## 2.2.1 GDC contract arrangements for commodity and capacity

GDCs note that they buy gas with the overarching goal of maintaining a reliable supply while obtaining the best value at a competitive price. For instance, ETG “secures the majority of its natural gas commodity requirements at the market prices in effect at the time the gas is needed,” which utilizes “spot-related or index-based pricing terms that are market sensitive.”<sup>13</sup>

To partially offset the volatility associated with these spot-related or index-based contracts for the commodity and save costs if possible, GDCs also implement hedging strategies. For example, PSE&G, in its most recent BGSS filing, noted that the goal of its “hedging activities is to achieve a stable price through a disciplined hedging strategy that will, in the long run, result in a competitive price for the customer.”<sup>14</sup>

As for contract arrangements for capacity, GDCs contract for FT on the five pipelines serving New Jersey. FT guarantees access to a maximum daily quantity (“MDQ”) of gas, and as such is generally not subject to reduction or interruption outside of abnormal operations. This guarantee is crucial, because GDCs rely on FT to reliably serve their customers. To guarantee access, GDCs “reserve” the MDQ by paying a fixed cost, known as a reservation rate. The reservation rate is quoted based on the quantity of capacity reserved per month and is paid regardless of whether GDCs ultimately use the capacity or not.

FT contracts enable GDCs to have first call on pipeline capacity and are scheduled and prioritized according to their receipt and delivery points.<sup>15</sup> Primary receipt and delivery points refer to the path of a pipeline; gas flowing on the FT primary path has the highest priority on the pipeline. In contrast, gas flowing on the primary path between secondary receipt or delivery points has a lower priority than primary FT service, but a higher priority than interruptible service (discussed later in Section 2.2.2).

## 2.2.2 FT on potential PennEast project

A precedent agreement is a contract to take FT service that a potential foundational shipper enters into with a pipeline developer before a project is constructed. Such agreements help provide the evidence that a pipeline is necessary, and pipeline developers refer to precedent agreements in their petitions to FERC for the certificate of need (“CN”) required to build or expand gas pipelines. The New Jersey GDCs had a total of 405 MDth/d of FT under precedent agreement with the PennEast Pipeline (see Figure 8).

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<sup>13</sup> ETG. *In the Matter of the Petition of Elizabethtown Gas Company to Review its Periodic Basic Gas Supply Service Rate: Case Summary, Petition, Testimony and Schedules*. June 1, 2020.

<sup>14</sup> PSE&G. *In the Matter of Public Service Electric and Gas Company’s 2020/2021 Annual BGSS Commodity Charge Filing for its Residential Gas Customers under its Periodic Pricing Mechanism and for Changes in its Balancing Charge*. June 1, 2020.

<sup>15</sup> Receipt points are the points at which gas is delivered into the pipeline (e.g., the interconnection between the producer’s wellhead facilities and the pipeline system). City gate delivery points are where the interstate pipeline interconnects with the GDC’s facilities. (Source: Energy Solutions Inc. [Energy Glossary](#).)

The precedent agreements were referred to by the PennEast project developer in its CN application, which was filed with FERC in 2015. As LEI noted previously, the PennEast project would not have reached New Jersey until 2023, when Phase 2 was to have been completed.

**Figure 8. Precedent agreements between New Jersey GDCs and PennEast**

GDC	FT on PennEast (Dth/d)
ETG	25,000
NJNG	180,000
PSE&G	125,000
SJG	75,000
Total	405,000

Sources:

ETG. *In the Matter of the Petition of Elizabethtown Gas Company to Review its Periodic Basic Gas Supply Service Rate: Case Summary, Petition, Testimony, and Schedules*. May 31, 2019. PDF p. 109;

NJNG. *PennEast Pipeline Company, LLC, Docket No. CP 15-558-000 Comments Regarding the October 25, 2016 memorandum from John Collins, Energy Industry Analyst, FERC Staff, to the FERC Office of the Secretary Reply to New Jersey Division of Rate Counsel Comments*. November 2, 2016;

SJG. *In the Matter of the Board's Order Regarding Natural Gas Supply Estimates and New Customers (Docket Nos 748-639, 774-363 and GE90070658)*. November 30, 2020. PDF p. 107;

PSE&G. *In the Matter of Public Service Electric and Gas Company's 2020/2021 Annual BGSS Commodity Charge Filing for its Residential Gas Customers under its Periodic Pricing Mechanism and for Changes in its Balancing Charge*. June 1, 2020. PDF p. 139.

Unlike FT tariffs which are public information and can be found in FERC databases, the pricing terms of natural gas precedent agreements are not usually public. Once the project is completed, the precedent agreement gives way to the tariff rates, which are publicly available.

### 2.2.3 New Jersey's interruptible customer profile

In addition to serving firm customers, the GDCs also supply interruptible customers. Customers under an interruptible service tariff receive gas service only if it is available, and as such are subject to curtailment or interruption due to operating conditions or pipeline capacity constraints.

Although the number of interruptible customers served by each GDC is not reported as part of their BGSS filings, assessing the share of total demand attributable to interruptible customers gives a sense of the size of this group. Figure 9 lists the total demand or sendout for each GDC, which is averaged across the five peak days for each of the past three winters (2017-2020). The table also lists the portion of this demand that was attributable to interruptible customers. On average, interruptible customers accounted for around 3% of demand served by GDCs, a small share of the customer base.

**Figure 9. Interruptible customers by GDC (as a percentage of total sendout)**

GDC	Average demand (Dth), 2017-2020 peak days		
	Interruptible	Total	%
Elizabethtown Gas Co.	26	380,828	0.01%
New Jersey Natural Gas Co.	1,648	673,560	0.27%
Public Service Electric and Gas Co.	250,929	2,479,929	10.40%
South Jersey Gas Co.	8,621	437,575	2.12%
<b>Average across all NJ GDCs</b>			<b>3.20%</b>

Note: Values shown (in Dth) are the average demand values for the five highest demand days for each of the 2017-2020 winters (i.e., 15 demand days total).

Sources: GDC BGSS filings for 2020-2021 – Schedule TK-10 (ETG), Exhibit JSS-3 (NJNG), Item 15 (PSE&G), TWR-7 (SJG).

Under interruptible service, customers may receive curtailment requests to discontinue their natural gas use temporarily; these requests are usually made by GDCs via telephone, email, or fax, with not less than three hours’ notice. Failure to comply with such requests generally results in a penalty, whereby customers are charged for unauthorized usage. This charge is defined differently for each GDC:

- **ETG:** bills customers at the higher of \$2.50 per therm (\$25.00/MMBtu) or a rate equal to ten times the highest price of the daily ranges for delivery in Transco Zone 6 or Tetco M-3 (a natural gas pricing hub);<sup>16</sup>
- **NJNG:** bills customers at the rate of ten times the highest price of the daily ranges for delivery in Tetco M-3;<sup>17</sup>
- **PSE&G:** charges customers \$1.89 per therm (\$18.90/MMBtu) for “an amount not to exceed one hour’s maximum requirement per day of interruption.” Gas used beyond this amount is billed at ten times the highest price of the daily ranges for delivery in Transco Zone 6 or TetcoM-3;<sup>18</sup> and
- **SJG:** bills customers at the rate of ten times the highest price of the daily ranges for that month for delivery to Transco Zone 6 non-New York.<sup>19</sup>

## 2.2.4 Gas storage availability and contracting

Underground storage of natural gas is crucial for balancing gas supply and demand throughout the year and meeting shorter-term fluctuations in demand. Because these fluctuations are inherently seasonal (i.e., demand rises in the winter as natural gas is used to heat homes in the

<sup>16</sup> ETG. [Tariff for Gas Service: B.P.U. No. 17](#), November 14, 2019.

<sup>17</sup> NJNG. [NJNG Tariff – BPU No. 10 – Gas](#), November 13, 2019.

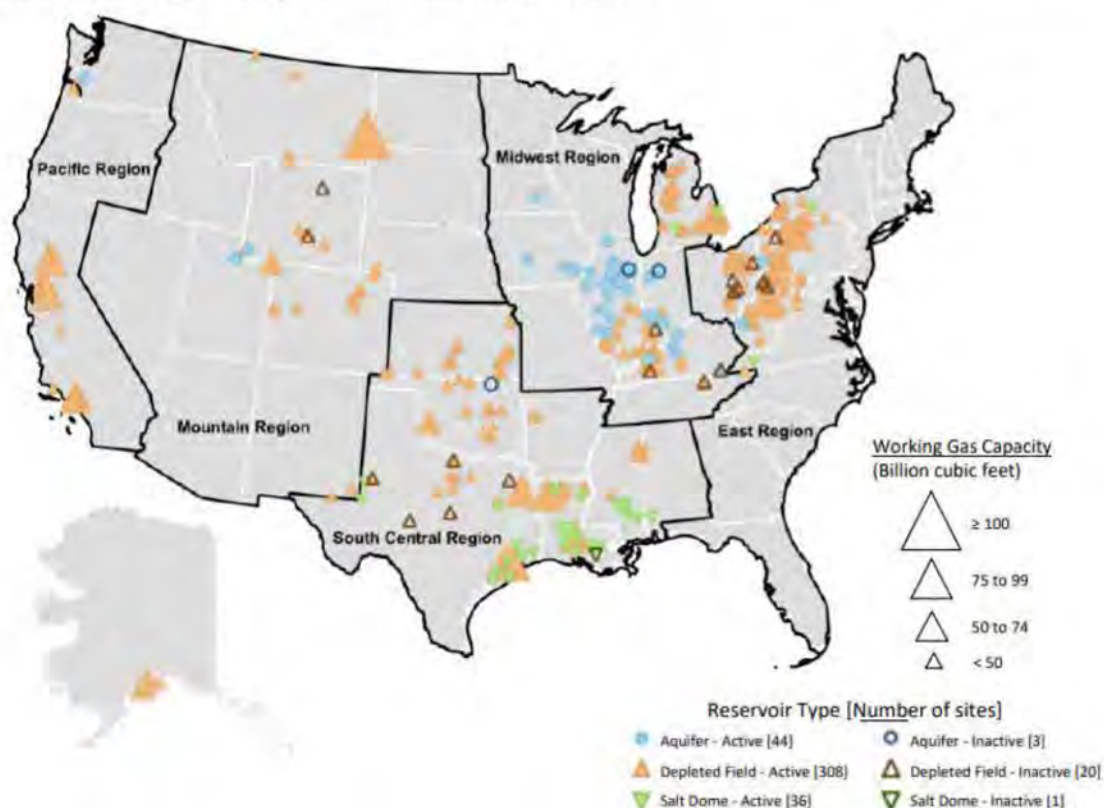
<sup>18</sup> PSE&G. [Tariff for Gas Service – B.P.U.N.J. No. 16 GAS](#), October 30, 2018.

<sup>19</sup> SJG. [Tariff for Gas Service: B.P.U.N.J. No. 13 – GAS](#), March 13, 2020.

state), GDCs buy and store gas supply in the off-peak season for later use when demand rises. Storage also provides a hedge against unforeseen disruptions in production.

Generally, depleted oil or gas wells, depleted aquifers, and salt caverns all serve as potential gas storage sites; depleted natural gas or oil fields located close to consumption centers are the most used sites in the US including in the Northeast. However, no underground gas storage fields exist in New Jersey or New England, as the geology in those locations is not suitable (see Figure 10).

Figure 10. Natural gas storage fields across the US (2019)



Source: EIA. [Natural Gas Annual: Locations of existing natural gas underground storage fields in the United States, 2019.](#)

GDCs in the State contract with pipelines to utilize storage facilities on the pipeline system. Figure 11 lists the storage contract volumes for each GDC for the Q4 2020 reporting period, according to each pipeline's Index of Customers. According to the Index, GDCs in the state held nearly 80,000 MDth of storage capacity, mostly with Transco (57%) and Tetco (22%).

Figure 11. Storage contract volumes by GDC and pipeline, Q4 2020

GDC	Pipeline	Contract Maximum Storage (MDth)
Elizabethtown Gas Co.	Columbia Gas Transmission, LLC	230
	Texas Eastern Transmission, LP	380
	Transcontinental Gas Pipe Line Company, LLC	6,676
	<b>Total</b>	<b>7,286</b>
New Jersey Natural Gas Co.	Columbia Gas Transmission, LLC	370
	Tennessee Gas Pipeline Company, L.L.C.	8,435
	Texas Eastern Transmission, LP	7,542
	Transcontinental Gas Pipe Line Company, LLC	922
<b>Total</b>	<b>17,269</b>	
Public Service Electric and Gas Co.	Tennessee Gas Pipeline Company, L.L.C.	8,583
	Texas Eastern Transmission, LP	5,191
	Transcontinental Gas Pipe Line Company, LLC	28,071
	<b>Total</b>	<b>41,844</b>
South Jersey Gas Co.	Columbia Gas Transmission, LLC	3,473
	Transcontinental Gas Pipe Line Company, LLC	9,114
	<b>Total</b>	<b>12,587</b>
<b>Total across all NJ GDCs</b>		<b>78,986</b>

Notes:

- 1) Rate schedules included in the analysis are ESS, FS, FSS, GSS, LSS, S-2, SS, SS-1, SS-2, SST, WSS-OA.
- 2) The ETG contracts include those with shipper name Elizabethtown Gas Co. NJNG contracts include those with the shipper names New Jersey Natural Gas Co. and NJR Energy Services. PSE&G contracts include those with the shipper names PSE&G Energy Resources, PSE&G Power LLC, and Public Service Electric Gas. SJG contracts include those with the shipper names South Jersey Gas Co. and South Jersey Rsrc Grp.

Sources: S&P Global Market Intelligence. *Index of Customers*. Q4 2020.

In addition to these storage contracts, GDCs also use LNG to balance supply. LNG peaking facilities store gas in above-ground vessels for days when gas demand is extremely high. Figure 12 lists these peaking resources by GDC, separating LNG contracts secured with pipelines from the LNG facilities that are owned and operated by the GDC itself.

According to the Index of Customers for the Q4 2020 reporting period, three of the four GDCs held a total volume of 1,719 MDth in LNG contracts, all of which were attributable to Transco's Carlstadt LNG facility (see Figure 12 under the 'contracted resources' heading).<sup>20</sup> All four GDCs also operate their own peaking facilities to provide backup supply on peak demand days, with a reported total maximum daily sendout capability of 533 MDth/d, according to each GDCs most recent BGSS filing (see the table under the 'on-system resources' heading). These facilities consist mostly of LNG plants (63%), as well as liquified propane air ("LPA") assets (37%). The total 533 MDth/d is included as a supply resource in LEI's Shortfall Risk Assessment in Section 4.

<sup>20</sup> Transco's LNG service consists of the liquefaction of natural gas, the storage of such LNG, and the gasification and delivery of such gas.



Figure 12. Peaking resources by GDC (contracted and on-system)

Contracted resources		
GDC	Contract Maximum Storage (MDth)	
Elizabethtown Gas Co.	155	
Public Service Electric and Gas Co.	1,349	
South Jersey Gas Co.	215	
<b>Total</b>	<b>1,719</b>	

On-system resources		
GDC	Facility	Capability (MDth/d)
Elizabethtown Gas Co.	Erie Street (LNG)	25
New Jersey Natural Gas Co.	Howell (LNG)	150
	Stafford (LNG)	20
Public Service Electric and Gas Co.	Burlington (LNG)	67
	LPA	196
South Jersey Gas Co.	McKee City (LNG)	75
<b>Total</b>		<b>533</b>

Sources: S&P Global Market Intelligence. *Index of Customers*. Q4 2020; GDC BGSS filings for 2020-2021.

Note: Maximum storage capacity is quoted in total volumes, while on-system resources are quoted in daily sendout volumes.

### 2.2.5 Retail energy choice

New Jersey began opening its natural gas market to retail choice in the 1990s, beginning with commercial and industrial customers in 1994.<sup>21</sup> This market structure was then tested among residential customers through pilot programs implemented by GDCs, and was officially implemented in 1999 through the passing of the Electric Discount and Energy Competition Act (“EDECA”).

Under EDECA, residential customers can buy gas from a provider other than their GDC (i.e., a licensed third-party supplier (“TPS”)).<sup>22</sup> TPSs were established as a result of retail choice legislation passed under New Jersey’s EDECA, which enables customers to shop for energy supplies from a TPS. TPSs generally deliver gas to the GDCs’ city gates, which GDCs are then responsible for transporting to customers.

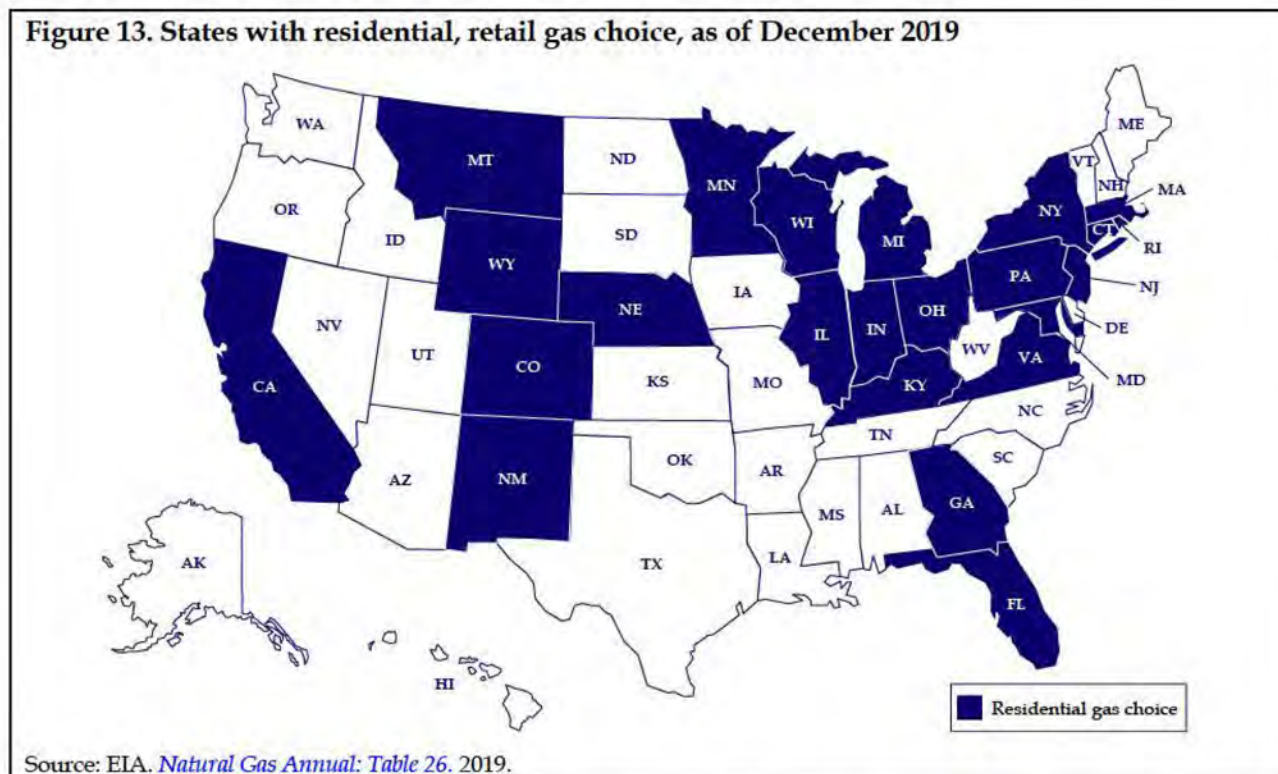
<sup>21</sup> The New Jersey Division of the Ratepayer Advocate. [Position Paper on the Status of Restructuring in the Natural Gas Market](#). February 1998.

<sup>22</sup> NJ Power Switch. [Know Your Rights](#).

GDCs continue to provide gas supply for customers that choose not to shop (i.e., those under Basic Gas Supply Service). There are currently over 75 licensed TPSs serving New Jersey customers, offering contracts with either fixed or floating terms.<sup>23</sup>

Similar customer choice programs exist across the country, with the competition open to residential gas customers in 23 states (including New Jersey) and the District of Columbia – see Figure 13.

Figure 13. States with residential, retail gas choice, as of December 2019



Source: EIA. [Natural Gas Annual: Table 26](#). 2019.

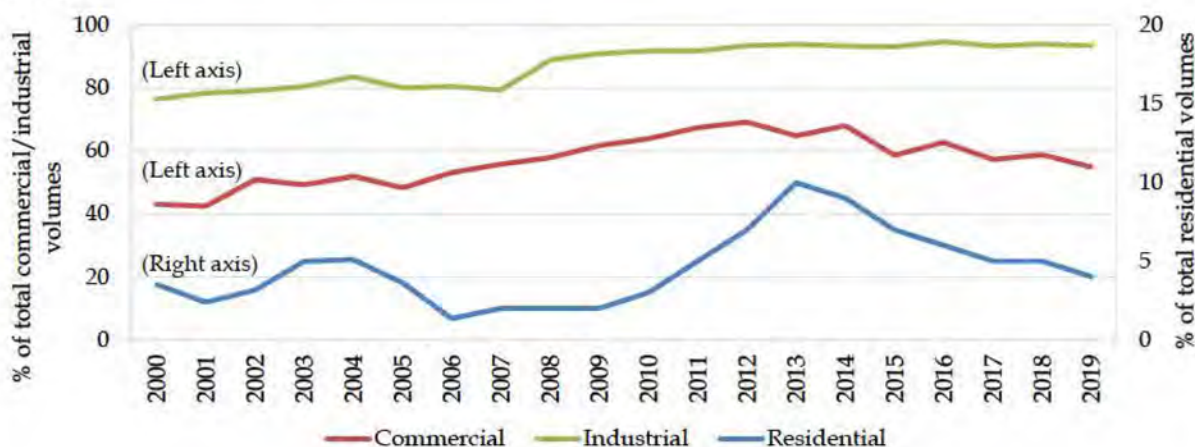
Since the implementation of retail choice in New Jersey, uptake and interest has differed across the various customer types. Over the 2000-2019 period, residential participation averaged only 5% of total residential deliveries, while commercial and industrial participation was significantly higher (accounting for 57% and 88% of commercial and industrial deliveries, respectively) (see Figure 14). By 2019, residential participation dipped to 4%, commercial participation fell to 55%, while industrial participation rose to 94%. Across all customer classes, retail choice deliveries in 2019 accounted for around 20% of total deliveries made by GDCs in the state.

Participation has fluctuated among residential customers in particular, with uptake peaking in 2013 at 10% of total residential deliveries before declining (see again Figure 14). Although it is not exactly clear what drove this trend, it seems that participation fluctuated in line with natural gas

<sup>23</sup> Under a fixed contract, customers pay a set, agreed-upon price for energy supplies throughout the term of the contract. Floating (or variable) contracts allow a customer's price to fluctuate on a monthly basis, tracking the wholesale cost of natural gas. (Source: NJ Power Switch. Fixed v. Variable Rates <<https://nj.gov/njpowerswitch/shop/rates/>>)

price trends. For example, Henry Hub spot prices peaked at \$8.86/MMBtu in 2008, and have declined ever since, reaching \$2.56/MMBtu in 2019.

**Figure 14. Share of customers in New Jersey participating in retail choice, as a percentage of total volumes**



c

Source: EIA. [Natural Gas Delivered for the Account of Others](#). Note: EIA defines natural gas delivered for the account of others as gas that is not owned by the company that delivers it to the consumer. This includes gas covered by long-term contracts and gas involved in short-term or spot market sales.

### 2.2.5.1 Not transparent how much third-party supply is matched to FT contracts

Over the 2015-2019 period, daily sendout by TPS in New Jersey averaged 439 MDth/d, and most of the gas which TPSs provided was for commercial and industrial (“C&I”) customers (see Figure 15). These customers are likely to be interruptible customers, in which case the TPS would probably not wish to match its gas sales commitment with FT. But if some C&I retail choice customers were on firm service, then in a situation of peak demand and limited transportation capacity, the TPSs might not be able to meet this firm demand. Based on available information, LEI cannot determine if TPSs have enough FT capacity to meet their firm demand.

**Figure 15. Average historical TPS deliveries in New Jersey by customer type**

Year	MDth/d			Total
	Residential	Commercial	Industrial	
2015	43	262	141	446
2016	34	263	158	455
2017	32	234	139	405
2018	31	270	165	466
2019	23	233	167	423

Note: EIA data reports annual deliveries in MMcf. Although peak day deliveries cannot be calculated from this data, LEI reports average daily deliveries across the year (in MDth/d) in the table above as a proxy.

Source: EIA. [Natural Gas Delivered for the Account of Others](#).

Rather than commit to FT on a long-term basis, short-term capacity release agreements with GDCs are commonplace among TPSs. For capacity releases awarded to TPSs in 2020, the contract length averaged only 68 days (see Figure 16). Not only are capacity release contracts of short duration, the GDC can recall any capacity which it needs to serve its own load.

**Figure 16. Average length of TPS capacity release agreements with GDCs, 2020 award dates**

TPS (replacement shipper)	Average contract length (days)	Average award quantity (MDth/d)
Colonial Energy Inc	4	4
ConocoPhillips Company	213	4
Direct Energy Business Marketing LLC	2	21
ENGIE Power & Gas LLC	31	0.4
Infinite Energy, Inc.	1	10
Just Energy New York Corporation	31	0.1
Mansfield Oil Company	214	9
Marathon Energy Corp	31	0.2
Talen Energy Marketing, LLC	3	15
UGI Energy Services, Inc.	151	3
<b>Average</b>	<b>68</b>	<b>7</b>

Source: S&P Global Market Intelligence. *Capacity Release by Releasing Shipper*. 2020.

### 2.2.5.2 GDCs are able to cover some, but not all, of the TPS load if it were to shift to BGSS

Each GDC accounts for potential customer switching from TPSs to BGSS slightly differently in their outlooks for design day firm gas demand. The underlying switching assumptions used by each GDC are as follows:

- **PSE&G** forecasts customer migration “based on previous trends and incorporates known differences. Monthly switching data (by rate class) to and from TPSs is trended and analyzed. ... Any known future customer switches are reflected in forecasted data”;<sup>24</sup>
- **NJNG** “does not assume switching activity in its forecasts. The level of transportation customers at the time of the forecast is included for the current and future period”;<sup>25</sup> and
- **SJG** “tracks customer switches to and from TPSs on a monthly basis and incorporates the most current information in its forecast by holding the most recent TPS-served volumes constant for future periods”;<sup>26</sup> and

<sup>24</sup> PSE&G. *In the Matter of the Exploration of Gas Capacity and Related Issues*, Docket No. GO19070846. October 22, 2019. p. 5.

<sup>25</sup> NJNG. *Comments from New Jersey Natural Gas Company Pertaining to Docket No. GO19070846*. October 16, 2019. p. 4.

<sup>26</sup> SJI. *In the Matter of the Exploration of Gas Capacity and Related Issues (BPU Docket: GO19070846)*. October 22, 2019. p. 5.

- ETG “also uses the most current TPS switched information” and “incorporates a general utility growth trend identified in the number of customers switching to TPSs into its forecast.”<sup>27</sup>

As none of the GDCs assume that the full TPS load switches to BGSS, it is evident that the GDCs’ design day outlooks include firm capacity to cover only a portion of the TPS load, but not necessarily the full TPS load. As a result, if a substantial and unexpected volume of TPS load were to switch back to BGSS, GDCs may not have sufficient FT to serve all customers on a design day. However, it is probable that not all the TPS load is firm; some commercial and industrial demand could be interruptible, as noted above.

### **2.3 Demand review and LEI scenarios for firm demand**

Projections for design day firm gas demand in the State provide the foundation for GDC capacity needs. For the coming decade, design day firm demand is likely to be impacted by energy efficiency requirements and targets. In this section, LEI examines historical trends and develops two sets of design day demand scenarios to 2030.

#### **2.3.1 New Jersey gas demand has shifted to the electric power sector**

Natural gas demand in New Jersey has been growing over the past few years; most natural gas usage occurs during the winter, driven by residential usage for heating. About 75% of New Jersey households rely on natural gas for home heating purposes.<sup>28</sup> Over the past ten years through 2019, New Jersey’s natural gas consumption grew at a compounded annual growth rate (“CAGR”) of 1.8%. This growth was driven by increased deliveries to electric power consumers (4.6% CAGR)<sup>29</sup> and industrial customers (3.1% CAGR) (see Figure 17).

Consumption growth among residential customers was slower than the overall growth rate at 1.0% CAGR, and consumption from commercial customers actually declined. The long-term decline in commercial natural gas use per customer is widespread across the United States. Reasons for this include more energy efficient equipment, improvements to building shells including insulation, population migrations to warmer climates, conservation efforts, and the effectiveness of utility-sponsored efficiency programs.<sup>30</sup>

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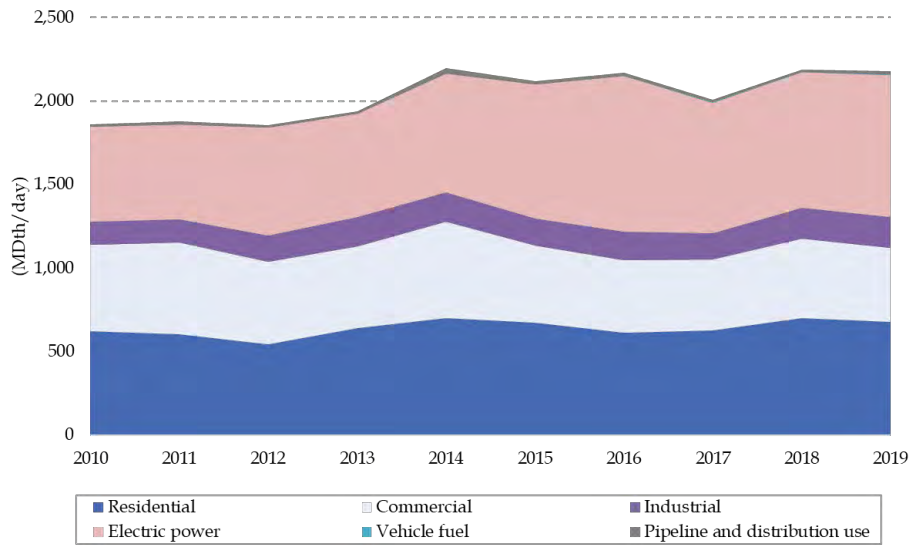
<sup>27</sup> Ibid. p. 5.

<sup>28</sup> US Energy Information Administration. *New Jersey: State Energy Profile*. Updated: September 17, 2020.

<sup>29</sup> US Energy Information Administration. *Natural Gas Consumption by End Use*. Updated: January 29, 2021.

<sup>30</sup> American Gas Association. *Uncovering the US Natural Gas Commercial Sector*. January 2017.

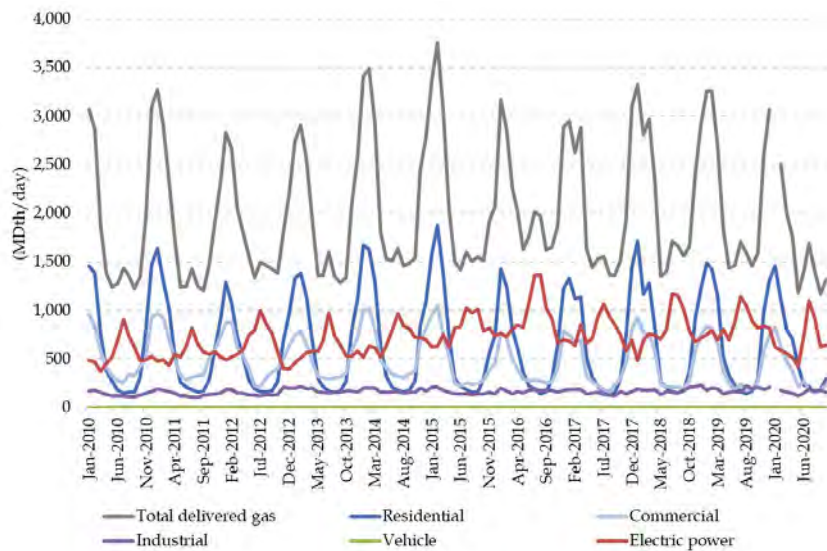
Figure 17. Annual natural gas consumption in New Jersey (2010-2019)



Source: Energy Information Administration. *Monthly Energy Review*. December 2020. <https://www.eia.gov/outlooks/steo/>

Residential consumption for heating during the coldest months of the year, usually January or February, drives a winter peak in total demand (see Figure 18). These winter peaks are important because the gas delivery system (interstate pipelines, distribution pipelines, and gas storage) must be designed to meet such peaks, rather than average annual consumption. GDCs plan for demand from their BGSS customers, for some demand from switching customers, and in some cases, they include a reserve margin. They base their outlooks on a design day criterion (i.e., the highest demand that the GDC will be obligated to serve on the coldest winter day).

Figure 18. Historical monthly natural gas consumption in New Jersey (2010-2020)



Source: Energy Information Administration. *Monthly Energy Review*. December 2020. <https://www.eia.gov/outlooks/steo/>

### **2.3.2 Design day firm demand is the focus of reliability planning**

Design day firm demand is the gas sendout that a GDC expects to have to provide during an extremely cold day, to its firm (non-interruptible) customers; it is the demand that the system is designed to meet. Traditionally, projected peak winter demand from firm customers determines the standard for which gas distribution companies' infrastructure (pipelines, storage, distribution system, and peaking facilities) must be designed. The New Jersey GDCs report historical demand on peak days in their annual BGSS filings; they project system needs based on assumptions that generate estimates for future design day demand. Design day demand projections are focused on BGSS load, but as noted above, may include a portion of TPS demand, depending on the utility.

This section focuses on firm demand – the demand that the GDCs are required to meet to serve all residential, most commercial, and some industrial customers. This is in contrast to total demand for natural gas on historical peak days, which includes demand from interruptible customers such as large electric generation plants, and some commercial and industrial customers. Firm customers are first in line for gas delivery, and unlike interruptible customers, must be served no matter the weather.

Though gas consumption in New Jersey has been growing over the past decade, most of this growth has been from the electric power sector. To the extent the power sector is not contracting for FT on interstate pipelines or on laterals belonging to GDCs, nor contracting for substantial amounts of gas in storage, the power sector is last in line for gas delivery with other interruptible customers.

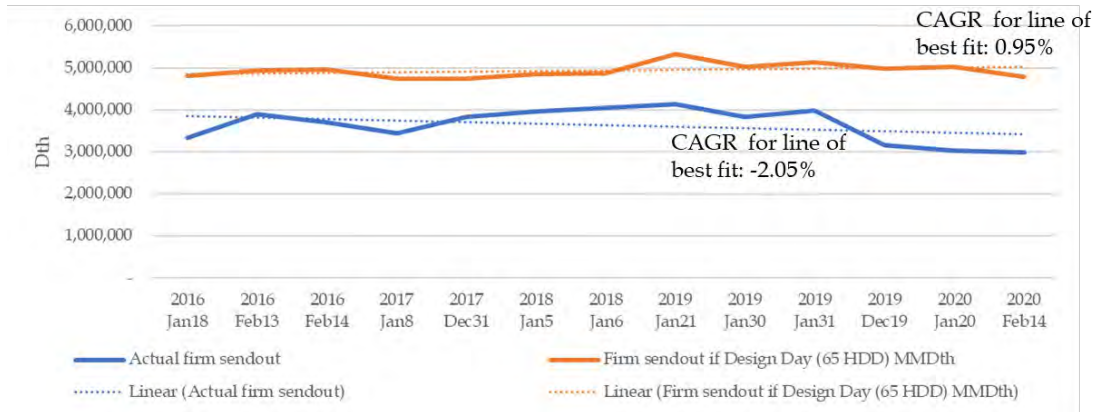
### **2.3.3 Weather-normalized firm peak demand increased about 0.95% per year**

In the past five years, the GDCs reported that firm sendout on peak demand days declined by 2.05% CAGR (the slope of the line of best fit of the blue line in Figure 19), and in 2020 firm sendout was about 3,000 MDth on the coldest days in January 2020.

However, the CAGR measurement overstates the decline in peak day demand because actual January 2020 demand was atypically low. It also does not normalize for the impact of weather. For example, the relatively low peak day demand on January 20, 2020, may have been because the day was warmer than the peak day of February 13, 2016.

LEI normalized for the impact of weather by dividing historical peak day sendout by the number of heating degree days (“HDD”) on each reported day. On a weather-normalized basis, peak day demand per HDD grew about 0.95% annually over the five-year period (see Figure 20). If, instead of actual historical weather, the coldest days all reflected much colder design day weather (discussed in more detail in the next section), then design day sendout would also have increased 0.95% per year (see the slope of the line of best fit for the orange line in Figure 19).

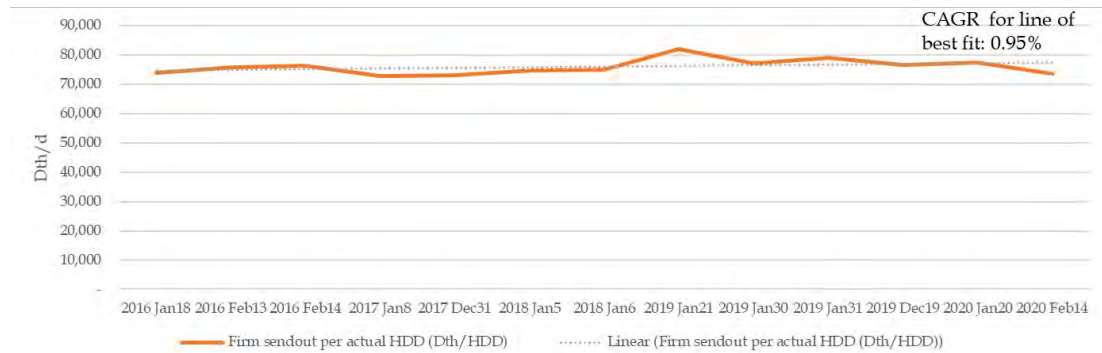
**Figure 19. Firm sendout for all four GDCs on peak demand days, and hypothetical design days**



Sources: 2016-2018 – 2018 BGSS filings for NJNG, SJG, PSE&G, ETG; 2019-2020 – 2020 BGSS filings for all four GDCs

Note: Data is from utility-reported sendout on five highest demand days for past three years, for only the days in which all four utilities reported information for the same day. This accounted for less than five days per year, because not all utilities experienced peak demand on the same days.

**Figure 20. Firm sendout per HDD for all four GDCs**



Year/month/day	Average of reported HDD	Actual firm sendout	Firm sendout per actual HDD (Dth/HDD)	Firm sendout if Design Day (65 HDD) MMDth
2016 Jan18	45.14	3,333,207.00	73,849.72	4,800,231.64
2016 Feb13	51.25	3,888,883.00	75,880.64	4,932,241.85
2016 Feb14	48.41	3,693,505.00	76,304.20	4,959,773.27
2017 Jan8	47.30	3,443,771.00	72,807.00	4,732,454.86
2017 Dec31	52.52	3,836,949.00	73,063.87	4,749,151.39
2018 Jan5	53.11	3,969,746.00	74,752.77	4,858,930.23
2018 Jan6	54.10	4,054,261.00	74,943.59	4,871,333.52
2019 Jan21	50.59	4,143,299.00	81,907.66	5,323,997.92
2019 Jan30	49.62	3,828,672.00	77,159.85	5,015,390.57
2019 Jan31	50.42	3,984,517.00	79,026.52	5,136,723.62
2019 Dec19	41.32	3,167,278.00	76,661.70	4,983,010.29
2020 Jan20	39.25	3,035,699.00	77,342.65	5,027,272.23
2020 Feb14	40.62	2,988,599.00	73,583.63	4,782,935.74

Sources: 2016-2018 – 2018 BGSS filings for NJNG, SJG, PSE&G, ETG; 2019-2020 – 2020 BGSS filings for all four GDCs

Notes: PSE&G refers to Newark average temperature, not HDD, so LEI used HDD from the other utilities for corresponding PSE&G peak days where available. ETG includes 2.04% lost and unaccounted-for gas (“LAUF”) in total throughput.



### 2.3.4 GDCs project design day firm demand to increase 1.02% per year to 2025

In 2020, GDC projections overall were for an increase in design day firm demand of 1.02% per year from 2020/21 to 2024/25 (see Figure 21). This is higher than the historical increase in demand per HDD of 0.95% per year discussed above. GDCs project their design day firm sendout to increase from 5,092 MDth/d in 2020/21 to 5,303 MDth/d in 2024/25 (an increase of 211 MDth/d over the period). The GDCs include retail choice customers in their GDC design day demand outlooks.

**Figure 21. Design day planning outlook for firm sendout, all four GDCs (MDth/d)**

	2020/21	2021/22	2022/23	2023/24	2024/25	CAGR 2020/21 to 2024/25
ETG	598	605	611	618	625	1.10%
NJNG	934	945	955	964	974	1.05%
PSE&G	2,981	2,997	3,037	3,060	3,088	0.89%
SJG	579	588	597	607	617	1.59%
<b>Total</b>	<b>5,092</b>	<b>5,135</b>	<b>5,200</b>	<b>5,249</b>	<b>5,303</b>	<b>1.02%</b>

Sources: 2020 BGSS filings for ETG, NJNG (Total sendout, from “Workpaper 7” Docket #GR20060378), PSE&G (Item 16 - Peak day sendout forecast), SJG (5 Year Supplies and Requirements Report) and SJG response to DR 1-005 “SJG Gas Cap & Related Issues Discovery Responses (02 21)s.” Excludes LOLP volumes for those GDCs (NJNG and PSE&G), which include them in their outlooks.

Each of the GDCs defines design day in a similar, but not uniform, way:

- **NJNG:** explains that “Design day conditions (“DDC”) are extreme weather conditions for which the design day sendout forecast is calculated. The DDC for NJNG’s design day sendout forecast is a 1-in-90-year wind-adjusted temperature of -6.3 degrees Fahrenheit that equates to approximately 0 degrees Fahrenheit with a 16 mile-per-hour wind.”<sup>31</sup> LEI notes that -6.3 degrees Fahrenheit is equal to 71.3 HDD.
- **PSE&G:** reports that it calculates peak day sendout using regression analysis based on HDD, day of the week, and non-weather induced seasonal patterns, but does not specify the HDD standard it uses (though it refers to Newark average temperature in its BGSS filings);<sup>32</sup>
- **SJG:** uses 63 HDD for its design day assumption, based on the temperature on January 19, 1994;<sup>33</sup> and

<sup>31</sup> NJNG response to DR 1.4 “02-24-2021 NJNG GR20010033 BGSS Gas Capacity Discovery Responses to BPU only.”

<sup>32</sup> Overland Consulting. [Audit of Relationships and Transactions Between Public Service Electric and Gas Company and its Affiliates and a Comprehensive Management Audit of Public Service Electric and Gas Company](#). January 2012.

<sup>33</sup> South Jersey Gas. *BPU Docket No. GR10010035. Direct Testimony of Michael J. McFadden A.E. Middents and John N. Peters on behalf of the New Jersey Department of the Public Advocate, Division of Rate Counsel*. May 28, 2010.

- ETG: uses 65 HDD.<sup>34</sup>

The coldest day in 30 years, also known as “once-in-30 years,” is a commonly used design day standard. In a recent survey of 79 US gas utilities, 29 used a once-in-30 years probability of occurrence, ten used a once-in-20 years probability, and 24 used other criteria including 40, 50, or, like NJNG, up to a maximum one-in-90 years probability.<sup>35</sup>

In comments in response to requests for information related to a stakeholder meeting held on April 29, 2021, the GDCs noted that they did not favor adoption of a uniform approach to projecting design day requirements.<sup>36</sup> For example, one response noted that *“There are differences between each GDC – including between ETG and SJG -- in terms of their respective portfolio of assets and capacities owned and under contract to serve design day requirements, geographic locations and mix of customers. A one-size-fits all approach that disregards these differences would translate into disproportionate and compromised reliability across the GDCs.”*<sup>37</sup> In LEI’s view, the issue of whether the utilities use uniform design day criteria is outside the scope of the current analysis. The BPU may wish to examine the pros and cons of a standardized methodology in a future docket. For the purposes of the current analysis, it is simply important to be aware of the assumptions and methods used by the GDCs.

Compared to recent historical experience in New Jersey, design day demand based on 65 to 71 HDDs reflects extreme weather. During the memorable Polar Vortex of 2014, the coldest day in New Jersey was January 7, 2014, with 58 HDD.<sup>38</sup>

In this section, LEI examines the drivers of the GDCs’ outlooks and concludes that, as a whole they tend to overstate demand growth somewhat for the reasons described below.

#### 2.3.4.1 Drivers of GDC design day demand outlooks

Each GDC projects growth in design day firm demand (see Figure 22). LEI examined the drivers of each GDC’s design day outlook, to verify the reasonableness of their assumptions and methodology.

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<sup>34</sup> South Jersey Industries, Inc. and South Jersey Gas Company. [South Jersey Industries, Inc. and South Jersey Gas Company Form 10-K for Fiscal Year Ended December 31, 2019](#). EDGAR, Securities and Exchange Commission, 2020.

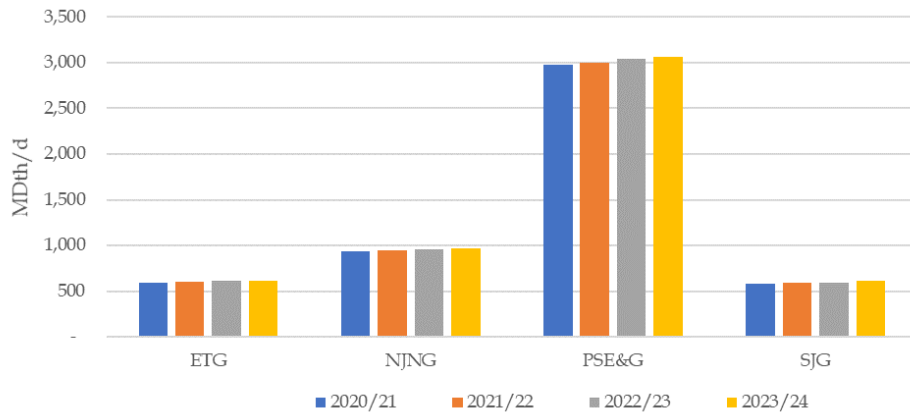
<sup>35</sup> American Gas Association. [EA 2016-03. LDC supply portfolio management during the 2014-15 winter heating season](#). June 15, 2016. Note that 79 utilities responded in whole or in part, so any given question might have less than 79 responses.

<sup>36</sup> ETG, SJG. “Comments of South Jersey Gas Company and Elizabethtown Gas Company.” BPU Docket No. GO19070846. May 13, 2021; NJNG, “Re: Comments from New Jersey Natural Gas Company Pertaining to Docket No. GO20010033.” May 13, 2021; PSE&G, “Re: 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.” May 13, 2021.

<sup>37</sup> ETG, SJG. “Comments of South Jersey Gas Company and Elizabethtown Gas Company.” BPU Docket No. GO19070846, May 13, 2021. P. 4.

<sup>38</sup> NOAA database. [CONUS. Heating Degree Days](#). February 17, 2021.

Figure 22. Design day planning outlook for firm sendout, by GDC



Sources: 2020 BGSS filings for ETG, NJNG (Total sendout, from “Workpaper 7” Docket #GR20060378), PSE&G (Item 16 - Peak day sendout forecast), SJG (5 Year Supplies and Requirements Report). Excludes LOLP volumes for those GDCs (NJNG and PSE&G), which include them in their outlooks.

#### 2.3.4.1.1 Econometric methodology is frequently used in utility demand forecasting

Utilities typically use econometric models as a foundational methodology to derive their demand forecasts. An econometric model estimates the historical relationship between drivers, aka independent variables (for example, economic growth, weather, household growth), and a dependent variable (for example, firm gas demand).

All the GDC models use weather (HDD) as a driver. In addition, a variety of other drivers, as discussed below (customer growth, economic growth, efficiency, etc.) are used by the GDCs to estimate (using an econometric model) the historical relationship between the drivers and firm gas demand. The GDCs project the value of the drivers going forward and use the econometric model results to calculate the impact on firm gas demand. For example, PSE&G reports that it calculates peak day sendout using regression analysis (a form of econometric analysis) based on HDD, day of the week, and non-weather seasonal patterns.<sup>39</sup>

In addition to the demand derived from the econometric model, utilities sometimes include adders to cover reserves needed for loss of load risk, as discussed in more detail below.

#### 2.3.4.1.2 Customer growth assumptions vary

Some GDCs incorporate explicit assumptions about customer growth into their design day demand outlooks, others do not:

- **ETG:** ETG does not explicitly track historical customer growth rates as a driver of future demand. Instead ETG’s regression model incorporates a time trend variable “t” which

<sup>39</sup> Overland Consulting, [Audit of Relationships and Transactions Between Public Service Electric and Gas Company and its Affiliates and a Comprehensive Management Audit of Public Service Electric and Gas Company](#), January 2012.

captures the impact of any and all trends over time.<sup>40</sup> Time trend variables are widely-used in econometrics and capture the net impact of all trends that change over time – for example, if increases in efficiency have reduced demand over time, but a growing customer base has increased demand, “t” will capture the net impact but cannot distinguish each effect individually;

- **NJNG:** NJNG’s firm demand forecast is based on the historical trends of customer growth in eight different statistical models.<sup>41</sup> The modeling system includes estimated customer growth, though NJNG did not specify the rate of growth it used in the 2020 outlook;<sup>42</sup>
- **PSE&G:** The forecast of residential gas sales is based on two components: a projection of the number of customers and gas use per customer. For number of customers, PSE&G assumes residential non-heating customers convert to gas heating customers at a rate of 1.2% per year.<sup>43</sup> For usage per customer, PSE&G relies on an econometric model which includes income, price of gas, HDD, and other variables; and
- **SJG:** Customer growth is driven by residential and commercial conversions from oil, and for residential customers is assumed by SJG to be 1.7% on average annually from 2020-2024.<sup>44</sup>

The GDCs incorporate a range of approaches to project customers switching from a TPS back to the utility (as discussed previously in Section 2.2.5.2):<sup>45</sup>

- **ETG:** ETG incorporates what it refers to as “a general utility growth” trend to project the number of customers switching back from TPSs in its forecast;
- **NJNG:** NJNG does not assume any change to switching activity in its forecasts; the level of transportation customers at the time of the forecast is held constant through the forecast period;
- **PSE&G:** PSE&G analyzes monthly switching data (by rate class) to and from TPSs to develop a forecast. PSE&G notes that residential and commercial customer switching is

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<sup>40</sup> ETG response to DR 1.1: Elizabethtown Gas. BPU Docket No. GR20010033. 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. Discovery Request. March 12, 2021.

<sup>41</sup> Response to DR 1.4: New Jersey Natural Gas. BPU Docket No. GO20010033. 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. Discovery Response. February 24, 2021.

<sup>42</sup> Ibid.

<sup>43</sup> Public Service Electric & Gas Company. Natural Gas Sales Forecast -2020. May 2020.

<sup>44</sup> SJG response to DR 1.10 “SJG Gas Cap & Related Issues Discovery Responses (02 21)s.” and South Jersey Gas. BPU Docket No. GR18060609. In the Matter of the Petition of South Jersey Gas Company to Revise the Level of its Basic Gas Supply Service (“BGSS”) and Conservation Incentive Program (“CIP”) Charges for the Year ending September 30, 2019. June 1, 2018.

<sup>45</sup> BPU Docket No. GO19070846), response to question 1c) “What assumptions does each GDC make and reflect in its forecasts about the switching of customers to and from TPSs?”

likely to follow historical trends, whereas larger commercial and industrial switching is more volatile and harder to predict; and

- **SJG:** SJG tracks customers switching on a monthly basis and holds the most recent TPS-served volumes constant for future periods (a similar approach to ETG's).

As shown previously in Figure 14, about 5% of residential customers by volume of gas were supplied by TPSs in 2019, a trend which had been declining over time. This implies that the trend of customers returning to BGSS has been positive over the past few years. The utilities seem to be capturing this to some degree in their demand outlooks, as each year they include the new (presumably higher) level of returning customers.

#### 2.3.4.1.3 Economic growth, output, or income is explicitly tracked in some design day outlooks

Some GDCs provided specific information about how their assumptions for economic growth affect design day outlooks:

- **ETG:** as noted above, ETG's regression model incorporates a time trend variable "t" which cannot isolate the separate impact of economic growth, output, or income over time;
- **PSE&G:** in its 2020 BGSS filing, PSE&G used Moody's Economy March 2019 forecast, which assumes that the US economy recovers at "a slow but steady rate" and that New Jersey's economic outlook also follows the national forecast. PSE&G's gas sales forecast notes: "assumptions about future prices and local economic and demographic parameters were utilized to produce a forecast of billed natural gas delivered sales by rate for the residential, commercial, and industrial customer classes."<sup>46</sup> This translates into growth in income, which drives increases in usage per customer in the RSG model.<sup>47</sup> The economic setback to the US economy in 2020 from Covid-19 implies that the income-based portion of PSE&G's 2020 outlook is probably too high; PSE&G's 2021 outlook might capture this impact. For the commercial sector model, PSE&G uses growth in output (which is represented by proxy variables: household income and number of households) as a driver of demand;
- **NJNG:** NJNG reported that its firm demand forecast is based on the historical trends of customer growth in eight different statistical models.<sup>48</sup> NJNG was not specific in response to data requests as to which drivers are included in which models; and
- **SJG:** SJG was not specific in response to data requests or in its 2020 BGSS filing about which drivers are included in the forecasting model.<sup>49</sup>

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<sup>46</sup> Public Service Electric & Gas Company. *Natural Gas Sales Forecast -2020*. May 2020. p. 14.

<sup>47</sup> Public Service Electric & Gas Company. *Natural Gas Sales Forecast -2020*. May 2020. p. 3.

<sup>48</sup> Response to DR 1.4: New Jersey Natural Gas. BPU Docket No. GO20010033. 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. Discovery Response. February 24, 2021.

<sup>49</sup> SJG response to DR 1.7: South Jersey Gas. BPU Docket No. GR20010033. 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. Discovery Request. February 26, 2021.

#### 2.3.4.1.4 Some, but not all design day outlooks account for future energy efficiency

The four GDCs implement state-run energy efficiency programs as well as programs adopted by the individual GDCs, and account for the impacts in a variety of ways.

- **ETG:** ETG's variable "t" captures the impact of any and all trends over time, so does not explicitly account for historical trends in efficiency.<sup>50</sup> For its outlook, ETG simply assumes that the impact on usage per customer from conservation and energy efficiency initiatives is offset by growth in new residential and commercial customers;<sup>51</sup>
- **NJNG:** NJNG includes energy conservation savings that are embedded in historical data (which reflects the Conservation Incentive Program ("CIP") and New Jersey's Clean Energy Program ("NJ CEP")).<sup>52</sup> The potential effects of the NJ CEP do not appear to be included in design day demand going forward (which implies that future efficiency impacts are assumed to be the same as historical impacts);<sup>53</sup>
- **PSE&G:** PSE&G explicitly accounts for the impact of efficiency programs.<sup>54</sup> The demand forecast includes both their Clean Energy Future - Energy Efficiency ("CEF-EE") Program and the state-run programs in the Clean Energy Act. PSE&G reports that these programs lower design day demand by 0.6% (17 MDth/d) in 2021 compared to what they otherwise would have been; and by 2.1% (64 MDth/d) compared to otherwise in 2025;<sup>55</sup> and
- **SJG:** SJG reports CIP volumes of 124,272 Dth/d in 2019 and projects the same annual amount from 2021 through 2030. By 2025, design day sendout is 578,758 Dth/d, and by 2030 it is 672,099 Dth/d.<sup>56</sup> In other words, the efficiency impacts are incorporated into the outlooks, but are assumed to be unchanged from 2019.

#### 2.3.4.1.5 LAUF gas is a very small portion of demand

LAUF gas is defined as "the difference between the gas injected into a distribution system and the gas measured at customers' meters. LAUF gas is the result of measurement and accounting errors, stolen gas, and pipe leaks."<sup>57</sup> LAUF gas is a small share of demand:

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<sup>50</sup> ETG response to DR 1.1: Elizabethtown Gas. BPU Docket No. GR20010033. 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. Discovery Request. March 12, 2021.

<sup>51</sup> Response to DR 1-3 and DR 1-4 Elizabethtown Gas. BPU Docket No. GR20060381. 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. Discovery Request. March 12, 2021.

<sup>52</sup> NJNG response to DR 1.6 "02-24-2021 NJNG GR20010033 BGSS Gas Capacity Discovery Responses to BPU only."

<sup>53</sup> Ibid.

<sup>54</sup> Public Service Electric & Gas Company. *Natural Gas Sales Forecast -2020*. May 2020. P. 16.

<sup>55</sup> PSE&G response to DR 1.5 "02-24-2021 PSE&G GR20010033 Response to Discovery Request: S-PSEG-0001."

<sup>56</sup> SJG response to DR 1.7 "SJG Gas Cap & Related Issues Discovery Responses (02 21)s."

<sup>57</sup> Costello, Ken. "Lost and Unaccounted for Gas: Practices of State Utility Commissions." *National Regulatory Research Institute*. June, 2013.

- **ETG:** LAUF gas accounted for 1.6% of total forecasted design day demand;<sup>58</sup>
- **NJNG:** LAUF gas <1% (including “company use and unaccounted for gas”);<sup>59,60</sup>
- **PSE&G:** LAUF gas is not explicitly accounted for, but is implicitly included in design day sendout (if 1% of demand, it would amount to 30 MDth/d in 2022/23); and
- **SJG:** LAUF gas is not explicitly accounted for, but is implicitly included in the design day sendout.

#### 2.3.4.1.6 Reserves to cover loss of load probability (“LOLP”) are not a trivial quantity

LOLP is defined as the “probability that demand exceeds supply within a period of time.”<sup>61</sup> PSE&G and NJNG each include a separate line in their BGSS design day firm demand outlooks that includes a 3% LOLP. LOLP is measured in days per year, so a 3% LOLP means there is enough reserve firm supply above design day firm demand that the utility would only fall short 3% of the time, or 1 day in 33 years.<sup>62</sup>

LOLP reserves are not trivial. For NJNG and PSE&G combined, they add up to 346 MDth/d:

- **ETG:** does not mention LOLP;
- **NJNG:** LOLP amounts to 185 MDth/d in each year;
- **PSE&G:** LOLP amounts to 161 MDth/d in each year; and
- **SJG:** does not mention LOLP.

The LOLP totals are not included in Figure 21 or Figure 22, nor are they included in the Levitan Report’s firm demand numbers discussed later in this report in Section 3.2. Similarly, LEI does not include LOLP in its design day firm demand outlooks, because LEI discusses such a loss in terms of a supply incident/emergency in Section 5, Best Practices and Playbook.

### 2.3.5 The GDCs’ 1.02% CAGR for design day firm demand is too high

LEI’s analysis shows that the GDCs’ 1.02% CAGR for design day firm demand from 2020 to 2030 is too high for several reasons. First, as shown previously in Figure 19, it is not based on the historical trend in demand per HDD of 0.95% CAGR annually. Second, two GDCs, NJNG and

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<sup>58</sup> ETG. *In the Matter of the Petition of Elizabethtown Gas Company to Review its Periodic Basic Gas Supply Service Rate: Case Summary, Petition, Testimony and Schedules*. June 1, 2020.

<sup>59</sup> Per NJNG response to LEI’s data request, “NJNG’s design day forecasting is performed on a Sendout basis rather than a customer-metered basis. The Design Day Sendout forecast is based on historical actual citygate volumes and LAUF is embedded in those citygate volumes. Since NJNG does not have daily meter reads for all of its customers, the daily LAUF quantity is not available for design day forecasting.”

<sup>60</sup> NJNG. *In the Matter of New Jersey Natural Gas Company’s Annual Review of Its Basic Gas Supply Service (BGSS) and Conservation Incentive Program (CIP) Rates for F/Y 2021*. June 18, 2020

<sup>61</sup> Costello, Ken. “Increased Dependence on Natural Gas for Electric Generation: Meeting the Challenge.” *The National Regulatory Research Institute*. 2004

<sup>62</sup> PSE&G response to DR 1.2 “02-24-2021 PSE&G GR20010033 Response to Discovery Request: S-PSEG-0001.”

ETG, assume efficiency will not improve in the future relative to the past. And third, two GDCs rely on customers switching from oil to natural gas for a portion of demand growth, even though this practice is likely to slow given public policies which encourage electrification rather than switching to natural gas heating.

In the following sections, LEI develops alternative scenarios of design day firm demand, which reflect historical trends in demand per HDD, and New Jersey clean energy programs going forward.

### **2.3.6 LEI scenario outlooks for design day firm demand**

LEI's scenarios reflect historical growth in weather-normalized peak demand (as discussed in Section 2.3.3), GDC projections of design day demand (as discussed in Section 2.3.4), energy efficiency requirements, and state decarbonization goals.

#### **2.3.6.1 Framing the role of energy efficiency requirements**

The Board Order directed each electric and gas public utility in the State to establish energy efficiency and peak demand reduction programs to comply with the energy efficiency provisions of New Jersey's Clean Energy Act of 2018 ("CEA").<sup>63</sup>

Though the efficiency targets are set out in terms of annual energy savings, for reliability, the demand that is of interest is peak day demand, not annual energy consumption. In this section, LEI maps the Board Order's energy efficiency targets to expected reductions in peak demand based on the report *Energy Efficiency Potential in New Jersey*, prepared for the BPU by Optimal Energy and dated May 24, 2019 (referred to as the "Market Potential Study"). LEI also projects energy efficiency improvements from 2026 to 2030 based on the maximum achievable reductions as defined in the Market Potential Study.

##### **2.3.6.1.1 Efficiency targets through June 2026 reflect the Board Order**

The CEA directed the Board to require "[e]ach natural gas public utility to achieve, within its territory by its customers, annual reductions in the use of natural gas of at least 0.75% of the average annual natural gas usage in the prior three years within five years of implementation of its gas energy efficiency program."<sup>64</sup>

In addition to the 0.75% reduction, which must be achieved by the utility by the fifth program year (i.e., the year ending June 2026) based on its own programs, the utility must also achieve additional energy efficiency savings based on the state-wide programs (the New Jersey Clean Energy Program) administered by the Board's Division of Clean Energy ("DCE").<sup>65</sup> Together these amount to a total reduction of 1.10% in annual natural gas consumed by program year 5 ("PY5") (see Figure 23).

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<sup>63</sup> NJ BPU. *Order Directing the Utilities to Establish Energy Efficiency and Peak Demand Reduction Programs* (Docket Nos. QO19010040, QO19060748, and QO17091004). June 10, 2020.

<sup>64</sup> *Ibid.* p. 2.

<sup>65</sup> *Ibid.* pp. 20-22.



**Figure 23. New Jersey CEA energy efficiency reduction targets for the GDCs (net savings as % of retail sales)**

Month/year	Program year	State-administered program annual savings target +	Utility program annual energy savings target =	Total utility-specific annual energy use reduction target
July 2021/June 2022	PY1	0.00%	0.00%	0.00%
July 2022/June 2023	PY2	0.16%	0.34%	0.50%
July 2023/June 2024	PY3	0.24%	0.51%	0.75%
July 2024/June 2025	PY4	0.30%	0.65%	0.95%
July 2025/June 2026	PY5	0.35%	0.75%	1.10%

Source: NJ BPU. *Order Directing the Utilities to Establish Energy Efficiency and Peak Demand Reduction Programs* (Docket Nos. QO19010040, QO19060748, and QO17091004). June 10, 2020. P. 20-22.

Energy efficiency improvements which reduce annual consumption can also reduce peak demand, especially when such improvements impact heating equipment and building efficiency. The Market Potential Study calculated coincident peak day savings targets in billion Btus (“BBtu”), which correspond to the net annual total efficiency targets for the GDCs (see Figure 24).

**Figure 24. Peak day gas demand reduction recommendations from Market Potential Study**

Program year	Total annual Board energy savings target	Peak-day demand reductions corresponding to Board energy savings target (BBtu)	Total firm peak day demand, per utilities' 2020 BGSS filings (MDth/d)	Percent of total peak day demand
PY1 (2021/22)	0-0.25%	14.8	5,091.8	0 to 0.29%
PY2 (2022/23)	0.50%	26.6	5,160.6	0.52%
PY3 (2023/24)	0.75%	38.5	5,236.7	0.74%
PY4 (2024/25)	0.95%	56.5	5,297.7	1.07%
PY5 (2025/26)	1.10%	66.1	n/a	n/a

Sources: NJ BPU. *Order Directing the Utilities to Establish Energy Efficiency and Peak Demand Reduction Programs* (Docket Nos. QO19010040, QO19060748, and QO17091004). June 10, 2020. p. 20-22; Optimal Energy. *Energy Efficiency Potential in New Jersey*. May 24, 2019. P. 88 and 102-103.

Note: Program year one (PY1) begins in 2021 for the Board energy efficiency reductions, and requires zero reductions, whereas the Market Potential Study assumed the first year of energy savings would correspond with a Board target of 0.25% reduction. Therefore, for the purposes of this analysis, LEI assumed the reduction would be in the range of 0-14.8 BBtu, i.e., 0-0.25%.

Note: For this Figure, LEI excluded the impact of CEA conservation and efficiency programs reported by PSE&G in PSE&G’s projections of firm design day demand (see response to DR 1-005) to avoid double-counting. The other GDCs did not provide breakouts of projections with and without CEA impacts.

The Market Potential Study did not provide an outlook for peak day demand, and so did not provide a percentage reduction associated with the BBtu reduction. To calculate the implied percentage reduction, LEI referred to total design day firm demand projected by the four GDCs in their BGSS filings. By PY4, the 0.95% annual energy savings target corresponds to the Market Potential Study’s 56.5 BBtu reduction in peak demand, or a reduction of 1.07% from the design day outlook of the GDCs. As discussed earlier, design day firm demand is much higher than

historical firm peak demand; this implies that the percent of peak demand savings in a typical year will be greater than the percentages shown in the last column of Figure 24.

2.3.6.1.2 Efficiency targets can be higher, based on maximum achievable potential

The CEA also allows the Board to mandate energy efficiency reductions that exceed 0.75% for natural gas utility programs, “pursuant to the market potential study until the reduction in energy usage reaches the full economic, cost-effective potential in each service territory, as determined by the Board.”<sup>66</sup> The Market Potential Study defines “maximum achievable potential” as “the maximum level of program activity and savings possible, given market barriers to adoption of energy-efficient technologies, and including administrative costs necessary to implement programs.”<sup>67</sup>

For the purposes of developing scenarios, LEI assumed Board targets for 2027-2030 would be about 30 BBtu lower than the Maximum Achievable Potential, based on the difference between Board targets and the Maximum Achievable Potential from 2021-2026 (see Figure 25).

**Figure 25. Board peak day demand reduction and Maximum Achievable Potential reductions, BBtu**

Year	Program year if applicable	Board Target*	Maximum Achievable Reduction
2021	PY1	14.8	50.0
2022	PY2	26.6	54.5
2023	PY3	38.5	77.2
2024	PY4	56.5	86.4
2025	PY5	66.1	95.4
2026		68.4	98.4
2027		70.6	100.6
2028		72.8	102.8
2029		74.8	104.8
2030		76.4	106.4

Source: Maximum achievable reduction, Market Potential Study, Appendix Tables 5-8.

\*LEI assumption that Board targets for 2027-2030 would be about 30 BBtu lower than the Maximum Achievable Potential, based on the difference between Board targets and the Maximum Achievable Potential from 2021-2026.

<sup>66</sup> NJ BPU. *Order Directing the Utilities to Establish Energy Efficiency and Peak Demand Reduction Programs* (Docket Nos. QO19010040, QO19060748, and QO17091004). June 10, 2020. p. 3.

<sup>67</sup> Optimal Energy. *Energy Efficiency Potential in New Jersey*. May 24, 2019. p. 5.

### 2.3.6.2 Overview of LEI's design day firm demand scenarios

In this section, LEI describes its approach to measuring changes in firm demand driven by energy efficiency and the potential impacts of other State programs supporting New Jersey's zero-carbon goals.

#### 2.3.6.2.1 Incorporating existing energy efficiency programs

According to the Market Potential Study, current efficiency programs save approximately 0.2% of total gas sales.<sup>68</sup> LEI assumed this 0.2% of annual sales corresponds to 0.2% of peak demand in the GDCs outlooks. In other words, if no energy efficiency programs were in place, the GDC's 2020 BGSS outlook would show a 1.22% growth in design day demand to 2024/25 (relative to current projections of 1.02%, as discussed in Section 2.3.4). Similarly, if no energy efficiency programs were in place, historical peak demand would have grown 1.15% per year, not 0.95% per year.

#### 2.3.6.2.2 Building electrification: the potential game-changer

New Jersey's EMP includes decarbonization and electrification of buildings by 2050.<sup>69</sup> The EMP recommended a number of approaches the state should take to electrify the building sector, including electrifying state facilities; partnering with private industry to establish electrified building demonstration projects; expanding and accelerating current statewide net zero carbon home incentive programs for both new construction and existing homes; studying and developing mechanisms and regulations to support net-zero carbon new construction; incentivizing the transition to electrified heat pumps, hot water heaters, and other appliances; and developing a transition plan to a fully electrified building sector. The EMP noted that "*NJ BPU should also provide incentives for natural gas-fueled properties to transition as well as terminate existing programs that incentivize the transition from oil heating systems to natural gas heating systems.*"<sup>70</sup>

Through 2030, the EMP projects that in the Integrated Energy Plan ("IEP") Least Cost scenario, the first wave of electrification of space and water heating reduces annual consumption of pipeline natural gas by the residential, commercial, and industrial sectors in total to 306 MDth/d by 2030 (see Figure 26).<sup>71</sup> This amounts to a decline of 2.4% per year from 2020 to 2030. Because heating services drive the 2.4% decline in annual consumption, it is likely to have a similar impact on peak demand needs.

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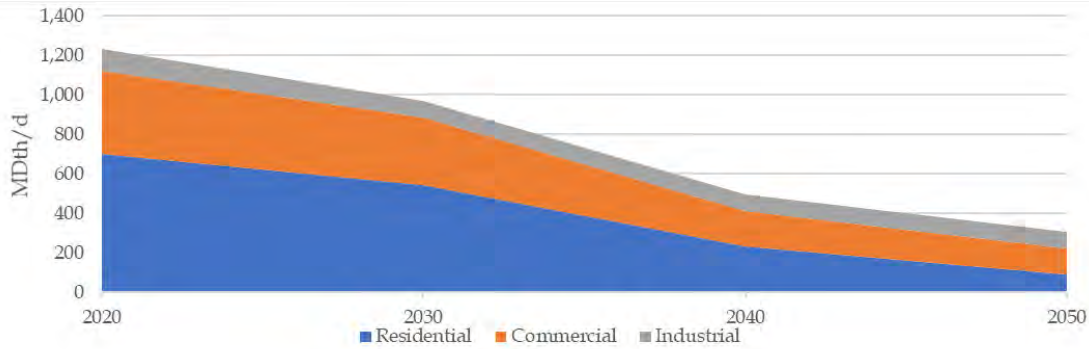
<sup>68</sup> Ibid. P. 45.

<sup>69</sup> New Jersey. *2019 Energy Master Plan: Pathway to 2050*. January 27, 2020. p. 157.

<sup>70</sup> Ibid. P. 167.

<sup>71</sup> Evolved Energy Research. *New Jersey 2019 IEP Technical Appendix*. November 29, 2019. P. 45-46.

Figure 26. Annual pipeline natural gas consumption, IEP Least Cost scenario



Source: Evolved Energy Research. *New Jersey 2019 IEP Technical Appendix*. November 29, 2019. p. 45-46.

Note: Original units of trillion Btu per year converted to MDth/d at 1Dth=1MMBtu.

### 2.3.6.3 Defining LEI's two Scenario Sets

In compliance with the CEA, the Board Order requires each GDC to reduce the use of natural gas *below what would have otherwise been used*.<sup>72</sup> The phrase “would have otherwise been used” implies a counterfactual must be created to use as a benchmark—the counterfactual establishes the energy consumption that would have occurred without the efficiency efforts.

In LEI's scenarios, LEI defines the counterfactual as the outlook for design day firm gas demand growth without the impact of new efficiency efforts or building electrification. This outlook, if based on the GDCs' projections, is 1.02% demand growth per year (with some caveats related to how the GDCs incorporate the impact of energy efficiency, discussed below). If based on an actual historical perspective, this counterfactual outlook is 0.95% demand growth per year. LEI used each of these two assumptions as the basis of a Scenario Set which encompasses five different assumptions about the impact of energy efficiency targets on peak demand.

As discussed in more detail below, the largest differences in the outlooks by 2030 reflect the difference in assumptions about building electrification (i.e., fuel-switching from gas to electric space and water heating).

#### 2.3.6.3.1 Scenario Set 1: Underlying peak demand grows at the 1.02% level projected by the GDCs

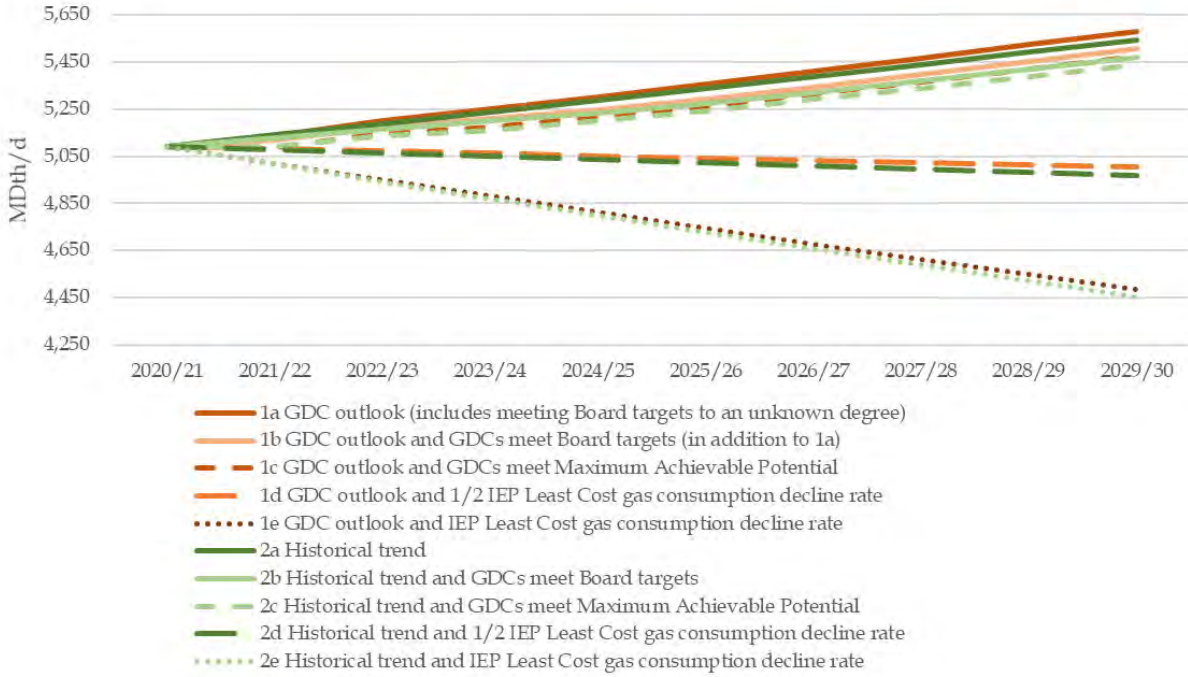
In Scenario Set 1, LEI defines “what otherwise would have been” as the projected 1.02% per year rate of growth assumed by the GDCs through 2025, and the same rate through 2030 (see Figure 27 and Figure 28

Scenario 1a reflects the GDCs outlooks for design day firm demand, including the impact of CEA conservation and efficiency programs explicitly included by PSE&G. The other utilities did not

<sup>72</sup> NJ BPU. *Order Directing the Utilities to Establish Energy Efficiency and Peak Demand Reduction Programs* (Docket Nos. QO19010040, QO19060748, and QO17091004). June 10, 2020. p. 30.

report impacts of conservation and efficiency separately in their design day firm demand outlooks, so LEI could not develop a “no conservation or efficiency” baseline. However, without the impact of CEA targets on PSE&G’s outlook, the CAGR for the GDC outlook in Scenario 1a would be 1.14% instead of 1.02%.

**Figure 27. LEI scenarios for design day firm demand**



Scenario	CAGR outcomes from 2020/21 to 2029/30
<b>Set one</b>	
1a GDC outlook (includes meeting Board targets to an unknown degree)	1.02%
1b GDC outlook and GDCs meet Board targets (in addition to 1a)	0.87%
1c GDC outlook and GDCs meet Maximum Achievable Potential	0.81%
1d GDC outlook and 1/2 IEP Least Cost gas consumption decline rate	-0.20%
1e GDC outlook and IEP Least Cost gas consumption decline rate	-1.42%
<b>Set two</b>	
2a Historical trend	0.95%
2b Historical trend and GDCs meet Board targets	0.80%
2c Historical trend and GDCs meet Maximum Achievable Potential	0.74%
2d Historical trend and 1/2 IEP Least Cost gas consumption decline rate	-0.27%
2e Historical trend and IEP Least Cost gas consumption decline rate	-1.49%

Figure 28. LEI scenarios for design day firm demand, MDth/d numerical detail

Scenario	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30
<b>Set one</b>										
	<b>MDth/d</b>									
1a GDC outlook (includes meeting Board targets to an unknown degree)	5,092	5,135	5,200	5,249	5,303	5,357	5,412	5,468	5,523	5,580
1b GDC outlook and GDCs meet Board targets (in addition to 1a)	5,092	5,120	5,173	5,210	5,247	5,291	5,344	5,397	5,451	5,505
1c GDC outlook and GDCs meet Maximum Achievable Potential	5,092	5,085	5,145	5,171	5,217	5,262	5,314	5,367	5,421	5,475
1d GDC outlook and 1/2 IEP Least Cost gas consumption decline rate	5,092	5,082	5,072	5,062	5,052	5,042	5,032	5,022	5,012	5,002
1e GDC outlook and IEP Least Cost gas consumption decline rate	5,092	5,020	4,950	4,880	4,811	4,744	4,677	4,611	4,546	4,482
<b>Set two</b>										
	<b>MDth/d</b>									
2a Historical trend	5,092	5,140	5,189	5,238	5,288	5,338	5,389	5,440	5,492	5,544
2b Historical trend and GDCs meet Board targets	5,092	5,125	5,162	5,200	5,232	5,272	5,321	5,370	5,419	5,469
2c Historical trend and GDCs meet Maximum Achievable Potential	5,092	5,090	5,134	5,161	5,202	5,243	5,291	5,340	5,389	5,439
2d Historical trend and 1/2 IEP Least Cost gas consumption decline rate	5,092	5,078	5,064	5,051	5,037	5,024	5,010	4,997	4,983	4,970
2e Historical trend and IEP Least Cost gas consumption decline rate	5,092	5,017	4,942	4,869	4,797	4,726	4,657	4,588	4,520	4,453

Note: All scenarios start in 2020/21 with projections of design day firm demand of 5,092 MDth/d (the total provided by the GDCs). This total includes Retail Choice customers. Therefore, LEI’s outlook for firm demand in all scenarios includes Retail Choice customers.

For Scenario 1a, LEI extended the 1.02% growth that the GDCs are projecting in their 2020 BGSS outlooks for firm gas demand, to 2029/30. This sets the extreme high-end of the Scenario Sets, for two reasons:

- 1) It assumes that design day demand will grow faster than the historical weather-normalized (demand per HDD) annual growth rate from 2016-2020. LEI employs it here to set the upper bound of design day firm demand growth.
- 2) It assumes that there is zero net effect from energy efficiency requirements other than what is already built into the GDC outlooks.

For Scenario 1b, LEI projects that the GDCs will meet Board energy reduction targets (third column in Figure 25) thereby reducing their forecasted 1.02% annual growth rate. This results in a peak demand growth rate of 0.87% from 2020/21 to 2029/30. To the extent that PSE&G and other GDCs have included the impact of Board targets already in their outlooks, the 0.87% may double-count the impact of Board targets, and actual firm demand growth could be higher.

For Scenario 1c, LEI projects that the GDCs will meet Maximum Achievable Potential reductions (shown previously in Figure 25). This reduces their 1.02% forecasted peak demand growth rate to 0.81% from 2020/21 to 2029/30.

**Insight from scenario development**

The LEI scenarios which incorporate the IEP Least Cost assumptions (Scenarios 1d, 1e, 2d and 2e) include building electrification. Whether the historical demand growth rate is 1.02% as in Scenario Set 1 or 0.95% as in Scenario Set 2, **the only scenarios in either set where demand declines are ones in which some amount of building electrification occurs.**

For Scenario 1d, LEI incorporates half the rate of decline in gas demand implied by the IEP Least Cost scenario to the 1.02% growth rate projected by the GDCs, for a net decline of 0.20% from 2020/21 to 2029/30.

For Scenario 1e, LEI incorporates the full rate of decline in gas demand implied by the IEP Least Cost scenario to the 1.02% growth rate projected by the GDCs, for a net decline of 1.42% from 2020/21 to 2029/30.

2.3.6.3.2 Scenario Set 2: New Jersey stays on underlying weather-normalized historical trend of 0.95% per year

In Scenario Set 2, LEI defines “what otherwise would have been” as the 0.95% per year annual historical rate of growth on the coldest days.

For Scenario 2a, LEI projects firm demand based on the historical trend of 0.95% per year per HDD on the coldest days. This assumption implies two things:

- 1) New Jersey does not experience either systematically colder or warmer peak winter days in the next ten years compared with 2016-2020.
- 2) There is zero net effect from new energy efficiency requirements.

For Scenario 2b, LEI projects that the GDCs will meet Board energy reductions in addition to the 0.95% growth rate that otherwise would have occurred. This results in a peak demand growth rate of 0.80% from 2020/21 to 2029/30.

For Scenario 2c, LEI projects that the GDCs will meet Maximum Achievable Potential reductions from the 0.95% annual growth rate that otherwise would have occurred. This results in a peak demand growth rate of 0.74% from 2020/21 to 2029/30.

For Scenario 2d, LEI incorporates half the rate of decline in gas demand implied by the IEP Least Cost scenario to the 0.95% historical growth rate, for a net decline of 0.27% from 2020/21 to 2029/30.

For Scenario 2e, LEI incorporates the full rate of decline in gas demand implied by the IEP Least Cost scenario to the 0.95% historical growth rate, for a net decline of 1.49% from 2020/21 to 2029/30.

### 2.3.7 Recommended scenario choice to include in Shortfall Risk Assessment

For the purposes of Section 4, the Shortfall Risk Assessment, LEI recommends using one of the positive-growth scenarios (1a, 1b, 1c, 2a, 2b, or 2c). A positive-growth scenario necessarily results in some risk of a shortfall, which ensures that the Risk Assessment exercise will incorporate the need for several different options to mitigate the risks. Using a scenario in which growth is flat or negative would amount to assuming the problem away.

However, there is no evidence that design day firm demand would grow at the GDCs' assumed 1.02% per year (Scenario 1a). That rate is higher than the historical experience and probably does not fully account for CEA targets going forward. Therefore, LEI recommends using Scenario 2b, with a growth rate in design day firm demand of 0.80% per year. By 2030, design day firm demand under Scenario 2b is 377.5 MDth/d higher than in 2020 (see Figure 28 shown previously).

#### Insight from scenario development

LEI assigned no probabilities to any scenario. It may be tempting to assume that a scenario which traces a "middle path" to the future (for example, Scenario 1d or Scenario 2d) describes the most likely future. Indeed, many forecasting projects intentionally define a middle outlook as a "base case," "reference case," or "business as usual case," with or without probabilities associated with it. That is not the situation here. The two scenarios (1d and 2d) that describe the middle path assume that substantial changes to the building stock occur very quickly. This is unprecedented and is by no means business as usual.

**Scenario 2b reflects historical experience, and it is conservative** in that it assumes GDCs meet only Board-level efficiency targets, not Maximum Achievable targets; and it is also conservative in that it assumes zero progress in building electrification for ten years. Scenario 2b provides a conservative baseline to frame the examination of approaches to meeting potential shortfalls and developing best practices to cope with an emergency.

The degree of success of electrification will define the extent to which new gas pipelines or non-pipeline alternatives will be required to serve design day demand, as discussed in detail in Section 4. If building electrification is well under way within the next three years or so, it may warrant re-examining the scenarios and referring to Scenarios 1d, 2d, 1e, or 2e to examine the risk of design day shortfalls. At the present time, the pace of electrification is unknown; the scenario exercise illustrates how important electrification is to future natural gas demand.

## 2.4 Non-pipeline alternatives: Demand-side and supply-side options

Non-pipeline solutions (or non-pipeline alternatives) are alternative means of reliably meeting natural gas demand that offset, defer, or avoid the need for investments in incremental pipeline capacity. NPAs vary in terms of their stage of development and deployment, ranging from solutions that have been implemented in the United States for over two decades (i.e., energy efficiency programs) to solutions that are still in an early stage of development (e.g., green hydrogen, defined in Section 2.4.2.2). The following section assesses NPAs in two categories:

- **demand-side solutions:** reduce natural gas demand from the customer-side of the meter, and include solutions such as energy efficiency improvements, demand response ("DR") programs, targeted electrification (usually electrifying heating through heat pump



technologies), as well as innovative rate design to encourage peak-shaving – these are discussed in Section 2.4.1; and

- **supply-side solutions:** increase the supply of natural gas or alternative fuels, such as renewable natural gas (“RNG”), green hydrogen, liquefied natural gas (“LNG”), or compressed natural gas (“CNG”), which can be injected into the pipeline system to meet customer demand – these are discussed in Section 2.4.2.

NPAs can also be categorized in alternative ways, aside from demand- versus supply-side solutions. For instance, they may be assessed by their ability to either (i) address **peak day constraints** or (ii) **reduce overall gas demand** throughout the year. In this case, demand response programs, as well as CNG and LNG would fall into the former category, while energy efficiency programs and targeted electrification would fall into the latter.<sup>73</sup>

This review concludes with Section 2.4.3, identifying which of the various NPAs used in other jurisdictions have been implemented by New Jersey GDCs to date. In Section 2.4.3.3, LEI provides preliminary hypothetical ranges (in MDth/d) for the potential aggregate impact of these NPAs, thus providing a starting point for discussion of the extent to which these solutions could meet capacity shortfalls.

LEI recommends the New Jersey examine the costs and benefits of types of NPAs to ensure what is eventually adopted are consistent with as many state goals as possible.

## 2.4.1 Demand-side solutions used in other jurisdictions

### 2.4.1.1 Energy efficiency

Natural gas EE programs offered by utilities are designed to reduce overall natural gas usage and reduce customer gas bills. These programs are offered in a multitude of formats, but often include one or more of the following elements:<sup>74, 75</sup>

- **cash rebates or other financial incentives:** incentives such as rebates, loans, grants, or bonds, which are designed to incentivize energy efficiency improvements through the replacement or upgrade of appliances, doors, windows, or thermostats. These financial incentives tend to promote adoption among households and businesses, as they can lower the upfront cost of such upgrades and shorten the payback period of these investments;
- **programs targeted at low-income households:** aimed at reducing low-income customers’ energy usage and cost burden, generally through some sort of weatherization

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<sup>73</sup> Environmental Defense Fund. *Aligning Gas Regulation and Climate Goals: A Road Map for State Regulators*. January 2021.

<sup>74</sup> American Council for an Energy-Efficient Economy. [The 2020 State Energy Efficiency Scorecard](#). December 2020.

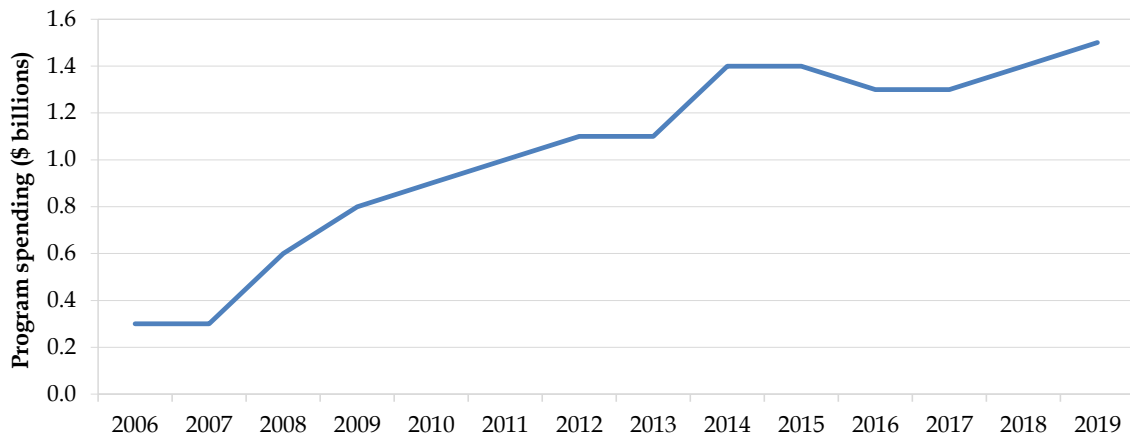
<sup>75</sup> American Gas Association. [Natural Gas Efficiency Programs Report: 2018 Program Year](#). July 2020.

component.<sup>76</sup> This involves installing insulation, as well as sealing cracks in ducts and walls to essentially weather-proof homes;

- **educational campaigns or targeted marketing:** outreach to raise awareness of ways that customers can reduce their natural gas usage, usually through brochures, bill inserts, and school education programs; and/or
- **energy audits and retrofit projects:** retrofit projects for houses or larger facilities often begin with energy audits, which involve a professional energy auditor assessing the home or facility and identifying areas where energy efficient solutions can be implemented.

Energy efficiency programs have existed in the United States since the late 1990s. The American Gas Association reports that around 30% of natural gas EE programs currently in effect have been in service for over 20 years.<sup>77</sup> Spending on these programs has grown substantially since they were first implemented, reaching \$1.5 billion in 2019 (see Figure 29).<sup>78</sup> Over the 2012 to 2017 period, the Lawrence Berkeley National Laboratory estimates that these utility programs achieved energy savings at an average cost to program administrators of 40 cents/therm (or \$4.00/Dth).<sup>79</sup>

**Figure 29. Utility spending on natural gas energy efficiency programs (billion nominal dollars)**



Source: American Council for an Energy-Efficient Economy. [The 2020 State Energy Efficiency Scorecard](#). December 2020.

<sup>76</sup> According to the US Department of Energy, the average cost of weatherizing a home is \$4,695. On average, this leads to \$283 in energy cost savings for a household annually, comprising of an 18% reduction in energy used for heating per year, as well as a 7% reduction in electricity consumption per year. (Source: US DOE. [Weatherization Assistance Program](#). January 2021.)

<sup>77</sup> According to a survey of 132 member and nonmember organizations identified by the AGA as large program administrators, reporting on natural gas efficiency programs conducted during the 2018 calendar year.

<sup>78</sup> American Council for an Energy-Efficient Economy. [The 2020 State Energy Efficiency Scorecard](#). December 2020.

<sup>79</sup> Lawrence Berkeley National Laboratory. [Energy Efficiency Continues to be Cheaper than Natural Gas](#). May 13, 2020.

### 2.4.1.2 Demand response

Compared to energy efficiency programs, natural gas demand response programs are still in their infancy, with many still being tested through pilot initiatives. Unlike energy efficiency programs, which seek to reduce total gas demand, DR programs seek to reduce demand on peak winter days, when the pipeline system is most constrained. Demand response programs can achieve these reductions in peak demand through various means, including:<sup>80</sup>

- **time-of-use tariffs:** utilities can induce changes in gas usage during peak demand days in response to prices or through incentive payments or time-of-use tariffs; and
- **direct load control:** whereby utilities can adjust customer natural gas usage on peak demand days by installing and controlling programmable thermostats in residential and commercial properties, or alternatively, by signaling to customers to switch off their furnaces or boilers.

One of the benefits of DR programs is their flexibility – utilities can call peak demand events and request customers across their service territory to reduce gas demand as needed. DR can be used to respond to weather events or unforeseeable force majeure pipeline-related outages, regardless of where or when the constraint occurs. The text box below highlights the experience of Southern California Gas Company (“SoCalGas”), one of the first utilities to implement gas DR programs in the US.

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<sup>80</sup> EIA. [Consolidated Edison gets approval for natural gas demand response pilot program.](#) November 2, 2018.

### Case study: SoCalGas Smart Therm Program

SoCalGas is the largest natural gas distribution utility in the United States, serving approximately 21.8 million customers throughout Central and Southern California. More than 90% of the utility's residential customers use natural gas primarily for heating, hot water, cooking, or drying clothes. In response to anticipated system stress resulting from this demand, SoCalGas first implemented gas DR programs during the 2016-2017 winter season. These programs included a rebate program with a smart thermostat element (the Smart Therm Program), as well as notification campaigns (among customers without smart thermostats), which sought to stimulate voluntary reductions in natural gas usage on peak demand days through mass media channels such as radio.

Under the Smart Therm Program, which continued through the 2017-2018 and 2018-2019 winter heating seasons, residential customers received up to \$75 to enroll their smart, internet-connected thermostats. Participants permitted SoCalGas to automatically adjust the temperature settings on their smart thermostats in response to peak demand events (called Smart Therm events). Smart Therm events were limited to no more than 25 events per heating season (between December 1 and April 1), each lasting up to four hours. During each event, customers were notified, and their thermostat settings were automatically reduced by a few degrees. Customers could opt out of each event via mobile device, web browser, or thermostat.

For the 2018-2019 program year, some 44,400 households participated in the program, enrolling 50,034 smart thermostats. Evaluation following the end of the heating season found that morning Smart Therm events (called between the hours of 5-9 am) led to aggregate event savings of 0.372 MMcf, or a 15.1% reduction in usage, while evening events (called between 6-10 pm) led to aggregate event savings of 0.076 MMcf. The discrepancy in average aggregate savings between the two types of events (morning versus evening) was largely owing to the number of participating customers – on average, 33,895 customers participated in the morning events, while only 9,208 customers participated in the evening events.

However, the savings were lower when considering load increases post-event. This effect is called the post-event “snap back” and refers to the increase in load following a savings event, where the customer's preferred temperature settings are restored. Including these effects, average aggregate daily savings declined to 0.207 MMcf for days where morning events were called, and to 0.031 MMcf when evening events occurred.

Sources: SoCalGas. [Company Profile](#); SoCalGas. [Frequently Asked Questions](#); CPUC. [Application of Southern California Gas Company to Establish a Demand Response Program](#). November 6, 2018; Energy Central. [Interview with Winner of AESP's 'Outstanding Achievement in Demand Response and Pricing' Award](#). May 6, 2019; Nexant. [2018-2019 Winter Load Impact Evaluation of SoCalGas Smart Therm Program](#). October 24, 2019.

#### 2.4.1.2.1 Time-of-use pricing to incentivize demand response

Under the current GDC tariff structure, residential BGSS customers in New Jersey are billed based on three separate charges:<sup>81</sup>

1. **a service/customer charge:** a fixed, minimum monthly charge (in dollars), which covers the cost to the utility for servicing the customer, including costs for metering, billing, and providing customer service;
2. **a commodity charge:** a variable charge (in dollars per therm) to recover the cost to the utility of purchased gas supply; and
3. **a distribution/delivery charge:** a capacity charge (in dollars per therm) associated with transmission and distribution capacity costs.

This type of rate design does not capture seasonal and daily variability, where peak periods are more expensive for utilities to supply than off-peak periods. Time-of-use (“TOU”) pricing addresses this misalignment between utility costs and traditional rate structures. TOU pricing is an innovative, cost-reflective tariff approach that has been utilized in the electricity sector to “dynamically recover energy costs and encourage load shifting.”<sup>82</sup> Under a typical TOU rate structure used in the electric sector, “the day is divided into time periods, which define peak and off-peak hours. Prices are higher during the peak-period hours to reflect the higher cost of supplying energy during that period.”<sup>83</sup> For the gas sector, peak periods are typically defined as days rather than hours, but the same logic applies.

Electric utilities have tested this pricing mechanism through numerous pilots, with several utilities offering this rate structure to customers on a permanent basis.<sup>84</sup> To date, TOU pricing has demonstrated promising results in terms of changes in customer behavior, specifically peak shaving. For example, a regression analysis of more than 60 time-varying pilots and 370 pricing treatments found that “residential customers reduce their on-peak usage by 6.5% for every 10% increase in the peak-to-off-peak price ratio.”<sup>85</sup>

TOU pricing could be applied to the gas sector as a potential NPA to reduce peak demand, but would require the installation of smart gas meters which can track the time of day in which consumption occurs. Gas bill components could then be shifted from the current rate structure to TOU pricing; generally, this would involve restructuring the commodity or energy charge such

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<sup>81</sup> See gas tariffs as of February 1, 2021 for each GDC: [ETG](#), [NJNG](#), [SIG](#), [PSE&G](#).

<sup>82</sup> Faruqui, Ahmad, and Cecile Bourbonnais. “The Tariffs of Tomorrow.” *IEEE Power & Energy Magazine* (May/June 2020): 18-25.

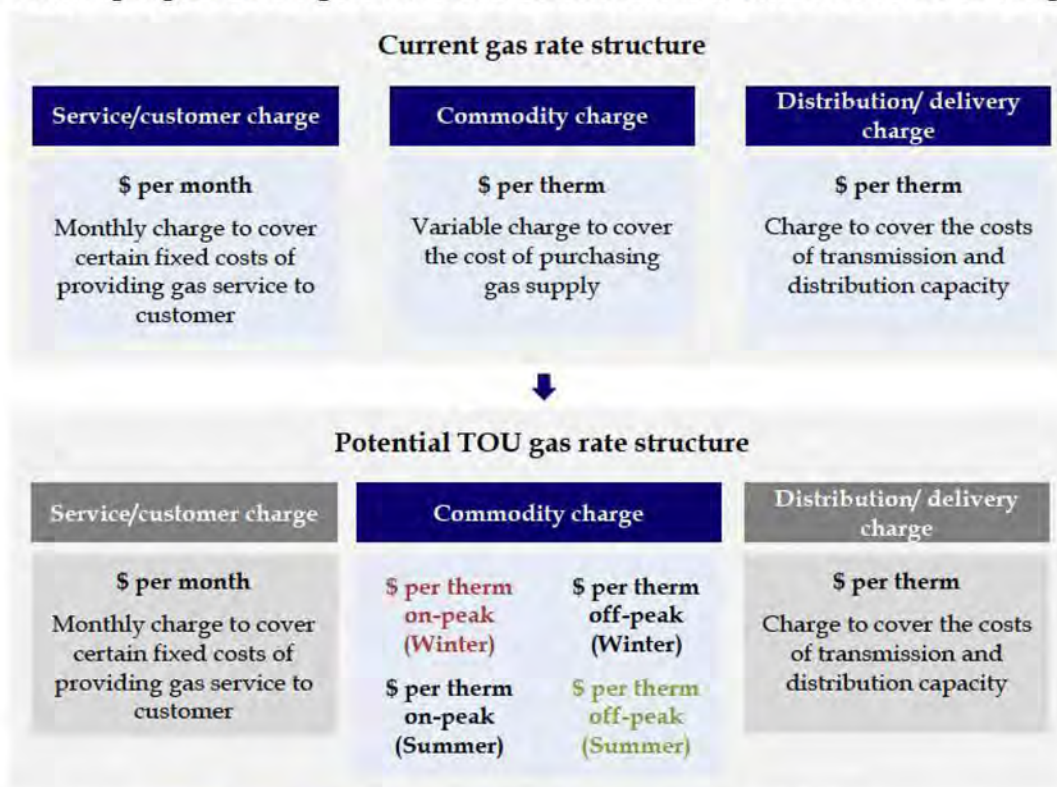
<sup>83</sup> Ibid.

<sup>84</sup> In the US, 322 utilities offer at least one form of time-varying rate to residential customers, with 5.5 million customers (or 4% of total residential customers) actively enrolled on these rates. (Source: Energy Regulation Quarterly. [Time of Use Rates: An International Perspectives](#), June 2020)

<sup>85</sup> Energy Regulation Quarterly. [Time of Use Rates: An International Perspectives](#), June 2020.

that it varies with time or season (e.g., higher rates during peak hours, peak days, or peak season) (see Figure 30).

Figure 30. Sample gas bill components under current rate structure versus time-of-use pricing



Source: Adapted from *Solving the rate puzzle: The future of electricity rate design*. March 8, 2019.

Although gas utilities have yet to implement a TOU pricing approach, local distribution companies (“LDCs”) in New York are being encouraged to explore innovative rate design (along with other NPAs) as part of their long-term gas system planning (see textbox).

#### 2.4.1.2.2 Direct load control

Direct load control of smart thermostats installed for all residential and commercial customers across all four GDCs would have the potential to shave peak demand substantially. A statewide direct load control program could be implemented as an emergency procedure, as discussed in detail in Section 5.

### Case study: Proposed changes to New York's long-term gas planning process

The New York Public Service Commission ("PSC") launched a proceeding (Case 20-G-0131) in March 2020 to explore possible changes to the state's natural gas planning procedures, with the goal of enabling "more comprehensive and more transparent planning by utilities for gas infrastructure and clean energy alternatives."

The New York State Department of Public Service ("DPS") filed a proposal in response to the proceeding in February 2021, outlining several potential modifications to the current long-term natural gas system planning process. First and foremost, the proposal emphasized the need for greater stakeholder engagement and education, as well as aligning gas system planning with New York's decarbonization efforts by increasingly meeting energy needs through electricity, renewable gas, and other fossil fuel alternatives. According to the DPS, this would "allow progress toward an "Integrated Resource Plan" for gas - a continuously updated model linking load, peak demand, costs, and investment opportunities for traditional natural gas solutions and for alternatives."

Specifically, under the proposed planning process, LDCs would be required to file long-term system plans every three years, covering a 20-year planning horizon. Among other filing requirements, utilities would be required to include a "no infrastructure option" to evaluate various NPAs, such as innovative rate structures.

On the matter of rate design, the DPS noted that "the LDCs should propose portfolios of demand response programs that not only include tried and true solutions, but also novel approaches, such as rate design changes. For example, seasonal rates or premium pricing on peak days may be effective at shaping demand. ... LDCs are encouraged to survey other jurisdictions and even other industries to determine more imaginative solutions to demand-supply gaps."

Sources: New York PSC. *PSC Launches Proceeding to Improve Transparency of Natural Gas Planning and Investments in New York*. March 19, 2020; New York Department of Public Service. *Staff Gas System Planning Process Proposal (Case 20-G-0131)*. February 12, 2021; S&P Global Market Intelligence. *With an eye to cutting gas use, NY regulator proposes utility planning overhaul*. February 16, 2021.

#### 2.4.1.3 Targeted electrification

Electrification of space and water heating presents another potential NPA, as it reduces peak day gas demand by switching customers over from gas-fueled heating to electricity. Electrification can be targeted by focusing efforts on neighborhoods where road openings for utility replacements are cost prohibitive when compared to electrification. By targeting electrification, the value of stranded gas assets can be minimized as customers switch to electricity, while avoiding the need to renew segments of certain natural gas assets.<sup>86</sup>

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<sup>86</sup> Environmental Defense Fund. *Aligning Gas Regulation and Climate Goals: A Road Map for State Regulators*. January 2021.

Electrification is primarily achieved through the installation of electric heat pumps, which fall into two main technology categories:<sup>87</sup>

- **air source heat pumps:** meet heating and cooling needs. In the winter, they gather heat from the ambient outdoor air, concentrate the heat via a compressor, and then move the heat inside through an indoor room unit to warm the space. Conversely, in the summer, air source heat pumps cool indoor spaces by gathering heat from the indoor air and moving it outside. Notably, on sub-zero temperature days, these systems usually require supplemental heat; and
- **ground source (or geothermal) heat pumps:** meet heating and cooling needs, and also provide hot water. Ground source heat pumps function along the same lines as air source heat pumps, except that heat is extracted from the ground or groundwater instead of from the ambient air. Unlike air source heat pumps, however, ground source heat pumps do not require a backup system.

In the northeast United States, electric heat pump deployment has “experienced limited growth due to high operating costs and concerns about cold weather performance.”<sup>88</sup> For example, the upfront cost and installation of an air source heat pump can often reach double the typical natural gas furnace cost.<sup>89</sup> But future costs will probably be lower: National Grid, in its Long-Term Gas Capacity report noted that heat pumps could reach cost parity with natural gas systems in the early 2030s.<sup>90</sup> Cost declines are expected to be driven by the following factors:

- **increased competition** among manufacturers and greater availability of heat pump models in the market;<sup>91</sup>
- **advanced research and development (“R&D”) activities** funded by the US Department of Energy Buildings Technology Office, which is expected to improve the cost and performance of heat pump technologies, including improving their performance in colder climates;<sup>92</sup> and
- **reduced installation costs** through lower labor costs, as contractors gain more experience installing these types of heating systems and begin to standardize system designs and installation procedures, requiring less customization.<sup>93</sup>

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<sup>87</sup> Efficiency Vermont. [Heat Pump Systems](#).

<sup>88</sup> National Grid. [Natural Gas Long-Term Capacity Report](#). February 2020.

<sup>89</sup> Ground source heat pumps are more expensive upfront than air source heat pumps because installation requires ground excavation. (Source: Efficiency Vermont. [Heat Pump Systems](#).)

<sup>90</sup> National Grid. [Natural Gas Long-Term Capacity Report](#). February 2020.

<sup>91</sup> Northeast Energy Efficiency Partnerships. *Northeast/Mid-Atlantic Air-Source Heat Pump Market Strategies Report 2016 Update*. January 2017.

<sup>92</sup> National Renewable Energy Laboratory. *Electrification Futures Study: End-Use Electric Technology Cost and Performance Projections through 2050*. 2017.

<sup>93</sup> Yale Center for Business and the Environment. *Feasibility of Renewable Thermal Technologies in Connecticut: A Field Study on Barriers and Drivers*. March 2017.



In Massachusetts, where more than half of households rely on natural gas as their primary energy source for space heating,<sup>94</sup> the state is exploring electrification via the use of heat pumps to meet the state's climate mitigation commitments (see textbox).

#### Case study: Massachusetts' heat pump initiatives

Heat pump incentives are available through programs administered by:

- **Mass Save:** offers a comprehensive set of statewide programs, including heat pump rebates of \$250 per ton of capacity for systems installed for residential customers, and integrated controls for customers using heat pumps alongside a central heating system;
- **the Massachusetts Clean Energy Center ("MassCEC"):** over the November 2014 to March 2019 period, MassCEC offered incentives for residential and commercial heat pumps, supporting over 20,000 projects throughout the state. Currently, MassCEC is focusing its efforts primarily on a residential whole-home air source heat pump pilot program, which offers rebates between \$2,500-\$5,000 for customers that convert from natural gas heating to a whole-home heat pump system; and
- **the Massachusetts Department of Energy Resources ("DOER"):** the DOER incentivizes heat pump adoption through the Alternative Portfolio Standard ("APS"), as well as the Home MVP, a three-year residential retrofit pilot program. Under the APS, residential customers completing a home retrofit with 90% or greater space heating from heat pumps can receive an upfront incentive between \$2,000 and \$3,000. The Home MVP offers numerous incentives, including zero-interest loans for non-fossil fuel measures, as well as rebates of around \$5,000 per home.

Source: American Council for an Energy-Efficient Economy. [Programs to Electricity Space Heating in Homes and Buildings](#). June 2020.

## 2.4.2 Supply-side solutions used in other jurisdictions

### 2.4.2.1 Renewable natural gas

Renewable natural gas is a "form of methane usable as fuel that comes from organic sources such as landfill waste, sludge, agricultural residue, and food waste" and is "considered to have greenhouse gas emissions reduction benefit due to its production from organic waste."<sup>95</sup> RNG is a pipeline-quality fuel that is interchangeable with conventional natural gas. In this sense, RNG can not only aid gas utilities in aligning their service with state-level decarbonization goals, but can also serve as an NPA by providing an alternative supply resource on peak winter days. Notably, RNG only works as a non-pipeline solution if it is locally produced or developed "on-system" (i.e., if it is produced and injected within the constrained portion of the pipeline system).

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<sup>94</sup> US EIA. [State Energy Profiles: Massachusetts](#). August 20, 2020.

<sup>95</sup> ConEdison. *Request for Information: Non-Pipeline Solutions to Provide Peak Period Natural Gas System Relief*. 2020.

RNG can generally be produced through one of the following technologies, which are in varying stages of development:<sup>96</sup>

- **anaerobic digestion:** the most widely used RNG production method in the United States, anaerobic digestion involves feeding organic material from dairies, farms, and landfills into a reactor, which produces biogas as a by-product. The biogas is then upgraded to biomethane (i.e., RNG), which can be injected into conventional natural gas pipelines;
- **thermal gasification:** where biomass is gasified under high temperature, producing syngas as a by-product, which is a mixture of gases such as hydrogen, carbon monoxide, steam, carbon dioxide, and most importantly, methane; and
- **power-to-gas (“P2G”):** involves electrolysis, direct air capture, and methanation, to produce and combine renewable hydrogen gas and carbon dioxide to create RNG. P2G technology is at a much earlier stage of deployment relative to anaerobic digestion, with P2G being used mainly in pilot and demonstration projects.

As of December 2020, RNG production capacity in the United States reached 161,643 MDth/d through 157 operating facilities, with a further 155 projects planned or under construction.<sup>97</sup> Several obstacles exist that may prevent its widespread production, including issues around scalability, accessibility, and production costs. Nonetheless, estimates of future US RNG deployment indicate large growth potential. The World Resources Institute estimates that RNG production from anaerobic digestion could yield between 780 Bcf to 1,400 Bcf of biomethane per year (equivalent to approximately 4-7% of current US natural gas consumption).<sup>98</sup> Separately, a 2019 report from the American Gas Foundation projects that RNG production costs could come down to the range of \$7-\$20/MMBtu by 2040, under a high resource potential scenario.<sup>99</sup>

The text box below presents two case studies: the first highlights a statewide initiative to promote RNG development in Oregon, while the second presents an example of an RNG program implemented by a utility based in Michigan, which offers its customers RNG supply for an additional fee.<sup>100</sup>

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<sup>96</sup> American Gas Foundation. *Renewable Sources of Natural Gas: Supply and Emissions Reduction Assessment*. December 2019.

<sup>97</sup> EnerKnol Research. *Renewable Natural Gas Emerging as Utility Decarbonization Strategy*. February 2, 2021.

<sup>98</sup> Including production from less mature technologies such as thermal gasification and P2G increases the yield estimate to 2,000 Bcf (or around 11% of current US natural gas consumption). (Source: S&P Global Market Intelligence. *Environmental, economic benefits to spur adoption of renewable gas, panel says*. January 27, 2021)

<sup>99</sup> American Gas Foundation. *Renewable Sources of Natural Gas: Supply and Emissions Reduction Assessment*. December 2019.

<sup>100</sup> This is a similar tactic to that used by utilities in the electric sector, where customers can opt-in to a higher rate to ensure their electricity supply is entirely (or partially) sourced from renewables. For example, community choice aggregators in California generally offer electric service at two levels: (i) default service with a 35-55% renewable electricity offering, or (ii) a more expensive 100% renewable electricity option. (Source: Clean Energy US. *CCAs and the Path to Local Economic Development and Energy Innovation: California Case Studies*)

### Case study: Oregon's statewide RNG initiative

In 2017, the Oregon Legislature passed Senate Bill 334. Under the Bill, the state's Department of Energy was tasked with developing, maintaining, and updating an inventory of biogas and RNG resources available in Oregon. The Department found that the state had the gross potential to produce nearly 50 Bcf of RNG per year through anaerobic digestion and thermal gasification, enough to meet over 20% of Oregon's total annual natural gas use.

In 2019, the state signed SB 98 into law, which set out an RNG program for gas utilities with voluntary portfolio procurement targets (e.g., securing 5% of gas for distribution to retail customers from RNG for 2020-2024, rising to 30% for 2045-2050). The legislation also directed the state's Public Utility Commission to adopt a rulemaking that would allow gas utilities to recover prudently incurred qualified investments through an automatic adjustment clause.

Cost recovery is capped, however, such that only up to 5% of a utility's revenue requirement may be used to cover the incremental cost of qualified investments in RNG infrastructure.

As of January 2021, the state had four gas-grid-connected RNG facilities under development. In addition, Northwest Natural Holding Co., Oregon's largest gas utility operator, has announced a partnership to produce 3,288 MMBtu of RNG per day.

Sources: Oregon Legislative Assembly. [Senate Bill 334](#). 2017; Oregon Legislative Assembly. [Senate Bill 98](#). 2019; S&P Global Market Intelligence. *Environmental, economic benefits to spur adoption of renewable gas, panel says*. January 27, 2021; Oregon Department of Energy. [Biogas and Renewable Natural Gas Inventory](#). September 2018.

### Case study: DTE Energy's RNG tariff

DTE Energy serves 2.2 million electricity customers in southeast Michigan and 1.3 million natural gas customers throughout the state.

Together, DTE Electric and Gas have committed to achieving net-zero carbon and greenhouse gas emissions by 2050. To further this goal, DTE Energy launched its CleanVision Natural Gas Balance Program in January 2021, which offers residential and small business customers a way to reduce their carbon footprint.

Under the program, participants receive both carbon offsets as well as RNG sourced from landfill emissions and wastewater treatment plant byproducts. Customers can participate in the program on an opt-in basis, and are able to select between four pricing tiers, ranging from \$4 to \$16 per month. Participation at the \$4/month level equates to a 25% offset in an average home's gas use emissions, while the highest tier of \$16/month fully offsets an average home's gas use emissions per month.

Sources: S&P Global Market Intelligence. *DTE Energy offers options for gas customers to cut their carbon footprint*. January 26, 2021.

## 2.4.2.2 Green hydrogen

Similar to RNG, green hydrogen can be used by gas utilities as a supply alternative on peak demand days (again noting that for green hydrogen to count as an NPA, it would need to be

developed “on-system” and within the identified pipeline constraint). Green hydrogen is produced via electrolysis, whereby renewable electricity is used to split water into oxygen and hydrogen.<sup>101</sup> However, unlike RNG, hydrogen is not fully interchangeable with conventional natural gas, and as such, must be blended before being injected into the natural gas pipeline system.<sup>102</sup>

Green hydrogen is also at a much earlier stage of development than RNG. It still faces several obstacles to deployment, most notably, cost. Per unit of energy, hydrogen supply costs are 1.5 to 5 times those of natural gas. Moreover, the economics of electrolysis – the method of producing hydrogen that can be powered by renewable resources – has yet to be tested at a large scale. According to the International Renewable Energy Agency (“IRENA”), hydrogen production from renewable power is not currently cost-competitive, but IRENA expects it to become increasingly competitive as the cost of electrolysis declines.<sup>103</sup> Several early-stage initiatives are underway by gas utilities across the US to blend hydrogen into their natural gas systems (see Figure 31).

**Figure 31. Early-stage hydrogen initiatives across gas utilities in the United States**

Utility	State	Initiative
Sempra Energy	California	Announced plans to introduce a 1% blend of green hydrogen into its natural gas stream, with aspirations to reach a 20% blend at its two California utilities
Northwest Natural Holding Co.	Oregon	Developing a project to produce green hydrogen and pair the locally produced supplies with carbon dioxide to create synthetic natural gas
Dominion Energy Inc.	Utah	Conducting a demonstration project to test hydrogen blends in pipeline systems, with plans to distribute synthetic natural gas made from green hydrogen
CenterPoint Energy Inc.	Minnesota	Readying a pilot project to produce green hydrogen and flow a less than 1% blend to customers through its gas distribution system
National Grid PLC	New York	Participating in a hydrogen blending study with Stony Brook University and the New York State Energy Research and Development Authority
Southern California Gas Co., One Gas Inc.	Texas	Participating in the US Energy Department's H2@Scale project to demonstrate commercial hydrogen production, distribution, storage, and consumption

Source: S&P Global. *How National Grid plans to advance US renewable gas, hydrogen development*. January 21, 2021.

<sup>101</sup> Although hydrogen can be produced using fossil fuels, we focus here on its production through electrolysis using surplus renewable electricity, which maintains its classification as a zero-emissions alternative fuel source.

<sup>102</sup> Hydrogen blending is the commingling of hydrogen produced through electrolysis or other industrial processes into the natural gas stream.

<sup>103</sup> IRENA. *Hydrogen: A Renewable Energy Perspective*. September 2019.

### 2.4.2.3 LNG and CNG trucking

Delivery of LNG<sup>104</sup> or CNG<sup>105</sup> via trucks is another NPA that can bypass pipeline constraints, to increase gas supply, and ensure reliable service is maintained for customers during peak periods. Also referred to as a “virtual pipeline,” this method involves loading and storing LNG or CNG in mobile containers (cryogenic containers in the former case, high-pressure containers in the latter), and transporting these containers to the point of use via truck. Once at the point of use, the LNG or CNG is regasified or decompressed and injected into the pipeline system.<sup>106</sup>

LNG and CNG trucking has been used by gas distribution companies for many years to cover potential shortfalls between supply and peak day demand, to serve as an emergency backup supply during pipeline ruptures<sup>107</sup> or scheduled inspections, or to bolster gas supply during extended cold snaps. It should be noted that this solution generally does not align with state-level and utility-committed decarbonization goals, owing to the increased GHG emissions associated with the handling and transportation of CNG and LNG. However, if limited to intermittent peak usage, these emissions can be minimized while also addressing potential supply shortfalls. The text box below highlights the case of National Grid, which has relied on trucked shipments of LNG and CNG in previous winter heating seasons to meet peak demand from its New York and New England customers.

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<sup>104</sup> LNG is natural gas that has been liquified by reducing its temperature to minus 260°F at atmospheric pressure.

<sup>105</sup> CNG is natural gas in high-pressure containers that is highly compressed (though not to the point of liquefaction).

<sup>106</sup> Modern Power Systems. [The LNG virtual pipeline: getting natural gas to places other pipelines can't reach](#). May 23, 2019.

<sup>107</sup> For example, FortisBC in British Columbia, Canada, utilized the virtual pipeline approach following a rupture of the Enbridge T-South pipeline in October 2018. The utility relied on trucked shipments of CNG to augment the supply of available natural gas for customers affected by the disrupted pipeline service (the virtual pipeline bypassed Enbridge's constrained transmission line and injected gas directly into FortisBC's distribution system). For approximately two months in the winter season, the utility used between 16-20 trucks per day to transport the CNG, serving approximately 12,000 homes over the duration of the program. (Source: FortisBC. [See how we're using a "virtual pipeline" to transport natural gas to the Lower Mainland](#). December 14, 2018)

### Case study: National Grid's use of virtual pipelines

National Grid serves approximately 3.6 million gas customers across the northeastern US, delivering gas to portions of upstate New York, New York City, Long Island, Massachusetts, and Rhode Island.

Over the 2019-2020 winter heating season, the utility relied on trucked shipments of LNG and CNG to temporary vaporization and decompression stations "to ensure supplies to customers in New York and New England during the coldest parts of winter."

Following a weather-related emergency in January 2019, where 7,500 customers lost gas supplies on Aquidneck Island, Rhode Island, National Grid mobilized a temporary LNG vaporization facility in Portsmouth, Rhode Island, to avoid future shortfalls. The facility was operated through the months of December 2019 and March 2020 and functioned as a back up to the gas supply serving the island.

In Long Island, National Grid operated two CNG facilities to ensure adequate peak day supply to customers in New York state. The facilities, located at Glenwood Landing and Riverhead sites, allowed up to 42 trucks per day in the 2019-2020 winter season to bring CNG from upstream of National Grid's system to "support minimum system pressures to all firm customers on the downstate New York systems." The Glenwood Landing facility supplied 1,000 Dth per hour at its peak, while the Riverhead facility supplied 1,100 Dth per hour.

In its Long-Term Capacity report, published in February 2020, the utility cited plans to identify a site for a third CNG facility in New York (to be operational for the 2021-2022 winter season), as well as plans to expand capacity at the two existing Long Island facilities to 108 trucks (increasing peak capacity from 17 MDth per day to 53 MDth per day).

Sources: National Grid. [US principal operations](#); National Grid. [Natural Gas Long-Term Capacity Report](#), February 2020; National Grid. [Natural Gas Long-Term Capacity Supplemental Report](#), May 2020; S&P Global Market Intelligence. [National Grid to use trucked LNG, CNG in peak US Northeast winter gas demand periods](#), November 11, 2019.

#### 2.4.2.4 Advanced leak detection

While advanced leak detection ("ALD") does not inherently represent a new or alternative source of natural gas supply, it is a technology that ensures that no natural gas is delivered into the system is wasted. Advanced leak detection minimizes the occurrence of LAUF gas.

According to the American Gas Association, LAUF gas "is the inevitable imbalance that exists at any given time between the measured gas coming into a utility distribution system and the measured gas going out of the same system."<sup>108</sup> This imbalance in gas volumes can be attributed to several factors, including operational factors such as line leakage. Although utilities fix hazardous leaks immediately and schedule non-hazardous leaks for repair, pipeline leakages still

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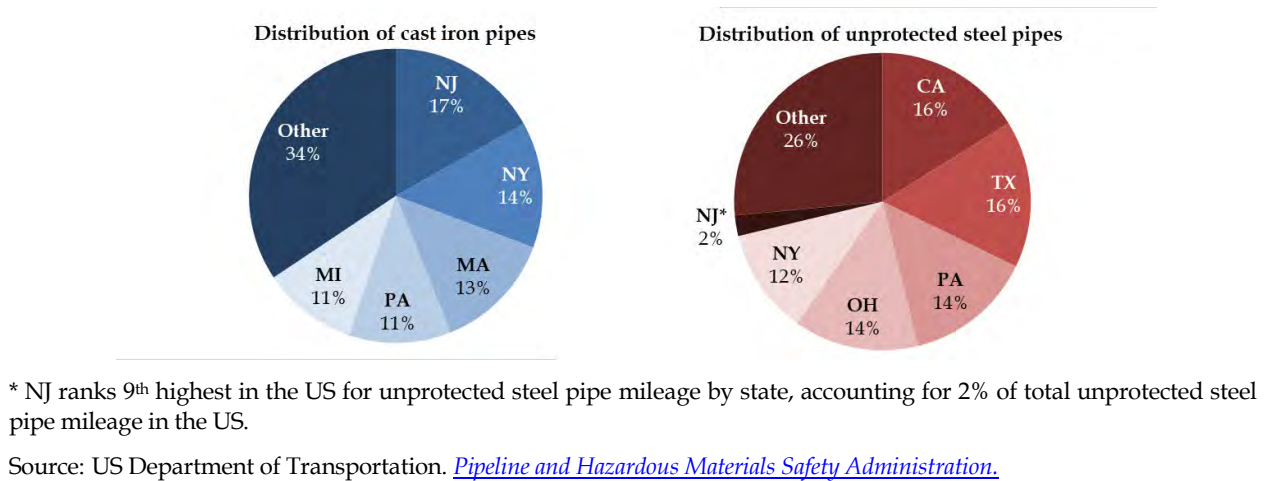
<sup>108</sup> American Gas Association. [Unaccounted for Natural Gas in the Utility System](#).

emit natural gas from the delivery system and contribute to LAUF gas, with larger volumes of gas lost, the greater the size of the leak and the higher the pressure on the system; this poses a safety risk and leads to increased methane emissions.

Before the use of ALD technology, utilities often relied on handheld methane detectors, Distribution Integrity Management Program (“DIMP”) surveys, or odor calls reported by customers or emergency first responders to detect pipeline leaks.<sup>109</sup> In contrast, ALD technology utilizes high sensitivity, mobile methane sensors, and data analytics to quantify leak flow volume more efficiently.<sup>110</sup> Specifically, ALD “refers to the use of high-sensitivity methane detection equipment capturing data at high frequency by mobile vehicles equipped with global positioning systems. The vast amount of collected data is processed through advanced analytics to estimate methane flow rate (e.g., in liters per minute) that can indicate system gas leaks.”<sup>111</sup>

Pipeline leaks are most common among cast iron and unprotected steel pipes, which are generally older and more likely to corrode and leak natural gas compared to other materials such as plastic or coated steel.<sup>112</sup> Although the number of miles of cast iron and unprotected steel pipes has declined significantly over the past three decades,<sup>113</sup> these leak-prone pipes still exist and are generally concentrated in the local gas distribution infrastructure in the northeast (see Figure 32).

**Figure 32. Miles of leak-prone pipes by top 5 states (2019)**



<sup>109</sup> Environmental Defense Fund. [Utility Use of Advanced Leak Detection to Maximize Cost Effective Methane Reductions](#). April 10, 2019.

<sup>110</sup> Ibid.

<sup>111</sup> Environmental Defense Fund. *Post-Hearing Brief of Environmental Defense Fund in Opposition to Joint Proposal in Case 19-G-0066*. December 6, 2019.

<sup>112</sup> US Department of Energy. [Natural Gas Infrastructure Modernization Programs at Local Distribution Companies: Key Issues and Considerations](#). January 2017.

<sup>113</sup> The mileage of cast iron pipe in the US has declined from 58,292 miles in 1990 to 21,273 miles by 2019 (down 64%). Similarly, the mileage of unprotected steel pipe has decreased from 108,941 miles to 50,280 miles (down 54%). (Source: US Department of Transportation. [Pipeline and Hazardous Materials Safety Administration](#))

### 2.4.3 Solutions currently underway in New Jersey

The following section explores the extent to which NPAs have been utilized by New Jersey's GDCs. New Jersey's involvement in non-pipeline solutions is analyzed first in terms of demand-side solutions (Section 2.4.3.1), followed by supply-side solutions (Section 2.4.3.2).

#### 2.4.3.1 Demand-side solutions

##### 2.4.3.1.1 Energy efficiency programs

GDCs first began offering energy efficiency programs to customers in 2009, in response to statutes passed to implement the Regional Greenhouse Gas Initiative ("RGGI") in New Jersey. Under Section 13 of the legislation, utilities were authorized "to provide and invest in energy efficiency and conservation programs in its service territory" and were allowed to "seek cost recovery for any such programs by filing a petition with the Board."<sup>114</sup>

In 2018, the Clean Energy Act was passed in the state, which among other efforts, expanded upon the 2008 RGGI legislation. The CEA directed the NJ BPU to require that "each natural gas public utility achieve annual natural gas usage reductions of at least 0.75%, relative to the average annual usage in its service territory, within five years of implementation of its gas energy efficiency program."<sup>115</sup>

GDCs filed proposals with the NJ BPU for energy efficiency programs pursuant to the CEA in September 2020, with programs to be implemented initially for a three-year period commencing on July 1<sup>st</sup>, 2021.<sup>116</sup> The EE programs proposed by the GDCs range from financial incentives, education efforts, and energy audits for residential customers, commercial and industrial ("C&I") customers, and those residing in multi-family buildings (see Figure 33). If approved by the NJ BPU, the GDCs project that these programs could result in total annual energy savings of nearly 7,000 MDth over the three-year period. Total budgets proposed by GDCs to implement these programs average \$175 million for each GDC (see Figure 34).

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<sup>114</sup> SJG. *In the Matter of the Petition of South Jersey Gas Company for Approval of New Energy Efficiency Programs and Associated Cost Recovery Pursuant to the Clean Energy Act*. September 25, 2020.

<sup>115</sup> Ibid.

<sup>116</sup> PSE&G submitted its proposed EE programs in response to the CEA on October 11<sup>th</sup>, 2018, and received Board approval on September 23<sup>rd</sup>, 2020. As such, PSE&G's EE programs began on October 1<sup>st</sup>, 2020, and will extend for a three-year period until September 30<sup>th</sup>, 2023. (Source: NJ BPU. *Order Adopting Stipulation: In the Matter of the Petition of Public Service Electric and Gas Company for Approval of its Clean Energy Future-Energy Efficiency ("CEF-EE") Program on a Regulated Basis*. September 23, 2020)



**Figure 33. Proposed energy efficiency programs by NJ GDCs**

Program	Description
<b>Residential</b>	
Efficient Products	Provides incentives for retail products, appliance rebates, HVAC equipment, and appliance recycling
Home Performance with ENERGY STAR	Provides incentives to encourage customers to pursue comprehensive upgrades to their home
Home Energy Reports/ Behavior	Involves behavioral initiatives and energy education
Quick Home Energy Check-Up (QHEC)*	Helps customers understand their best opportunities to save energy through an in-home consultation
Moderate Income Weatherization	Provides moderate income customers with no cost energy efficiency measures and upgrades
Energy Saving Trees*	Promotes planting of energy saving trees by residential customers
<b>Commercial &amp; Industrial (C&amp;I)</b>	
Direct Install	Provides a no-cost audit and direct install measures, and incentives for comprehensive retrofit projects
Prescriptive and Custom	Provides prescriptive and custom measures for lighting, HVAC, controls, and other C&I equipment
Energy Management	Provides incentives to C&I customers to more efficiently manage energy consumption at facilities
Engineered Solutions	Provides tailored energy efficiency savings for medium to large commercial customers, including municipalities, universities, schools, hospitals, and non-profit entities
<b>Other</b>	
Multi-Family	Addresses multi-family structures with three or more units

\* QHEC is proposed by ETG, NJNG, and SJG only. Energy Saving Trees is proposed by ETG and SJG only.

Sources: GDC energy efficiency filings.

**Figure 34. Projected annual energy savings and budgets for proposed EE programs**

Annual Energy Savings (therms)				
GDC	Year 1	Year 2	Year 3	Total
ETG	1,812,912	1,853,384	2,539,658	6,205,954
NJNG	3,785,807	4,181,061	4,122,859	12,089,727
PSE&G	12,425,905	19,736,673	11,701,416	43,863,994
SJG	2,007,669	2,081,342	2,738,402	6,827,413
<b>Total</b>	<b>20,032,293</b>	<b>27,852,460</b>	<b>21,102,335</b>	<b>68,987,088</b>

Estimated budget (\$ millions)*				
GDC	Year 1	Year 2	Year 3	Total
ETG	22	30	48	100
NJNG	80	86	92	258
SJG	45	49	73	167

\* PSE&G's budget is not reported separately for its electric and gas programs, and as such is excluded from the comparison.

Sources: GDC energy efficiency filings.

In addition to these GDC-led programs, New Jersey customers can also access state-administered energy efficiency and conservation programs through the New Jersey Clean Energy Program (see the text box).

### New Jersey Clean Energy Program

The New Jersey Clean Energy Program (“NJ CEP”) is administered by the NJ BPU’s Division of Clean Energy. It comprises “financial incentives, programs, and services for New Jersey residents, business owners, and local governments to help them save energy, money, and the environment.” Programs directed toward residential customers include, but are not limited to:

- **Residential New Construction** – new construction homes that are designed to be at least 15% to 50% more energy efficient than standard homes;
- **Appliance Rebates and Lighting** – rebates range from between \$25 and \$75 for qualified refrigerators, to up to \$300 for certified clothes dryers; and
- **New Jersey Comfort Partners** – intended for low-income customers, this program focuses on energy education, and also enables the free installation of energy saving measures to lower energy bills.

Programs designed for C&I customers, as well as local governments and multi-family buildings include, but are not limited to:

- **NJ Smart Start Buildings** – provides financial incentives for implementing energy efficiency measures through the installation of equipment from a pre-qualified list (e.g., heating and cooling systems, water heating, lighting and controls, etc.);
- **Pay for Performance** – allows customers with large existing and new facilities to work alongside a program partner to develop an Energy Reduction Plan, which comprises technical aspects, a financial plan, and a construction schedule for installation; and
- **Benchmarking** – provides energy managers and building owners with a performance assessment of their energy use at commercial, industrial, or municipal buildings.

Sources: NJ Department of State. [Business Assistance Programs: Energy Efficiency Programs & Incentives](#); NJ BPU. [New Jersey’s Clean Energy Program](#).

### High-end estimate of the impact of high-efficiency gas furnaces

How much peak day gas could be saved if all New Jersey residential customers instantly replaced the (assumed existing) average 78% efficient gas furnace with a 90% efficient furnace? A back-of-the-envelope calculation can provide a ballpark answer:

Gas demand from the residential sector in New Jersey in January 2020 was 1,460 MDth/d; in August 2020 it was 152 MDth/d. Assuming the entire difference was owing to space heating demand (ignoring water heating demand), then the gas used for space heating in February 2020 was the difference between the two months, or 1,308 MDth/d. If the 12% increase in efficiency of all furnaces translated directly to a 12% decline in heating demand in a peak month, the 12% decline would amount to 157 MDth/d.

This computation is simply a back-of-the-envelope analysis; it represents a high-end estimate because it does not account for the impact of water heating on winter versus summer demand for gas; not every customer will switch furnaces and certainly not all at once; and some customers may never replace a 78% efficient furnace with a 90% efficient furnace, owing to complications in installation requirements. If half of the furnaces were eventually replaced, the impact could be about half of LEI's estimate, or 78 MDth/d.

#### 2.4.3.1.2 Voluntary demand response programs proposed but not approved

Through the same 2020 filings whereby GDCs outlined new energy efficiency programs pursuant to the CEA, ETG and SJG proposed two pilot demand response programs to test over the three-year cycle, which would eventually inform potential future DR program offerings:<sup>117, 118</sup>

- **Residential Demand Response Pilot:** the proposed Residential DR Pilot is similar to the SoCalGas example presented in Section 2.4.1.2, in that ETG and SJG seek to test a direct load control approach to DR using internet-connected thermostats. Through the pilot, the GDCs will lower thermostat settings for participating customers by two degrees over a multi-hour period to reduce natural gas usage during peak events.

ETG and SJG expect that participating customers will initially comprise of residential customers that already have smart thermostats installed, who will be reached via direct mail and email marketing. Proposed incentives would reward customers for: (i) purchasing and installing smart thermostats, (ii) enrolling in the DR program, and (iii) successfully participating in the program based on the number of events per season; and

- **C&I Demand Response Pilot:** the proposed C&I DR Pilot will utilize a load curtailment approach, whereby larger C&I customers with firm transportation service will be called upon during peak periods “to reduce their usage over a 24-hour period after receiving a

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<sup>117</sup> ETG. *In the Matter of the Petition of Elizabethtown Gas Company for Approval of New Energy Efficiency Programs and Associated Cost Recovery Pursuant to the Clean Energy Act and the Establishment of a Conservation Incentive Program.* September 25, 2020.

<sup>118</sup> SJG. *In the Matter of the Petition of South Jersey Gas Company for Approval of New Energy Efficiency Programs and Associated Cost Recovery Pursuant to the Clean Energy Act.* September 25, 2020.

signal from the utility.” Customers will be encouraged to reduce their load through various methods, including shutting down certain processes, reducing central heating, or shutting down combined heat and power systems.

However, in separate BPU Orders dated April 7, 2021,<sup>119, 120</sup> ETG and SJG withdrew these proposed pilot programs as a result of settlement discussions. Going forward, if ETG and SJG are to secure gas usage reductions through voluntary DR programs, the GDCs will need to resubmit or propose new programs for Board approval.

#### 2.4.3.1.3 Targeted electrification

According to the US Energy Information Administration (using 2018 data), 75% of households in New Jersey rely on natural gas as the primary fuel for their space heating needs, while only 13% of households use electricity for space heating.<sup>121</sup>

As part of its 2020 energy efficiency filing, NJNG proposed a pilot Hybrid Heat (“HH”) Program to advance the state’s beneficial electrification efforts “without compromising customer comfort and reliability – at the customer and system level.”<sup>122</sup> Under the pilot program, NJNG will provide financial incentives to customers installing hybrid heat systems, which comprise of a high-efficiency gas furnace paired with a high-efficiency heat pump. NJNG expects customers to be those seeking to replace a gas furnace and an electric air conditioning unit; it expects that approximately 180 participants could be recruited by the end of the three-year pilot program.

In terms of financial incentives, the utility expects to provide customers with the following options to reduce cost barriers:<sup>123</sup>

- an upfront rebate of up to \$2,500; and
- eligibility to apply for a zero percent interest loan of up to \$15,000 over seven years through the On-Bill Repayment Program (“OBRP”).<sup>124</sup>

#### 2.4.3.2 Supply-side solutions

##### 2.4.3.2.1 Renewable natural gas and green hydrogen

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<sup>119</sup> NJ BPU. *Order Adopting Stipulation (Docket Nos. QO19010040 & GO20090619)*. April 7, 2021.

<sup>120</sup> Ibid.

<sup>121</sup> US EIA. [State Energy Profiles: New Jersey](#). September 17, 2020.

<sup>122</sup> NJNG. *In the Matter of the Petition of New Jersey Natural Gas Company for Approval of Energy Efficiency Programs and the Associated Cost Recovery Mechanism Pursuant to the Clean Energy Act*. September 25, 2020.

<sup>123</sup> Customers will be eligible for these incentives only after installing the necessary equipment and agreeing to participate in evaluation studies, which are necessary to inform the pilot program.

<sup>124</sup> The OBRP “ensures that customers who pay their utility bills on a timely basis have access to financing regardless of their credit scores or traditional screening ratios. (Source: NJNG. *In the Matter of the Petition of New Jersey Natural Gas Company for Approval of Energy Efficiency Programs and the Associated Cost Recovery Mechanism Pursuant to the Clean Energy Act*. September 25, 2020)

The American Gas Foundation reports that RNG production in New Jersey has the potential to reach an estimated 23 trillion Btu per year by 2040 under a low resource potential scenario, and up to 44 trillion Btu per year under a high resource potential scenario.<sup>125</sup> Although similar state-level estimates for green hydrogen production potential have yet to be assessed, utilities seem to be excited by the prospects of both types of alternative fuels.

GDC involvement in RNG and green hydrogen development to date has included investments in pilot and demonstration projects and announced financial commitments to further investments. NJNG's parent company, New Jersey Resources ("NJR"), and ETG's and SJG's parent company, South Jersey Industries ("SJI") are involved in the following projects:

- **NJR:** as part of its strategic capital spending plan through 2024, NJR expects to invest around \$24 million in RNG and green hydrogen projects in 2021, with a further \$20 million in investments in 2022.<sup>126</sup> NJR cited these investments as tools to achieve deeper reductions in its operational greenhouse gas emissions.<sup>127</sup>

NJR has already initiated a demonstration project in the Howell township of New Jersey, where solar energy will be used to produce green hydrogen through P2G technology. This hydrogen will then be blended and injected into NJNG's existing distribution network for residential and commercial use.<sup>128</sup> The project is expected to come online in 2021 and will be used by NJR "to study hydrogen blending capabilities and technology, raise awareness among regulators and policymakers and develop the expertise to scale up applications as the hydrogen market develops."<sup>129</sup>

NJNG became the first GDC to join the Coalition for Renewable Natural Gas when it signed on in August 2020. The Coalition comprises 250 member entities, who have joined forces to catalyze "the sustainable development, deployment, and utilization of renewable natural gas as a clean, safe alternative energy source";<sup>130</sup> and

- **SJI:** in December 2020, SJI announced its partnership with Atlantic Shores Offshore Wind. The entities are set to collaborate on a green hydrogen pilot program, which will utilize excess electricity generated from Atlantic Shores' offshore wind projects to produce green hydrogen. SJI will provide access to its natural gas infrastructure, which will be used to

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<sup>125</sup> Estimates include RNG production via two technologies (anaerobic digestion and thermal gasification) using eight types of feedstock: landfill gas, animal manure, water resource recovery facilities, food waste, agricultural residue, forestry and forest product residue, energy crops, and municipal solid waste. (Source: American Gas Foundation. *Renewable Sources of Natural Gas: Supply and Emissions Reduction Assessment*. December 2019)

<sup>126</sup> S&P Global Market Intelligence. [New Jersey Resources plots new strategy focused on renewable energy](#). November 30, 2020.

<sup>127</sup> NJR initially set a target of reducing its operational greenhouse gas emissions by 50% below 2006 levels by 2030, but recently increased the goal to 60% by 2030.

<sup>128</sup> Up Stream. [McDermott ramps up energy transition drive with US green hydrogen deal](#). February 3, 2021.

<sup>129</sup> S&P Global Market Intelligence. [New Jersey Resources plots new strategy focused on renewable energy](#). November 30, 2020.

<sup>130</sup> New Jersey Resources. [New Jersey Natural Gas Strengthens Sustainability Commitment with Membership in RNG Coalition](#). August 28, 2020.

“research, monitor, and analyze the deployment of hydrogen technology and natural gas blending in New Jersey.”<sup>131</sup>

#### 2.4.3.2.2 Advanced leak detection

Natural gas pipelines made from cast iron are characteristic of older gas infrastructure and have been found to be among the most leak-prone of the pipeline materials.<sup>132</sup> As of 2019, New Jersey’s GDCs accounted for the most distribution pipelines made from cast iron of any state in the US, totaling 3,911 miles of pipe.<sup>133</sup> This aging infrastructure presents a significant potential source for methane leaks; for example, approximately 30% of New Jersey’s total methane emissions stem from the natural gas transmission and distribution system.<sup>134</sup> In 2019, this equated to an estimated 2 million metric tons (“MMT”) of carbon dioxide equivalent (“CO<sub>2</sub>e”) emitted from pipeline leaks statewide per year,<sup>135</sup> or approximately 91 MDth/d.<sup>136</sup>

Although all GDCs are not currently implementing advanced leak detection technologies, the 2019 New Jersey EMP did call on the NJ BPU to “instruct all gas public utilities to incorporate advanced leak detection technology into operations to find, quantify, and prioritize gas pipeline repair and replacement and to file repair or replacement plans (or, in the alternative, non-pipeline solutions) with NJ BPU.”<sup>137</sup> Under Goal 5.4 of the EMP (to “maintain gas pipeline system reliability and safety while planning for future reductions in natural gas consumption”), ALD is emphasized as a means to not only enhance pipeline safety and reliability but also to meet the state’s emissions reductions goals.

To date, PSE&G and ETG have been most active in the space:

- **PSE&G:** PSE&G first began exploring the use of advanced leak detection technology through a pilot program that ran from 2015 through 2018. It used methane leak data to prioritize its pipeline replacement efforts. The pilot was approved by the NJ BPU as part of a \$905 million program that saw the replacement of around 450 miles of cast iron and unprotected steel gas pipelines over a three-year period. At the end of the pilot, PSE&G

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<sup>131</sup> South Jersey Industries. [SJI Announces Green Hydrogen Partnership with Atlantic Shores Offshore Wind](#). December 15, 2020.

<sup>132</sup> Environmental Defense Fund. [Collaboration with PSE&G](#).

<sup>133</sup> Environmental Defense Fund. [Utility Use of Advanced Leak Detection to Maximize Cost Effective Methane Reductions](#). April 10, 2019.

<sup>134</sup> New Jersey Clean Air Council. [Global Warming Pollutants in New Jersey: Beyond Carbon Dioxide](#). April 10, 2019.

<sup>135</sup> The New Jersey Greenhouse Gas Inventory does not report GHG emissions separately by type, but reports a total of 97.7 MMT CO<sub>2</sub>e. To isolate an estimate for methane emissions, LEI assumed 6% of statewide GHG emissions are attributable to methane (in line with this [New Jersey Clean Air Council report](#)). To estimate the proportion of methane emissions stemming from gas pipeline leaks, LEI multiplied this value further by 30%. (Source: New Jersey Department of Environmental Protection. [New Jersey Greenhouse Gas Inventory](#). February 2021).

<sup>136</sup> Assumes a conversion factor of 0.0053 metric tons CO<sub>2</sub>/therm. (Source: US EPA. [Greenhouse Gas Equivalencies Calculator – Calculations and References](#))

<sup>137</sup> New Jersey. [2019 New Jersey Energy Master Plan: Pathway to 2050](#). January 27, 2020.

“achieved an 83% reduction of methane emissions by replacing one-third fewer miles of gas lines than that needed to achieve the same result under a business as usual scenario.”<sup>138</sup>

Following the pilot program's success, PSE&G in January 2019 committed to modernizing a further 875 miles of gas pipelines over a five-year period through 2023.<sup>139</sup> PSE&G will utilize ALD “to estimate leak rates, targeting the leakiest sections for replacement first to achieve the greatest emissions reduction quickest”;<sup>140</sup> and

- **ETG:** ETG received approval in June 2019 for its Infrastructure Investment Program, a five-year, \$300 million investment plan which will utilize ALD technology to “map and measure otherwise invisible methane leaks using mobile sensors and advanced analytics to maximize environmental results on its system.”<sup>141</sup>

### 2.4.3.3 Quantifying the potential impact of NPAs in New Jersey

To get a sense of the extent to which non-pipe solutions could cover future capacity shortfalls in New Jersey, LEI quantified a rough range of estimates for the following NPAs:

- **voluntary demand response programs:** reductions in gas consumption on peak days resulting from potential GDC pilot programs;
- **direct load control:** reductions imposed by the utility in response to emergency conditions only;
- **renewable natural gas:** increases in gas supply on peak days from the development of a subset of New Jersey’s estimated RNG resource potential;
- **CNG or LNG trucking:** implementation of virtual pipelines to provide backup supply on peak days; and
- **advanced leak detection:** use of ALD technology to replace segments of leak-prone pipe and reduce LAUF gas.

LEI presents a hypothetical range of estimates (**low** versus **high**) for each NPA based on either conservative or more optimistic assumptions described in more detail below. In total, based on LEI’s assumptions, the four NPAs could fill a peak day capacity shortfall between 66 MDth/d (under the **low** assumptions) and 151 MDth/d (under the **high** assumptions) (see Figure 35). These reductions are independent of and in addition to savings from New Jersey’s energy efficiency programs covered in Section 2.3.6 (LEI’s scenario outlooks for firm demand).

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<sup>138</sup> Environmental Defense Fund. [Collaboration with PSE&G](#).

<sup>139</sup> Forbes. [How Your Local Gas Company is Adopting High-Tech Solutions to Get Methane Emissions Under Control](#). September 22, 2020.

<sup>140</sup> Colorado State University. [Plan to Map and Reduce Harmful Methane Emissions in New Jersey Made Possible by CSU Science](#). May 23, 2018.

<sup>141</sup> Environmental Defense Fund. [New Jersey Gas Utilities Embrace New Technology to Cut Greenhouse Emissions](#). August 7, 2019.

Figure 35. Hypothetical MDth/d impact of selected NPAs in New Jersey

Non-pipeline solution	MDth/d	
	Low	High
Voluntary demand response programs	30	61
RNG production	19	37
CNG or LNG trucking	17	53
Advanced leak detection technology	6.3	12.5
<b>Total</b>	<b>66</b>	<b>151</b>

#### 2.4.3.3.1 Voluntary DR program assumptions

Under the **high case** (i.e., more optimistic assumptions for uptake of voluntary DR), LEI estimates that voluntary DR programs could lead to annual gas savings of 61 MDth/d (see Figure 35). This assumes that potential GDC DR programs achieve the daily savings reported under SoCalGas' Smart Therm Program (discussed in Section 2.4.1.2) of 1.76%.<sup>142</sup> LEI applies this 1.76% daily savings rate to each GDC's average historical firm sendout for the five previous winter heating seasons, as reported in their respective BGSS filings.

Under the **low case** (i.e., more conservative assumptions), LEI assumes that only half of this peak reduction is achieved. This assumption recognizes that although the California experience is useful in informing potential DR program results in New Jersey, GDC programs will only apply to a subset of residential and C&I customers (e.g., initially only residential customers with smart thermostats), and thus will reduce only a subset of firm sendout.

#### 2.4.3.3.2 RNG production assumptions

Under the **high case**, LEI estimates that RNG production in New Jersey could provide 37 MDth/d of alternative fuel supply. This is based on state-level estimates published by the American Gas Foundation ("AGF") under a low resource potential (as discussed in Section 2.4.3.2.1).<sup>143</sup> We focus on a subset of AGF's RNG estimates under its low resource potential, namely the RNG produced via anaerobic digestion. This adjusts AGF's estimate (which is for 2040) to account only for the RNG potential that can be tapped into using technology that is readily implementable today.

Under the **low case**, LEI assumes that only half of this RNG production potential is achieved, because New Jersey RNG projects are currently at the early pilot and demonstration stages.

<sup>142</sup> Calculated as the average of the savings achieved for days when morning events were called (2.24%) and the savings achieved on days when evening events occurred (1.27%). (Source: Nexant. [2018-2019 Winter Load Impact Evaluation of SoCalGas Smart Therm Program](#). October 24, 2019.)

<sup>143</sup> American Gas Foundation. *Renewable Sources of Natural Gas: Supply and Emissions Reduction Assessment*. December 2019.



#### 2.4.3.3.3 CNG/LNG trucking assumptions

Under the **high case**, LEI estimates that CNG or LNG trucking could provide 53 MDth/d of additional gas supply. This assumes that GDCs can implement virtual pipelines with the same incremental capacity proposed by National Grid for its two CNG facilities in New York (see Section 2.4.2.3).<sup>144</sup> This requires the use of approximately 108 trucks per day. Although National Grid's experience is not a direct substitute for what GDCs may face if implementing CNG trucking in New Jersey, it serves as a useful proxy to quantify the potential impact.

Under the **low case**, LEI assumes that GDCs can implement CNG/LNG trucking at the capacity of National Grid's two CNG facilities during the 2019-2020 winter heating season, which required the use of some 42 trucks per day.

#### 2.4.3.3.4 ALD technology assumptions

LEI assumes LAUF gas is about 1% of firm sendout, or about 50 MDth/d; some of this is the result of leaks. Under the **high case**, LEI posits that ALD technology could reduce methane emissions from pipeline leaks by 25%. This is in line with assumptions from the Environmental Defense Fund, which estimated that "advanced leak detection methods would reduce more than 50% of methane emission by repairing only the largest 20% of leaks."<sup>145</sup> However, leaks have declined steadily over time for many years, and it is likely that most of the large leaks have already been repaired. LEI therefore assumes a high-end reduction of 12.5 MDth/d.

Under the **low case**, LEI assumes that only half of this reduction is achieved (i.e., a 6.25 MDth/d reduction). This conservative estimate accounts for potential uncertainties in the widespread deployment of ALD technology – for example, if not all GDCs implement the approach in their pipeline replacement programs, or if remaining leaks are small.

#### 2.4.3.3.5 Direct load control assumptions

Direct load control is intended to be used only in emergencies. If controllable thermostats were installed for all residential and commercial customers, they could be implemented quickly and be called upon at varying alert levels (e.g., for Orange and Red Alerts as discussed in more detail in Section 5).

In designing and implementing a direct load control program, it would make sense to start at a modest level and ramp up as demand on the system grows. A one-degree turnback would provide 76.6 MDth/d on a Winter Design Day if it occurred in 2020/21 (discussed in more detail in Section 5).

Equity issues could arise because not all customers are starting from the same place: some may have their thermostats typically set at 72 degrees, while others typically set their thermostats at

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<sup>144</sup> National Grid. [Natural Gas Long-Term Capacity Report](#). February 2020.

<sup>145</sup> Environmental Defense Fund. [Utility Use of Advanced Leak Detection to Maximize Cost Effective Methane Reductions](#). April 10, 2019.

68 degrees. An alternative for direct load control would be to set all thermostats at a turnback level that leaves everyone at 65 degrees, for example, no matter the level of the typical setting. However, without knowing where the average setting is, to begin with, it would be difficult to determine the setting required to achieve a given level of demand reduction. EIA reports that the most common residential thermostat setting is 67-69 degrees for the mid-Atlantic region, but though it is the most common range, it only accounts for 25% of respondents.<sup>146</sup>

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<sup>146</sup> EIA. Office of Energy Consumption and Efficiency Statistics, Forms EIA-457A and EIA-457C of the 2015 Residential Energy Consumption Survey.

### 3 Review of reports filed in the proceeding

Following the Order in Docket No. GO19070846 dated February 27, 2019 ("February 2019 Order"), the Board directed its Staff to initiate a stakeholder process to explore the issue of whether there is sufficient gas capacity secured to meet New Jersey customer needs.<sup>147</sup> The Board Staff sought answers to six questions and received responses from several entities, including New Jersey Natural Gas ("NJNG"). The NJNG filing, in turn, received a response from the Environmental Defense Fund ("EDF") and the New Jersey Conservation Fund ("NJCF"), together EDF/NJCF. In support of their respective comments, NJNG attached a report by Levitan and Associates ("Levitan Report"), and EDF/NJCF attached the affidavit of Greg Lander, President of Skipping Stone ("Skipping Stone Affidavit").

LEI reviewed the Levitan Report and Skipping Stone Affidavit; this section is an overview of the ways in which the analyses and findings presented in the reports do or do not align with the goals of the 2019 Energy Master Plan and Integrated Energy Plan.

#### 3.1 Key takeaways

##### 3.1.1 Levitan Report's underlying message does not necessarily follow from the analysis; Skipping Stone Affidavit assumed the problem away

The Levitan Report warns that New Jersey GDCs will be 127 MDth/d short of design day requirements by 2022/23. The Skipping Stone Affidavit argued the opposite – that a huge amount (over 1,000 MDth/d) of pipeline capacity is additionally available to New Jersey GDCs.

The key differences in the reports are:

- 1) **the way in which the Levitan Report and Skipping Stone Affidavit treated non-GDC pipeline capacity:** Levitan assumed gas pipeline capacity is available to NJ GDCs if it is under FT contract to the GDC or controlled by a producer/marketer with primary delivery points in New Jersey. It did not count any producer/marketer (referred to by Levitan as "third-party") capacity as available to the NJ GDCs if its primary delivery point is downstream of New Jersey. The Skipping Stone Affidavit argued that large volumes of non-NJ GDC capacity contracts which pass through New Jersey should be counted as available to the NJ GDCs, even if the primary delivery point is not in New Jersey.
- 2) **the Levitan Report addressed reliability, i.e., what happens during design day, capacity-constrained periods; the Skipping Stone Affidavit ignored what happens during capacity-constrained periods:** The Levitan Report referred to GDC design day firm demand and compared it to two categories of supply sources (pipeline and peaking capacity) available to meet the demand. The Skipping Stone Affidavit referred to historical peak demand, which for the GDCs is less than design day firm demand, but also included demand from other users such as power generators; and referred only to pipeline capacity as a source of supply. The purpose of LEI's analysis is to assess the reliability of firm

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<sup>147</sup> New Jersey BPU Staff. Notice: Docket No. GO19070846, "In the Matter of the Exploration of Gas Capacity and Related Issues." September 10, 2019. <[https://publicaccess.bpu.state.nj.us/CaseSummary.aspx?case\\_id=2108126](https://publicaccess.bpu.state.nj.us/CaseSummary.aspx?case_id=2108126)>

sources of gas supply to meet firm demand; the Skipping Stone Affidavit discussed neither design day demand nor sources of firm supply, so its conclusions do not shed light on reliability.

- 3) **the Levitan Report's demand outlook did not reflect the 2019 Energy Master Plan and Integrated Energy Plan; the Skipping Stone Affidavit argued for non-pipeline alternatives, which is consistent with State efficiency goals:** As discussed below, the Levitan Report did not examine the GDCs' design day demand assumptions – while the State's EMP and CEA are focused on impacting demand through efficiency targets and regulatory requirements for efficiency improvements for GDCs. Also, the Levitan Report's underlying message is that the only way to address a shortfall in firm supply is by expanding pipeline capacity; it did not consider any non-pipeline alternatives. The Skipping Stone Affidavit argued for non-pipeline alternatives, which is consistent with State efficiency goals. But as a reliability study, it missed the point on demand.
- 4) **Though they took different approaches, neither report examined demand thoroughly:** The Levitan Report took the GDCs' design day firm demand forecasts at face value. The Skipping Stone Affidavit did not address reliability, instead, it relied on historical peak day demand rather than design day firm demand in its analysis.

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.

**Figure 36. Levitan and Skipping Stone results (MDth/d)**

MDth/d	2018/19	2019/20	2020/21	2021/22	2022/23
<b>Levitan Report</b>					
GDC design day firm demand	5,009.4	5,035.6	5,079.4	5,122.8	5,204.6
Total firm supply*	<u>5,078.0</u>	<u>5,078.0</u>	<u>5,078.0</u>	<u>5,078.0</u>	<u>5,078.0</u>
Surplus (shortfall)	68.6	42.4	-1.4	-44.8	-126.6
6% adder	300.6	302.1	304.8	307.4	312.3
Shortfall including 6% adder	-232.0	-259.7	-306.2	-352.2	-447.6
<b>Skipping Stone Report</b>					
Historical peak total demand**	5,600.0				
Total pipeline supply***	<u>5,731.4</u>				
Surplus (shortfall)	131.4				
Total pipeline supply if all segmentation is used****	<u>7,054.9</u>				
Surplus if all segmentation is used	1,454.9				

Notes:

\* Levitan firm supply included GDC's FT on primary receipt points only (4,190 MDth/d), peaking resources such as LNG and CNG (535 MDth/d), and third-party capacity of 352.9 MDth/d. "Firm" includes both the gas itself (aka the commodity) and the transportation to deliver the gas to the end-user.

\*\* Skipping Stone did not provide the actual number, the 5,600 appears to be what is on the figure provided on page 6 of the Skipping Stone Affidavit. The historical number included all sectors using natural gas (not just GDC firm customers).

\*\*\* Based on Skipping Stone's addition of 1,431.398 MDth/d to Levitan's total firm capacity as described on page 5 of Skipping Stone Affidavit.

\*\*\*\* Based on analysis on page 5 of Skipping Stone Affidavit.

Source: Levitan & Associates, Inc. *Availability of Natural Gas Capacity to Meet New Jersey LDC Customer Needs*. Prepared for New Jersey Natural Gas. July 12, 2019. <[https://publicaccess.bpu.state.nj.us/CaseSummary.aspx?case\\_id=2108126](https://publicaccess.bpu.state.nj.us/CaseSummary.aspx?case_id=2108126)>; Lander, G. *BPU Docket No. GO19070846. Attachment to EDF/NJCF Comments. Expert Affidavit of Gregory M Lander. Exhibit GL-2*. October 2019 <[https://publicaccess.bpu.state.nj.us/CaseSummary.aspx?case\\_id=2108126](https://publicaccess.bpu.state.nj.us/CaseSummary.aspx?case_id=2108126)>.

### 3.1.2 LEI's conclusion and recommendations

The Levitan Report is focused on a problem (a shortfall of firm supply to meet firm demand) which has a number of potential solutions, but the subtext of the report is that there is only one solution: more pipeline capacity. The 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.

There is a more flexible and considered approach to the issue of ensuring reliability. In LEI's view, it makes sense to plan for the worst, but to carefully project the demand outlook and examine a variety of solutions which may fit the potential problem, as LEI discusses in this report.

- **Plan for the worst:** Assume that design day firm demand can occur and plan for it, not for historical peak firm demand.
  - Examine GDC design day firm demand outlooks critically and carefully and ensure the GDCs provide transparency in their demand models and assumptions.
- **Find solutions that fit the problem:** Supply risks of a large and unpredictable scale such as a loss of a compressor or cyber-attack could occur, but the costs versus benefits of adding a multi-million-dollar pipeline that must be paid for by a reservation rate 24/7/365 may not be a cost-effective way to insure against a one-off incident or accident.
  - Rather than an arbitrary adder (like the Levitan 6%) which may be too small to address a big crisis and too frequent for cost-effective design day planning, LEI recommends using a Shortfall Risk Assessment and Playbook for ensuring the system is prepared for and can address emergencies. Increasing forecasted demand with an adder is a blunt instrument, and if it implies more pipeline capacity is the only solution, it will be expensive as well as blunt.
  - Recognize that no amount of additional pipeline can make up for the loss of gas supply in systemic outages of natural gas-producing regions (such as the events in Texas in February 2021) or a cyber-attack on a pipeline. Other solutions are needed.

LEI outlines solutions that are consistent with New Jersey energy and climate policy, as well as reliability in Section 4 and Section 5.

## 3.2 Levitan Report

The Levitan Report utilized a reasonable approach, in that it based its assessment of firm demand from GDCs on design day firm demand (rather than historical peak demand); and in that it assumed that supply that could be used to meet that demand is the FT held by the NJ GDCs plus other delivery contracts with primary delivery points in New Jersey.

However, though reasonable, the Levitan Report applied the approach too conservatively because it excluded all producer/ marketer pipeline capacity with primary delivery points in New York or New England.

### 3.2.1 Levitan sees a gas capacity shortage

Levitan's key assumptions were:

- **The GDCs' demand outlooks were taken at face value.** Levitan relied on the design day firm demand outlooks filed in BGSS 2018, without examining the drivers; and
- **GDCs cannot expect to have access to any transportation capacity which is under contract with primary delivery points outside of New Jersey.** Levitan assumed that zero capacity with downstream delivery points (e.g., in New York and New England) would be available to New Jersey customers on a design day.

Based on these assumptions, Levitan projected a capacity shortfall of 126.6 MDth/d by 2022/23, excluding the 6% adder.

### 3.2.2 Levitan did not examine the drivers of firm demand

In its analysis, Levitan took the design day firm demand forecasts provided by the GDCs in their BGSS filings as given.<sup>148</sup> In a subsequent filing in the docket, Levitan noted that it “*did not conduct any analysis on the demand side. Instead, [we] assumed the BGSS design day demand forecasts as filed in 2018 as an input.*”<sup>149</sup> Levitan’s demand outlook only went to 2023, and while Levitan indicated that each GDC “*offers and promotes energy efficiency and conservation programs,*” it did not indicate the extent to which these factors may impact the aggregated outlooks.<sup>150</sup>

LEI examined and updated Levitan’s demand assumptions, using the GDCs’ BGSS filings for 2020. LEI confirmed that the outlooks used by Levitan, though dated 2018, are not much different than the most recent outlooks filed by the GDCs (see Figure 37). LEI also confirmed that the 2018 design day firm demand outlooks used by Levitan did not include any gas reserves to cover LOLP (if they had, a 6% adder would have been redundant).

LEI’s scenario outlooks do not differ much from Levitan’s BGSS-based outlooks in the near term; but over time, ignoring the impacts of energy efficiency leads to higher demand outlooks and, therefore, larger and larger shortfalls that would appear to need addressing.

**Figure 37. GDC design day firm demand outlooks (MDth/d)**

	2020/21	2021/22	2022/23	2023/24
<b>Levitan, based on June 2018 BGSS</b>				
ETG	598	603	608	
NJNG	942	954	965	
PSE&G	2,959	2,979	3,034	
SJG	581	588	597	
<b>Total</b>	<b>5,079</b>	<b>5,123</b>	<b>5,205</b>	
<b>June 2020 BGSS</b>				
ETG	598	605	611	618
NJNG	934	945	955	964
PSE&G	2,981	2,997	3,037	3,060
SJG	579	588	597	607
<b>Total</b>	<b>5,092</b>	<b>5,135</b>	<b>5,200</b>	<b>5,249</b>
<b>LEI scenarios</b>				
2a Historical trend	5,092	5,140	5,189	5,238
2b Historical trend and GDCs meet Board targets	5,092	5,125	5,162	5,200

<sup>148</sup> Levitan indicates that its demand outlook/assumptions are based on design day BGSS filings for June 1, 2018 for the four New Jersey LDCs. However, one of the sources cited in Levitan footnote 1, page 1, for NJNG does not contain NJNG’s design day outlook, nor any reference to workpapers or exhibits which might contain this outlook.

<sup>149</sup> Levitan & Associates. *Docket No. Go19070846. In The Matter Of The Exploration Of Gas Capacity And Related Issues. Levitan Comments.* October 22, 2019.

<sup>150</sup> Levitan & Associates, Inc. *Availability of Natural Gas Capacity to Meet New Jersey LDC Customer Needs.* Prepared for New Jersey Natural Gas. July 12, 2019. P.17

In Section 2.3.3 previously, LEI noted that the GDC firm demand outlooks do not necessarily incorporate all energy efficiency impacts going forward, and they assume a faster rate of underlying demand growth than in the past. Because of this, LEI recommends Scenario 2a or Scenario 2b as a baseline outlook. This results in a slightly lower near-term need for gas to meet design day firm demand. To address incidents and accidents, LEI recommends, rather than an arbitrary adder of 6%, that the BPU employ best practices (Section 5).

### **3.2.2.1 Levitan discussion of Station 210 construes supply availability very narrowly**

The Levitan Report includes a brief discussion of Transco Station 210 pooling point contracts. It noted that New Jersey GDCs have contracts for 285 MDth/d out of Station 210.<sup>151</sup> It noted that a portion of the total 339.7 MDth/d of contracts into Station 210 (48.2 MDth/d) are held by the NJ GDCs; and an additional 252.1 MDth/d is held by producer/marketers. Levitan argued that to access producer/marketer capacity, the NJ GDCs must compete with other shippers, implying that the capacity would not be available to the NJ GDCs. LEI disagrees with this conclusion. Yes, buyers must compete with one another, and yes, the prices could be high, but the supply is not unavailable. GDCs, whether in New Jersey or downstream, are potential buyers of this supply on peak days.

### **3.2.2.2 Levitan's discussion of non-GDC supplies mixed apples and oranges**

The Levitan Report noted that there is 646 MDth/d from producer/marketers that the NJ GDCs include as a supply resource deliverable to city gates.<sup>152</sup> The GDCs include capacity provided by producer/marketers in their resource outlooks, referring to this as "off system peaking resources." The 646 MDth/d includes contracts entered into by the GDCs and contracts by customers that rely on retail TPSs. The Levitan Report compared the 646 MDth/d to a 412 MDth/d of primary firm delivery capacity owned by producer/marketers and argued that amounts to a shortfall. But Levitan mixed apples and oranges with this comparison. The 646 MDth/d includes non-firm customers relying on TPSs, as well as firm customers of the GDCs. The non-firm (i.e., interruptible) customers of TPSs, by definition, do not need to have firm delivery contracts underpinning the services they use.

### **3.2.3 Planning for supply disruptions should recognize their unpredictable size**

Levitan argued that there is an overreliance on two pipelines that brings with it a risk of disruption in the event of a significant outage or other pipeline contingency. This may be true, and such a disruption could be huge, larger than the 6% adder that Levitan arbitrarily added to design day firm demand. Such an adder is both too little and too much. It is too little to cope with a real disruption, which could reach over 900 MDth/d if a large compressor went off-line on Transco, for example. It is also too much: Adding 300 MDth/d every single year of the outlook implies that it would happen every year, on a design day, and thus justify investment in permanent new infrastructure.

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<sup>151</sup> Levitan Report. P. 8.

<sup>152</sup> Levitan Report. P. 18.



For coping with one-off supply emergencies, LEI recommends instead implementing a Playbook based on best practices (see Section 5).

### **3.3 Skipping Stone Affidavit**

In its comments to the BPU, referred to as “Comment of Environmental Defense Fund and New Jersey Conservation Foundation on Docket No. GO19070846, In the Matter of the Exploration of Gas Capacity and Related Issues,” EDF and NJCF present comments and analysis by Skipping Stone that counter the results of the Levitan Report.

The Skipping Stone Affidavit took a market perspective, rather than a reliability perspective, in its analysis. In other words, it did not examine the ways in which firm gas demand on a design day can be met. Instead, it referred to historical peak demand from GDCs (which is less than design day demand by GDCs) as well as all other types of customers, including electric generating plants. It focused on the flexibility of supply options during times in which the system is not constrained, rather than examining supply options during times, such as design days, when the system is constrained.

The Skipping Stone Affidavit contends the following:

- **Over 300 MDth/d of capacity related to the NJ-NY Extension on Tetco that was not included by Levitan is available to New Jersey GDCs:** Skipping Stone pointed out the ConEd Manhattan delivery point with a capacity of 800 MDth/d exists on the Tetco pipeline as a receipt point, which has been contracted by Consolidated Edison of New York (“ConEd”), and producer/marketers. Skipping Stone argued that the maximum capacity that has ever been delivered on the Manhattan delivery point for receipt was 465 MDth/d. In that case, the remaining 334 MDth/d cannot be taken by ConEd and could be used by New Jersey GDCs. Skipping Stone argued the 334 MDth/d should be included as a potential source of gas transmission capacity to New Jersey GDCs.
- **Additional capacity is available on interconnections to downstream pipelines:** Skipping Stone provided analysis that suggested that the Algonquin pipeline has more capacity coming in than firm takeaway capacity, resulting in a possible additional 361 MDth/d that can be used by New Jersey GDCs.
- **Capacity into Station 210 should include capacity proceeding to other delivery points:** By including downstream delivery points southbound and northbound, respectively, from New Jersey, whose paths include Station 210, an additional 1,792 MDth/d and 133 MDth/d would be added.

These add up to a total of about 2,500 MDth/d over the Levitan estimate of FT on pipelines, according to Skipping Stone.

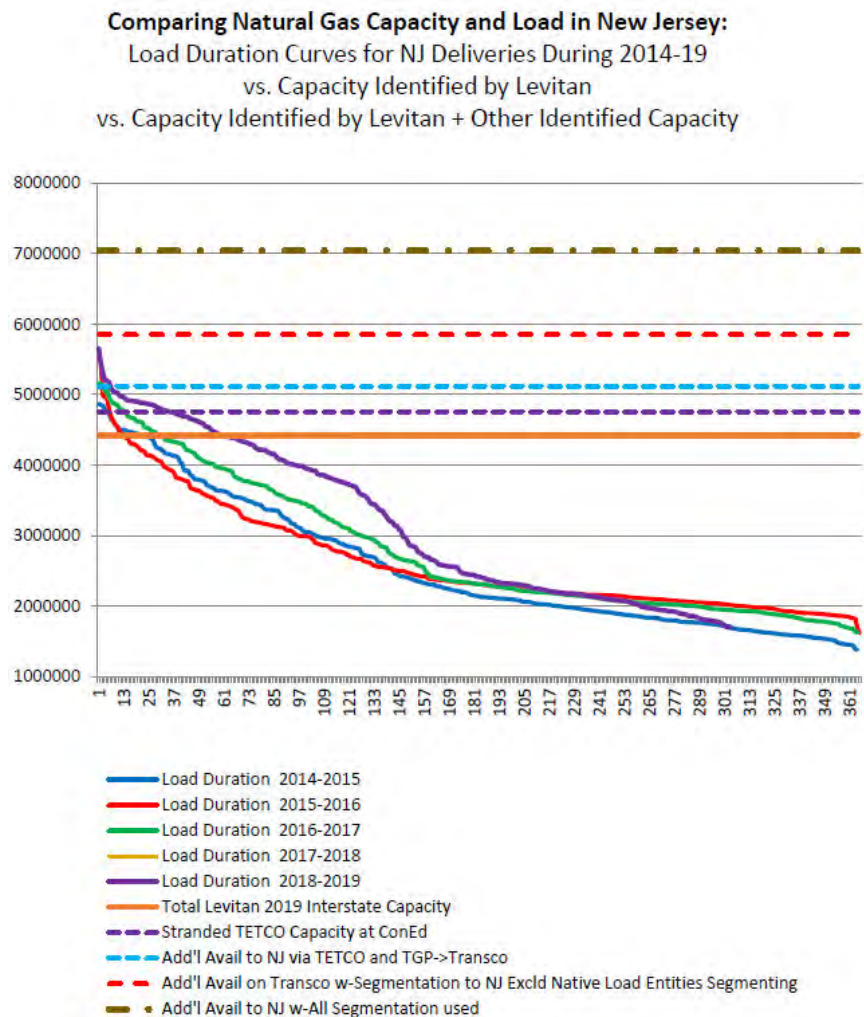
#### **3.3.1 Skipping Stone missed the point for demand**

The Skipping Stone Affidavit referred to a load duration curve for total New Jersey gas demand between 2014 and 2019 (see Figure 38. Skipping Stone gas demand load duration and capacity comparison\* ). This comparison makes it appear as if there is a large amount of idle capacity – which, under normal conditions, there may well be. But GDCs are required to plan for design

day firm demand, not historical peak demand (which includes interruptible as well as firm customers). By definition, because historical peaks in firm demand are generally much lower than design day firm demand, comparing an actual historical load duration curve with total pipeline capacity will make it appear that there is a large amount of unused capacity. The problem is that much of that capacity would not be available on a design day, as cold weather in the northeast would likely impact all GDCs in New Jersey as well as in New York and New England, as it did during the Polar Vortex.

LEI does not necessarily agree with the design day firm demand outlooks provided by each of the GDCs, but we agree that it is design day firm demand (not historical peak demand) that needs to be carefully examined to determine reliability, i.e., to establish whether and to what extent a future shortfall will occur. Skipping Stone missed the point on the demand side.

**Figure 38. Skipping Stone gas demand load duration and capacity comparison\***



Source: Lander, G. BPU Docket No. GO19070846. Attachment to EDF/NJCF Comments. Expert Affidavit of Gregory M Lander. Exhibit GL-2. October 2019.

\*Horizontal axis is the number of days in a year, in order of highest demand day to lowest demand day.

### 3.3.2 Ambiguity over the ConEd Manhattan delivery point

The Skipping Stone Affidavit referred to 800 MDth/d on Tetco that is deliverable to the ConEd Manhattan delivery point, noting that ConEd has contracted for 170 MDth/d, and producer/marketers have contracted for the rest.<sup>153</sup> The Levitan Report concurred with this, noting that 630 MDth/d is held by “prominent producers in the Marcellus who enter into asset management agreements with marketers...”<sup>154</sup> LEI verified that Chesapeake Energy holds 425.25 MDth/day and Statoil Nat Gas (Equinor) holds 204.75 MDth/d.<sup>155</sup> The most gas delivered to the ConEd Manhattan receipt point was 465 MDth/d (on December 14, 2017 – though a new high could be reached in the future), which led Skipping Stone to argue that the remainder, 335 MDth/d is available for use in New Jersey (the Tetco NJ-NY Extension runs through several cities in New Jersey, with delivery points). In contrast, the Levitan Report assumed none is available to any NJ GDCs.

LEI does not disagree with Skipping Stone that New Jersey customers could use at least some of the unused capacity, but on a design day, it is unlikely that all of it would be available. Rather than make assumptions about the volume of such capacity that would be available, LEI’s supply estimates in Section 4 rely on data from the GDCs, which specifically provide the total volume of peaking capacity for which they have contracted for by 2024/25, and LEI assumes this value is constant through 2030.<sup>156</sup>

### 3.3.3 Ambiguity over Algonquin available capacity

According to Enbridge, the owner of the Algonquin pipeline, its peak day capacity is 3,120 MDth/d.<sup>157</sup> LEI’s examination of the current contracts on Algonquin shows that delivery to points associated with gas distribution companies and other end-users totals 3,080 MDth/d (see Figure 39). This is very close to the 3,120 MDth/d total capacity claimed by Enbridge, indicating that there would not be much capacity to spare if the GDCs and end-users need all their contracted volumes, as they would on a design day.

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<sup>153</sup> Skipping Stone. p. 3.

<sup>154</sup> Levitan Report. p. 23.

<sup>155</sup> Federal Energy Regulatory Commission. 139 FERC ¶ 61,138 Order Issuing Certificates and Approving Abandonment. May 21, 2012. Docket No. CP11-56-000.

<sup>156</sup> For NJNG, LEI assumes that NJNG will contract for 200 MDth/d going forward, based on its past contracting practice.

<sup>157</sup> Enbridge.

<[https://www.enbridge.com/~media/Enb/Documents/Factsheets/FS\\_EnergyInfrastructureAssets.pdf?la=en](https://www.enbridge.com/~media/Enb/Documents/Factsheets/FS_EnergyInfrastructureAssets.pdf?la=en)>

**Figure 39. Contracts for delivery and receipt on Algonquin, Dth/d (as of April 1, 2021)**

Delivery	
Delivery to non-NJ GDCs & end-users	3,046,887
Delivery to NJ GDCs	33,000
<b>Total delivery contracts</b>	<b>3,079,887</b>
Receipt	
Receipt on points in NJ+NY	2,138,943
Receipt on points in CT, MA, RI (except LNG)	1,643,157
<b>Total receipt contracts except LNG</b>	<b>3,782,100</b>

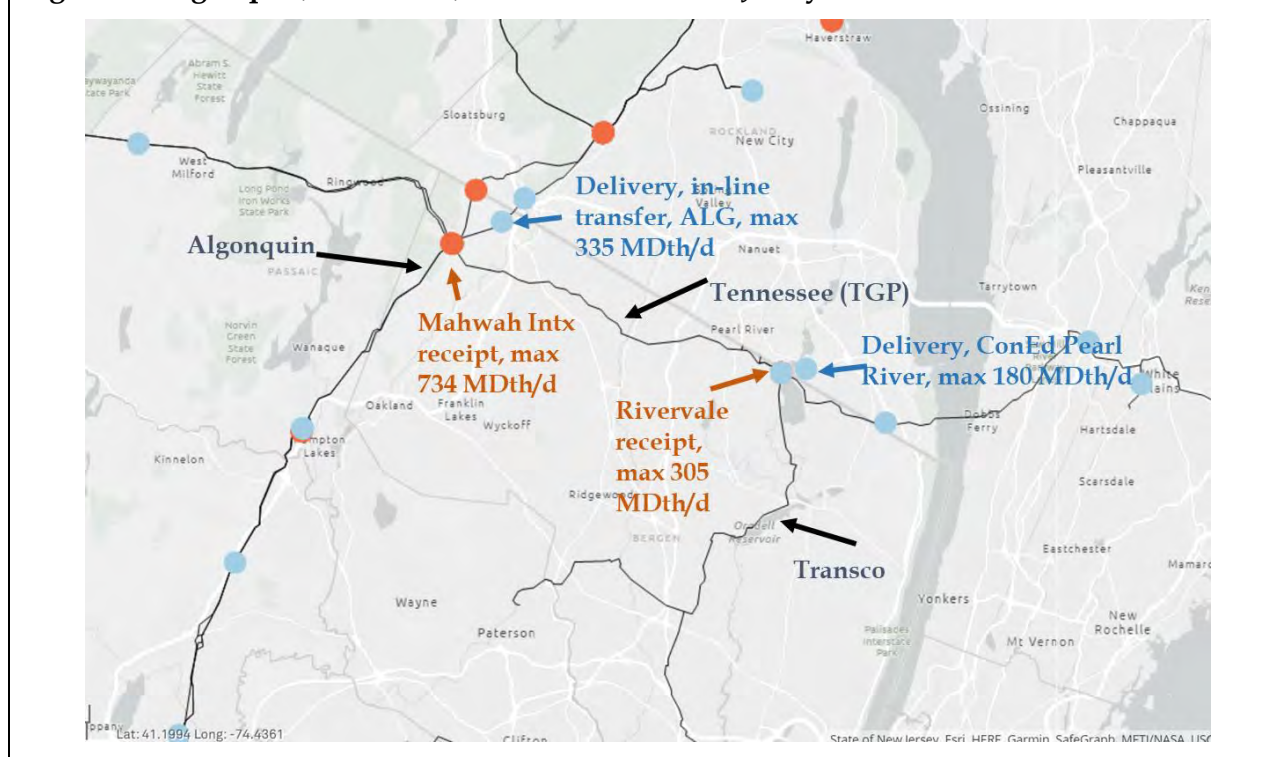
Source: Third-party data provider.

Skipping Stone argued that excess capacity of 360.8 MDth/d of exists on Algonquin, is readily accessible on Tennessee Gas Pipeline (“TGP”), and passes locations where Transco can receive gas from TGP for delivery in New Jersey. Skipping Stone was not specific, but the report seemed to be referring to capacity at the Mahwah interconnection point where gas from TGP is delivered to Algonquin (see Figure 40). Downstream of this, the Algonquin meter station has a maximum capacity of 335 MDth/d; and the Transco Rivervale receipt point has a capacity of 305 MDth/d at its interconnection with TGP. This may be the basis of Skipping Stone’s claim of excess capacity on Algonquin in New Jersey. However, the Rivervale receipt point is on the New York border, and points downstream on TGP (in New York) are contracted for, including ConEd’s TGP/Pearl River delivery point with a maximum of 180 MDth/d. On any given day, the scheduled quantities at Rivervale are well over 200 Dth/d. Rather than make assumptions about the volume of capacity which might be available at this delivery point, LEI’s supply estimates in Section 4 rely on data from the GDCs, which provide the total volume of peaking capacity for which they have contracted for by 2024/25, and LEI assumes this value is constant through 2030.<sup>158</sup>

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<sup>158</sup> For NJNG, LEI assumes that NJNG will contract for 200 MDth/d going forward, based on its past contracting practice.

Figure 40. Algonquin, Tennessee, and Transco in New Jersey



### 3.3.4 Station 210 offers flexibility but not additional supply on constrained days

The Skipping Stone Affidavit argued that, including secondary delivery points, there is another 1,792 MDth/d of capacity through Station 210 going south; and another 133.5 Dth/d going north. Skipping Stone seems to imply by this that there is much more capacity available to the NJ GDCs.

Skipping Stone’s argument is based on the practice of segmentation, which creates flexible receipt and delivery points along a gas transportation path, allowing shippers to upload and unload capacity. At pipeline interconnections, extra gas might be offered and can be handed off, or even be left at the interconnection point, and another potential buyer can pay for it and move it along through the system. The quantity of capacity dropped at one point cannot be exceeded by the quantity that can be picked up downstream on the path.

Segmentation thus increases the financial flexibility (and therefore improves economic efficiency and potentially reduces costs) of the gas transport system. It helps get around the inflexible receipt and delivery points specified in shippers’ transportation contracts. In a sense, then, it can be considered a third source of supply (in addition to gas sourced from producing regions and gas sourced from traded hubs in a market zone). On a normal day (not a design day or otherwise-constrained day), there is usually some idle transportation capacity that can be better utilized by the flexibility offered by segmentation. But segmentation does not create additional new physical capacity.

On a constrained day, such as a design day, when pipeline capacity and gas are in short supply and all FT contracts are in use, there is little to no spare capacity to be optimized via segmentation.

The capacity across Station 210 would be in high demand during a design day because cold weather would affect all gas users in the region, not just in New Jersey. Holders of FT would use all their contracted capacity and go to the market to buy bundled gas from producer/marketers (off-system peaking capacity). Segmentation gives buyers and sellers of gas more flexibility, but not more total capacity; it addresses economic efficiency, but not reliability. Rather than make assumptions about the volume of capacity during peak times which might be available as a result of segmentation, LEI's supply estimates in Section 4 rely on data from the GDCs, which provide the total volume of peaking capacity for which they have contracted.

## 4 Shortfall Risk Assessment for 2021-2030

### 4.1 Key takeaways

Using the gas demand outlooks and firm supply data developed and compiled in previous sections, LEI assessed the risk to New Jersey customers of a gas supply shortfall occurring over the 2021-2030 period. To account for the uncertainty inherent in a forward-looking exercise, LEI estimated this shortfall risk under five conditions: (1) a **Normal Winter Day**; (2) a **Historical Peak Day**; (3) a **Winter Design Day** (based on design day criteria from the GDCs as a whole); (4) a **1-in-90 Design Day** (assuming all the GDCs design for a 1-in-90 winter day); and (5) a **Perfect Storm** of high demand and a large supply disruption.

The key takeaways from this analysis are:

- **High probability outcomes:** By 2030, New Jersey firm gas customers are not likely to experience a shortfall in gas supply on a **Normal Winter Day**, or even on a colder-than-normal winter day (i.e., weather similar to historical cold-weather events or a **Historical Peak Day**). There would be a surplus gas capacity of 3,196 MDth/d in a normal winter.

Figure 41. Shortfall Risk Assessment

Conditions (2029/30)	Total firm demand (MDth/d)	Surplus or shortfall (MDth/d)
<b>High probability, low impact</b>		
Normal Winter Day	2,547	3,196
Historical Peak Day	3,967	1,776
<b>Low probability, moderate impact</b>		
Winter Design Day	5,469	274
<b>Lower probability, higher impacts</b>		
1-in-90 Design Day	5,896	-153
Perfect Storm (2026/27)	5,321	-525

- **Low probability outcome, with moderate impact:** New Jersey firm gas customers, are not likely to experience a shortfall in gas supply by 2030, even on a **Winter Design Day**. A Winter Design Day is a planning condition with firm demand typically about 35% higher than historical peak demand. Assuming LEI’s Scenario 2b (with 0.80% annual growth in gas demand), LEI estimates there would be 274 MDth/d to spare by 2030. This scenario assumes that no progress is made on building electrification efforts over the next decade;
- **Lower probability outcome with potentially high impact:** A **1-in 90 Design Day**, and assuming a rate of growth from LEI’s Scenario 2b (0.80% per year), a supply shortage of 153 MDth/d could occur by 2030. This is large enough to be classified as an Orange-level emergency as defined in LEI’s Playbook (Section 5). LEI views this as a predictable

shortfall and addresses ways to fill the gap using a portfolio of NPAs, as discussed below. 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;

- **Lower probability outcome with potentially very high impact:** A pipeline outage that occurs during a Winter Design Day and is assumed to impact half the capacity on Transco, is characterized by LEI as a **Perfect Storm**. This could lead to a large shortfall of 525 MDth/d. LEI categorizes this as a Red-level emergency and discusses strategies to cope with this in the Playbook (Section 5).

## 4.2 How LEI developed the firm demand conditions for 2030

To assess the risk of a shortfall in firm natural gas capacity out to 2030, LEI developed five demand conditions to reflect a range of potential outcomes. Each of the conditions is defined based on actual demand experienced by the GDCs (normal winter day, historical peak day); or on design day projections provided by the GDCs. Each condition, therefore, includes all firm customers, including retail choice customers.

1. **Normal Winter Day:** demand from firm New Jersey customers on a normal winter day (i.e., not a peak or extreme weather day), which LEI defines as the average winter temperature recorded at the Newark, New Jersey station for the latest three-decade period (1981-2010) available from the US National Oceanic and Atmospheric Administration (“NOAA”) database. This equates to a temperature of 34.2 degrees Fahrenheit, or 30.8 HDD.<sup>159</sup>

To estimate the implied firm demand on a normal winter day for the 2021-2030 period, LEI calculated the average peak day demand per HDD recorded by GDCs for the past five years (2016-2020) and multiplied this by 30.8. LEI then escalated this implied firm demand by 0.95% per year through 2030, in line with the GDCs’ observed weather-normalized annual growth rate, discussed previously in Section 2.3.

2. **Historical Peak Day:** peak demand from firm New Jersey customers through 2030 if demand were to grow at the observed historical pace of 0.95% annually. For reference, compared to a normal winter day of 30.8 HDD, peak winter days over the past five years averaged around 48.0 HDD (according to the 2016-2020 BGSS filings by GDCs).

To estimate the implied firm peak demand out to 2030, LEI calculated the average firm sendout across all four GDCs on historical peak days from the past five years, and escalated this by 0.95% per year;

3. **Winter Design Day:** peak demand from firm New Jersey customers on a design day – i.e., the coldest day of the year, which sets the basis for gas system planning. Generally, New Jersey GDCs plan for a design day using on average 66.4 HDD.

This condition matches Scenario 2b presented in Section 2.3.6, which assumes that New Jersey stays on the underlying weather-normalized historical trend of 0.95% per year, but

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<sup>159</sup> NOAA. [Data Tools: 1981-2010 Normals: Annual/Seasonal Normals.](#)



that GDCs will meet Board ordered energy efficiency reduction targets in line with the State’s Clean Energy Act of 2018, so that net firm demand growth is 0.80% per year;

4. **1-in-90 Design Day:** peak demand from firm New Jersey customers on a 1-in-90-year design day, which LEI assumes is equivalent to 71.3 HDD. This is the maximum or most extreme design day standard used by US gas utilities and is currently only utilized by NJNG of all the New Jersey GDCs.

To estimate the implied firm demand for the 2021-2030 period, LEI used the average peak day demand per HDD recorded by GDCs for the past five years and multiplied this by 71.3. LEI then escalated this by 0.95% per year; and

5. **Perfect Storm:** peak demand from firm New Jersey customers on a design day (i.e., Winter Design Day conditions) combined with a major supply disruption, which could be the result, for example, of technical malfunctions or a cyber-attack. This supply disruption assumes that New Jersey GDCs lose half of their supply on the Transco pipeline. LEI assumes this happens in 2026/27 for illustrative purposes.

Figure 42 summarizes these conditions, including the calculated firm demand for 2020/21 and 2029/30 in MDth/d, the assumed annual growth rates over the 2021-2030 period, as well as the implied HDD. As seen in the table, LEI projects firm demand to reach 2,547 MDth/d under the Normal Winter Day (the lowest demand) condition and 5,896 MDth/d under the 1-in-90 Design Day (the highest demand) condition by 2029/30 (see Figure 43).

**Figure 42. The five conditions and underlying assumptions**

#	Condition	Firm demand (MDth/d)		CAGR	Average HDD
		2020/2021	2029/2030		
1	Normal Winter Day	2,339	2,547	0.95%	30.8
2	Historical Peak Day	3,644	3,967	0.95%	48.0
3	Winter Design Day	5,092	5,469	0.80%	66.4 *
4	1-in-90 Design Day	5,415	5,896	0.95%	71.3
5	Perfect Storm	5,092	5,469	0.80%	66.4 *

\* Averages HDD assumptions for ETG, NJNG, and SJG. PSE&G does not specify the HDD standard it uses in its BGSS filings, and as such, has been excluded from the average.

Although 1-in-90 Design Day and Perfect Storm conditions reflect extreme, low-likelihood events, they both provide useful starting points for planning. The 1-in-90 Design Day scenario deals with a shortfall due to an extreme weather event. Perfect Storm deals with a shortfall due to a major system supply disruption or outage, which coincides with high demand, so Perfect Storm uses the same demand outlook as Winter Design Day.

Figure 43. LEI's projected firm demand by condition and year

		Firm demand (MDth/d)									
Demand condition		2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30
[a]	Normal Winter Day	2,339	2,361	2,384	2,406	2,429	2,452	2,476	2,499	2,523	2,547
[b]	Historical Peak Day	3,644	3,678	3,713	3,749	3,784	3,820	3,856	3,893	3,930	3,967
[c]	Winter Design Day	5,092	5,125	5,162	5,200	5,232	5,272	5,321	5,370	5,419	5,469
[d]	1-in-90 Design Day	5,415	5,466	5,518	5,571	5,624	5,677	5,731	5,785	5,840	5,896
[e]	Perfect Storm	5,092	5,125	5,162	5,200	5,232	5,272	5,321	5,370	5,419	5,469

LEI's shortfall analysis focuses on meeting only firm demand, **not** total demand, which includes demand from interruptible customers and any firm TPS customers not included in GDC forecasts of firm demand. Under extreme weather and outage events, everyone on the system (including interruptible customers) would be affected.

### 4.3 Estimated ranges of firm supply shortfall under the five conditions

Using the five demand conditions, LEI calculated the potential shortfalls for 2021-2030 by comparing projected demand to the following sources of firm capacity:

- **FT on interstate pipelines, and storage:** As discussed previously in Section 3.2, GDCs hold arrangements for FT, storage, and LNG contracts on the five interstate pipelines into New Jersey (Algonquin, Columbia, Tennessee, Tetco, and Transco). The total for this capacity was reported by the GDCs in their BGSS filings at 3,930 MDth/d for 2020/21, increasing to 4,035 MDth/d by 2024/25; LEI assumed these contracts remain in place through the end of the forecast period (2029/30) (see Figure 44).

Under the Perfect Storm condition, LEI assumes a major supply outage occurs on the Transco pipeline, taking out half of its FT capacity into New Jersey. This reduces total FT capacity to 3,087 MDth/d. LEI assumes this outage occurs in 2026/2027 (for illustrative purposes), and is resolved by the following winter heating season;

- **peaking supply from on-system resources:** GDCs own and operate LNG and LPA peaking facilities with a total maximum daily sendout capability of 533 MDth/d. LEI assumes these resources are maintained at their current capabilities throughout the forecast period;
- **off-system resources:** As noted previously, rather than make specific assumptions as to the availability of off-system peaking supplies related to ConEd Manhattan, Rivervale, or any other delivery point, LEI based its projection of off-system resources on the GDCs' own outlooks for such resources. Off-system peaking resources projected by NJNG decline from 230.7 MDth/d in 2020/21 to 80.0 MDth/d in 2021/22, and to zero thereafter. However, this decline is the result of the short-term nature of the contracts, which need to be renewed or replaced annually.<sup>160</sup> LEI assumes that NJNG will contract for 200 MDth/d going forward, based on its past contracting practice. The other GDCs projected non-zero

<sup>160</sup> NJNG. *In The Matter of The Petition of New Jersey Natural Gas Company for the Annual Review and Revision of its Basic Gas Supply Service (BBGSS) and Conservation Incentive Program (CIP) Rates For F/Y 2021 "Workpaper 7"* May 29, 2020. Docket #GR20060378Workpaper #7.

off-system resources through 2024/25, and LEI used those projections directly. For 2025/26 and later, LEI projected total off-system peaking resources at a constant 619 MDth/d (see Figure 44); and

- **TPS:** The GDCs project supplies from third-party suppliers serving retail choice customers to increase somewhat, from 546 MDth/d in 2020/21 to 557 MDth/d by 2024/25. LEI assumed a constant 557 MDth/day through 2030, reflecting the lack of growth in the trend of retail choice shown previously in Figure 14. The GDCs include retail choice customers in the GDC design day demand outlooks; LEI includes these as well for consistency.

LEI's projections of total supply to meet firm load are 5,743 MDth/d in 2030. In the Perfect Storm condition, we assume a supply disruption occurs once in the outlook, in 2026/27, at which point we project a loss of about 50% of Transco capacity, i.e., 948 MDth/d (see Figure 44).

**Figure 44. Projected components of supply**

Supply component	Supply (MDth/d)									
	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30
Pipeline and storage FT	3,930	3,980	4,035	4,035	4,035	4,035	3,087	4,035	4,035	4,035
On-system peaking resources	533	533	533	533	533	533	533	533	533	533
Off-system peaking resources	656	644	596	602	619	619	619	619	619	619
TPS	546	547	554	556	557	557	557	557	557	557
[f] <b>Total</b>	<b>5,665</b>	<b>5,704</b>	<b>5,717</b>	<b>5,726</b>	<b>5,743</b>	<b>5,743</b>	<b>5,743</b>	<b>5,743</b>	<b>5,743</b>	<b>5,743</b>
[g] <b>Total under Perfect Storm*</b>	<b>5,665</b>	<b>5,704</b>	<b>5,717</b>	<b>5,726</b>	<b>5,743</b>	<b>5,743</b>	<b>4,795</b>	<b>5,743</b>	<b>5,743</b>	<b>5,743</b>

\* Perfect Storm assumes a major compressor station outage disables half of the FT capacity into New Jersey on the Transco pipeline.

Sources for 2020/21 to 2024/25:

ETG. *In the Matter of the Petition of Elizabethtown Gas Company to Review its Periodic Basic Gas Supply Service Rate: Case Summary, Petition, Testimony, and Schedules.* Schedule LJW-16 June 1, 2020; and Response to data request DR 2.1, 2.2, 2.3 BPU Docket No. GR20010033. June 9, 2021.

NJNG. *In The Matter of The Petition of New Jersey Natural Gas Company for the Annual Review and Revision of its Basic Gas Supply Service (BBGSS) and Conservation Incentive Program (CIP) Rates For F/Y 2021 "Workpaper 7"* May 29, 2020. Docket #GR20060378; and Response to data request 2.1, BPU Docket No. GO20010033. June 9, 2021.

PSE&G. *In the Matter of Public Service Electric and Gas Company's 2020/2021 Annual BGSS Commodity Charge Filing for its Residential Gas Customers under its Periodic Pricing Mechanism and for Changes in its Balancing Charge.* Item 16. June 1, 2020; and Response to data requests BPU Docket No. GO2001003. June 7, 2021.

SJG: *In the Matter of the Board's Order Regarding Natural Gas Supply Estimates and New Customers.* Docket Nos 748-639, 774-363 and GE900706585, *Five Year Forecast of Requirements and Capacity Entitlements November 2019 through October 2024.* Attachment TWR-6, November 30, 2020; and Response to data requests BPU Docket No. GO20010033. June 9, 2021.

The supplies that LEI included in Figure 44 above are more abundant than assumed by the Levitan Report. Levitan assumed 5,205 MDth/d by 2022/23, while LEI shows 5,717 MDth/d. Rather than automatically excluding any supply from producer/marketers that does not have primary delivery points in New Jersey (as Levitan did), LEI implicitly included some of this supply, in that it probably makes up a portion of the off-system peaking resources reported by the GDCs. The 5,717 MDth/d is lower than the 7,054.9 MDth/d assumed by Skipping Stone because segmentation generally, and spare capacity, which may exist at Rivervale and/or ConEd Manhattan, are not sources of reliable supply on peak days.

The supply included in Figure 44 does not include the 405 MDth/d capacity contracted by the GDCs under precedent agreements on the PennEast Pipeline, and none of the GDCs included it in their supply resources.

The potential firm supply surplus (highlighted in green or yellow) or shortfall (highlighted in orange) under each of the five conditions is shown in Figure 45. For example, on a Normal Winter Day, firm demand line [a] in Figure 34 above is subtracted from line [f] in Figure 44 above to arrive at a substantial 3,196 MDth/d surplus in 2030.

**Figure 45. Projected surplus or shortfall in each demand condition**

Firm supply balance	Potential surplus/shortfall (MDth/d)									
	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30
[f] - [a] Normal Winter Day	3,326	3,342	3,334	3,320	3,314	3,291	3,268	3,244	3,220	3,196
[f] - [b] Historical Peak Day	2,021	2,025	2,004	1,977	1,959	1,923	1,887	1,850	1,813	1,776
[f] - [c] Winter Design Day	573	578	555	526	512	471	423	374	324	274
[f] - [d] 1-in-90 Design Day	250	237	199	155	120	66	12	(42)	(97)	(153)
[g] - [e] Perfect Storm	573	578	555	526	512	471	(525)	374	324	274

This analysis shows that sufficient firm capacity exists to meet firm demand from customers in New Jersey under a Normal Winter Day, a Historical Peak Day, and even on a Winter Design Day.

However, the risk of a potential shortfall exists for up to 153 MDth/d in a 1-in-90 Design Day by 2030, and 525 MDth/d in 2026/2027 (i.e., the year in which the Transco outage is modeled to occur) in a Perfect Storm.

#### 4.3.1 Caveats to LEI’s Shortfall Risk Assessment

While the results show that New Jersey has enough capacity to meet demand through 2030 under most circumstances, there are a few caveats to keep in mind:

1. LEI’s Shortfall Risk Assessment assumes that off-system peaking resources will continue to be available in the next ten years at the volumes assumed by the GDCs for 2020/21. LEI believes this is a reasonable assumption, as gas demand in New Jersey is set to grow only slowly. In LEI’s Scenario 2b, demand growth of 0.80% per year drives an increase in Design Day Demand of 377 MDth/d from 2020/21 to 2029/30, as shown in Figure 45 above. This reduces the 2020/21 surplus of 573 MDth/d to 274 MDth/d but does not eliminate it.
2. LEI’s Shortfall Risk Assessment for Winter Design Day incorporates 0.80% annual growth. If building electrification occurs, demand will grow more slowly, and the risk of a shortfall would be lower. If for some reason firm demand grows faster, then the risk of shortfall is greater.

### 4.3.2 A note on costs

The arguments for or against adding pipeline capacity often implicitly confuse volumes (which matter to reliability) and prices (which impact costs). The purpose of this engagement and of LEI’s research is to examine reliability, not to develop strategies for minimizing the cost of the mix of supply resources.

However, LEI notes that peaking supplies can be more costly than baseload supplies, though there is a broad range of cost. For example:

- ETG provided information indicating that the cost of off-system supply (demand charges plus commodity costs) contracted for 2020/21 [begin confidential] [redacted]  
[redacted]  
[redacted]  
[redacted]  
[redacted]  
[redacted]  
[redacted]  
[redacted]  
[redacted]  
[redacted] [end confidential].<sup>162</sup>
- NJNG provided the weighted average cost of gas (“WACOG”) for [begin confidential] [redacted]  
[redacted]  
[redacted]  
[redacted]  
[redacted]  
[redacted]  
[redacted]  
[redacted]  
[redacted] [end confidential].<sup>165</sup>
- PSE&G provided information that showed that in the past four years, the cost (demand charge plus commodity charge) of peaking supplies ranged from [begin confidential] [redacted]  
[redacted]  
[redacted]  
[redacted] [end confidential].<sup>166</sup>

<sup>161</sup> ETG. BPU Docket No. GO200010033. Discovery Response 2.4 (Confidential).

<sup>162</sup> ETG. BPU Docket No. GO200010033. Discovery Response 2.1 (Confidential).

<sup>163</sup> NJNG. BPU Docket No GO20010033, Discovery Response 2.2 (Confidential).

<sup>164</sup> NJNG. BPU Docket No GO20010033, Discovery Response 2.2 (Confidential).

<sup>165</sup> NJNG. BPU Docket No GO20010033, Discovery Response 2.2 (Confidential).

<sup>166</sup> PSE&G. BPU Docket No GO20010033, Discovery Responses 2.1-2.8 (Confidential).

- SJG reported that costs for [begin confidential] [REDACTED] [end confidential].<sup>167</sup>

LEI's focus is on the volume of resources, not their costs. Though it is useful to recognize that peaking resources can cost more than baseload resources, a cost minimization exercise is beyond the scope of this assignment.

#### 4.4 Mitigation measures to meet shortfalls

LEI developed a portfolio of non-pipe mitigation options to address the potential for shortfalls of firm capacity. The options were developed based on their alignment with BPU's goals.

##### 4.4.1 Options for meeting the shortfall should align with BPU's goals

Natural gas demand is inherently peaky, driven primarily by demand spikes in the winter months from residential and commercial customers for heating purposes. As a result, any options to meet firm supply shortfalls on peak days should focus on reducing the heating load from these customers, thus reducing the magnitude of these demand spikes or peaks.

The subsections below discuss these shortfall mitigation options through the lens of the Board's overarching priorities or goals. Section 4.4.2 introduces these goals and discusses their relative importance, Section 4.4.3 summarizes the various non-pipeline alternatives which could be implemented to meet future firm supply shortfalls, and Section 4.4.4 compares the options against each of the Board's goals to develop a hypothetical ranking.

##### 4.4.2 Scoring criteria

Through discussion with BPU Staff, LEI developed a list of goals against which each of the NPAs could be scored, namely:

- **improve reliability and resiliency:** gas service to firm customers should be reliable, meaning that gas supply should be available as and when it is needed. To achieve this, gas system infrastructure should be resilient, which a 2013 Presidential Policy Directive on Critical Infrastructure Security and Resilience defines as "the ability to prepare for and adapt to changing conditions and withstand and recover rapidly from disruptions," such as "deliberate attacks, accidents, or naturally occurring threats or incidents."<sup>168</sup>

Taken together, suitable NPAs for implementation should be those that meet potential supply shortfalls while enhancing reliability and system resilience;

- **within the Board's control:** suitable NPAs should be those that can be authorized by the New Jersey BPU, allowing for timely implementation without the need to involve

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<sup>167</sup> SJG. BPU Docket No GO20010033, Discovery Responses 2.3 (Confidential).

<sup>168</sup> US Office of the Press Secretary. [Presidential Policy Directive/PPD-21: Critical Infrastructure Security and Resilience](#). February 12, 2013.

multiple regulatory entities for approval (e.g., as is the case with interstate pipeline projects);

- **build upon current capabilities:** NPAs should leverage capabilities currently in place in New Jersey, such as the communications protocols and platforms established following Hurricane Irene and Superstorm Sandy (see Section 5);
- **consistent with state goals and policies:** NPAs should align with New Jersey’s 2019 Energy Master Plan and Clean Energy Act. The 2019 EMP outlines a goal of reaching 100% clean energy by 2050 through seven key strategies focused mainly on decarbonization,<sup>169</sup> while the 2018 CEA directs GDCs to achieve reductions in gas usage and peak demand, among other efforts;<sup>170</sup>
- **cost effective:** least-cost NPAs should be prioritized over more expensive solutions, so as to minimize the occurrence of stranded costs or assets as the State transitions away from fossil fuels. Stranded costs arise when “events occurring after the utility’s investment have left the utility unable to recover that investment, at least from the customers on whose behalf that investment was made”;<sup>171</sup>
- **enable social equity:** NPAs should enhance social equity, which is a priority reiterated throughout the EMP. For example, the EMP states, “[m]aking energy efficiency policy equitable is crucial to success in meeting New Jersey’s clean energy goals and, with the proliferation of energy efficiency, will enhance equity in the state overall”;<sup>172</sup>
- **technically feasible:** NPAs should be technically feasible within the 2030 timeframe considered for this analysis. Consideration should also be given to each NPA’s degree of flexibility and scalability; and
- **implement within a suitable timeframe:** NPAs should be implementable within the timeframe of the anticipated shortfall.

Notably, while some of these goals might act to reinforce one another, others might be mutually exclusive or at least require trade-offs. These considerations are explored later in Section 4.4.4.

#### 4.4.3 Non-pipeline alternatives

In Section 2.4, LEI reviewed the various non-pipeline alternatives that are being deployed across the nation to offset, defer, or avoid the need for investments in pipeline capacity. Therein, LEI also examined the NPAs that are currently being explored by GDCs in New Jersey.

To summarize, NPAs can generally be categorized into two groups:

1. **demand-side solutions:** these include measures to reduce natural gas demand on the customer-side of the meter, such as energy efficiency programs, demand response

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<sup>169</sup> New Jersey BPU. [2019 New Jersey Energy Master Plan: Pathway to 2050](#). January 27, 2020.

<sup>170</sup> New Jersey State Legislature. [P.L. 2018, Chapter 17, Assembly No. 3723: An Act Concerning Clean Energy](#). May 23, 2018.

<sup>171</sup> Energy Regulation Quarterly. [From Streetcars to Solar Panels: Stranded Cost Policy in the United States](#). September 2015.

<sup>172</sup> New Jersey BPU. [2019 New Jersey Energy Master Plan: Pathway to 2050](#). January 27, 2020. P. 144.

programs that incorporate time of use pricing mechanisms, demand response based on direct load control, and electrification; and

2. **supply-side solutions:** these include solutions to increase the supply of natural gas or alternative fuels that can be injected or blended into the pipeline system, such as renewable natural gas, green hydrogen, or LNG and CNG transported via trucks. LEI also includes advanced leak detection under this category, as the technology enables the reduction in lost and unaccounted-for gas.

#### **4.4.4 Ranking non-pipeline alternatives against key criteria**

LEI examined the various NPAs through the lens of each of the BPU's goals in turn. The following discussion is non-exhaustive in that it does not address every possible consideration for each NPA. Instead, it reflects the range of factors the Board and stakeholders could explore and provides a useful starting point for discussion.

**Improving reliability/resiliency:** diversity supports resiliency by providing alternatives to meeting gas demand if one supply mechanism is disrupted. In this sense, a portfolio approach that implements numerous demand- and supply-side non-pipeline options would be best suited to achieving this goal. For example, on the demand-side, energy efficiency programs can enhance resiliency by ensuring residential customers' homes are better insulated, allowing them to stay warm for longer in the event of a supply disruption. On the supply-side, options such as LNG/CNG trucking can enhance reliability by allowing GDCs to bolster gas supply for limited periods of time, such as during extended cold snaps.

**Within the Board's control:** as discussed in Section 4.4.2, suitable NPAs would likely be those that can be approved and authorized by the BPU, allowing for quicker and more efficient implementation (compared to interstate projects, which would require sign off from regulatory entities at various levels of government and/or from numerous states). For example, while the BPU cannot control production or storage projects that are developed out of state, it does have jurisdiction over New Jersey's GDCs and reducing in-state gas demand. This suggests demand-side, non-pipe mitigation options might be most appropriate for achieving this goal.

**Building upon New Jersey's current capabilities:** NPAs that leverage the State's existing capabilities and resources should be prioritized, as they limit the need for a learning curve during implementation and hence allow for faster progress. For example, energy efficiency programs have been offered by GDCs in some form since 2009 – previous experience and lessons learned can be applied to future iterations, to ensure progress is made in meeting gas demand reduction targets.

**Consistency with state policies and goals:** state policies such as the 2019 EMP and 2018 CEA are focused on decarbonization and reducing gas usage. As such, non-pipe options like LNG/CNG trucking, which increase emissions due to their reliance on fossil fuel for handling, transportation, and injection, are clearly misaligned with these clean energy efforts. In contrast, options such as energy efficiency and some demand response programs are consistent with state policies, as these are required under CEA provisions. However, if customers in DR programs substitute oil for gas (if they use diesel generators, for example), then the DR program would not be aligned with



climate goals. Building electrification efforts are seen as an important strategy under the 2019 EMP to achieving 100% clean energy by 2050.

**Cost effectiveness:** cost effectiveness is an important metric on which to compare NPAs, and as such, should thoroughly weigh as many derived benefits and costs as is feasible. Section 4.5 describes a benefit-cost analysis framework which the state could adopt to evaluate the cost-effectiveness of demand- and supply-side options on a level playing field.

**Enabling social equity:** NPAs such as energy efficiency enable social equity by reducing the energy burden experienced by low-income customers. Energy burden is a measure of the portion of household income spent on home energy costs such as electricity, natural gas, and other home heating fuels.<sup>173</sup> According to the US Department of Energy, energy efficiency programs go beyond reducing heating costs by weatherizing homes, also improving non-energy factors such as indoor air quality, which “results in healthier environments and can decrease sick days and hospital visits for families.”<sup>174</sup>

**Technical feasibility:** NPAs will also need to be assessed according to their current feasibility. For example, options such as green hydrogen are still in the pilot and demonstration phase of development, and as such, are likely years out from becoming commercially viable. Issues around scalability should also be considered. For example, while advanced leak detection has been deployed by GDCs such as PSE&G and ETG, discussions with BPU Staff have indicated that much of the low-hanging fruit has already been picked in terms of pipe replacement. As such, achieving further meaningful reductions in LAUF gas may not be feasible, and should be evaluated before this NPA is deployed at scale.

**Suitable lead time:** somewhat connected to technical feasibility is the Board’s goal of prioritizing NPAs that are implementable within suitable timeframes. As noted above, options such as green hydrogen and RNG are still being demonstrated across the country – as a result, any estimates of their potential as a shortfall mitigation option will need to factor in the anticipated timing of commercial availability. In contrast, options such as energy efficiency and demand response programs have already been proposed by GDCs under the BPU’s *Order Directing the Utilities to Establish Energy Efficiency and Peak Demand Reduction Programs (Docket Nos. QO19010040, QO19060748, and QO17091004)*, and are expected to begin on July 1<sup>st</sup>, 2021.

Figure 46 summarizes these considerations by assigning a score to each option based on the number of goals met. From this exercise, it is clear that some options meet many goals, while other options require certain trade-offs. The scoring methodology is unweighted, meaning each criterion is assumed to have equal weight or importance. The BPU may wish to assign different weights to the criteria (i.e., perhaps improving reliability/resiliency and achieving consistency with state climate targets are more important than building upon current capabilities, or vice

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<sup>173</sup> US DOE. [Low-Income Household Energy Burden Varies Among States – Efficiency Can Help in All of Them](#). December 2018.

<sup>174</sup> Ibid.

versa). The weighted scores would provide another perspective for choosing among the shortfall mitigation options.

**Figure 46. Matrix of shortfall mitigation options and BPU goals**

Criteria	Non-pipe mitigation option							
	Energy efficiency	Voluntary DR program	Direct load control DR	Building electrification	RNG	Green hydrogen	LNG/CNG trucking	Advanced leak detection
Improve reliability/resilience	Yes	Yes	Yes	Somewhat*	Yes	Yes	Yes	Yes
Under the Board's control	Yes	Yes	Yes	Yes	No	No	No	Somewhat
Build upon current capabilities	Yes	Yes	Yes	Somewhat	No	No	No	Somewhat
Consistent with state climate targets	Yes	Somewhat**	Somewhat **	Yes	Yes	Yes	No	Somewhat
Cost effective	TBD							
Enable social equity	Yes	n/a	n/a	Yes	n/a	n/a	n/a	n/a
Technically feasible	Yes	Yes	Yes	Yes	Somewhat	No	Somewhat	Somewhat
Suitable lead time	Yes	Yes	Yes	No	Somewhat	No	Somewhat	Yes
<b>Overall score</b>	<b>7</b>	<b>5.5</b>	<b>5.5</b>	<b>5</b>	<b>3</b>	<b>2</b>	<b>2</b>	<b>4</b>

\* Electrification arguably decreases the resiliency of the electric and gas system as a whole, because it increases the proportion of heating needs in the state met by one energy source (i.e., electricity), reducing the diversity in supplies for heating needs. On the other hand, it frees up gas that would be used for space heating to be used in electricity generation, so it could be argued that it increases resilience.

\*\* Voluntary DR and direct load control programs are scored as being “somewhat” consistent with state climate targets, because the outcome depends on the replacement fuel being used to meet heating needs. For instance, if customers turn down the thermostat on their gas furnaces, but then meet their heating needs through an oil-fired or wood-burning furnace instead, this would not reduce carbon emissions and hence not be consistent with state climate goals.

Note: Overall scores are based on the number of criteria met with a “Yes” (1 point) or “Somewhat” (0.5 point), or “No” (0 points). Higher scores indicate a higher or better rank relative to other shortfall mitigation options.

#### 4.5 Cost-effectiveness of NPAs are system-specific

An important metric on which to evaluate NPAs is their cost-effectiveness. This should be studied within a comprehensive framework that does not only consider costs in isolation, but also factors in the benefits associated with each proposed NPA.

While a thorough benefit-cost analysis (“BCA”) is beyond the scope of this report, LEI presents a BCA framework developed by ConEd in New York, which the utility uses to review and evaluate non-pipeline solutions to “help ensure [it] maintains a cost-effective portfolio of options.”<sup>175</sup> This framework should be thought of as an illustrative case study, which can serve as a starting point from which the BPU, GDCs, and other stakeholders can build to develop an evaluative tool suited to New Jersey’s priorities.

#### Case study: ConEd’s Benefit-Cost Analysis Handbook for Non-Pipeline Solutions

In September 2017, Con Edison proposed a broad program to address its forecasted growing shortfall of peak day capacity in New York. This program included an Enhanced Gas Energy Efficiency Program, a Gas Innovation Program, a Gas Demand Response Pilot as well as a Non-Pipes Alternative (“NPA”) Portfolio, and associated shareholder incentives. The NPA Portfolio

<sup>175</sup> ConEd. [Request for Information: Non-Pipeline Solutions to Provide Peak Period Natural Gas System Relief](#). 2020.

was augmented in September 2018 and subsequently approved in February 2019, comprising \$222 million for demand-side measures.

The approved measures are set to provide some 37 MDth/d of peak day relief. They are mainly demand response and energy efficiency measures:<sup>176</sup>

- targeted **gas energy efficiency for low-income customers and government buildings** that provide critical community services. ConEd expects this program to reduce peak day usage by 25 MDth/d by November 2024; and
- renewable **thermal electrification** proposals for **residential geothermal heat pumps** at 8,800 single-family residences in Westchester County and air source heat pumps for 1,000 multifamily buildings in the Bronx. ConEd expects these measures to reduce demand by 12.4 MDth/d over the same time period.

To date, the utility has issued two competitive solicitations (one in December 2017 and another in January 2020) seeking NPA proposals from vendors, suppliers, and customers to “provide natural gas supply or demand relief during peak days and peak periods.”<sup>177</sup>

Con Edison developed a BCA framework for its non-pipeline solutions in 2018, “to assist in the evaluation of demand-side reductions and/or non-traditional local supply-side additions.”<sup>178</sup> These NPA proposals are evaluated and compared through the BCA framework, which relies on three tests to assess cost-effectiveness – the societal cost test, utility cost test, and rate impact measure (see Figure 47).

**Figure 47. Cost-effectiveness tests used in ConEd’s BCA framework**

Cost effectiveness test	Key question answered	Approach
<b>Societal cost test</b>	Is the utility, state, or country <b>better off</b> as a whole?	Compares the incremental costs incurred to deliver the proposed solution against the avoided costs and benefits to society (e.g., reductions in GHG emissions)
<b>Utility cost test</b>	How will <b>utility costs</b> be affected?	Considers the costs and benefits accrued directly to the utility
<b>Rate impact measure test</b>	How will <b>utility rates</b> be affected?	Considers the impact of proposed solutions on non-participating firm natural gas customers

Sources: ConEd. [Request for Information: Non-Pipeline Solutions to Provide Peak Period Natural Gas System Relief](#). 2020; IESO. *Conservation & Demand Management Energy Efficiency Cost-Effectiveness Guide*. April 1, 2019.

<sup>176</sup> Sources: New York Public Service Commission. Case 17-G-0606 - Petition of Consolidated Edison Company of New York, Inc. for Approval of the Smart Solutions for Natural Gas Customers Program. Order Approving with Modification the Non-Pipelines Solution Portfolio. February 7, 2019.

<sup>177</sup> ConEd. [Request for Information: Non-Pipeline Solutions to Provide Peak Period Natural Gas System Relief](#). 2020.

<sup>178</sup> ConEd. *Interim Benefit Cost Analysis Handbook for Non-Pipeline Solutions (Case 17-G-0606)*. September 28, 2018.

The framework outlines the key benefit and cost factors that should be considered and quantified (wherever possible) when evaluating NPAs. Benefits include:<sup>179</sup>

- **fixed and variable avoided upstream supply:** reflects the benefits (or avoided costs) of NPAs from not needing to acquire or invest in pipeline infrastructure or incremental gas supply resources;
- **avoided distribution expense:** reflects the benefits (or avoided costs) from not needing to invest in on-system distribution infrastructure, including the costs associated with the expansion or upgrade itself, as well as ongoing maintenance costs avoided throughout the lifetime of the NPA project or program;
- **reliability/resiliency:** reflects the benefits of NPAs in the form of improved system resiliency, such as providing pressure support at key locations, avoiding system outages altogether, or recovering more quickly from system outages; and
- **external benefits:** reflects indirect benefits stemming from the NPA project or program, such as reduced emissions or other societal benefits.

Costs include:<sup>180</sup>

- **program administration:** reflects the costs directly associated with implementing an NPA project or program;
- **incremental distribution:** captures any infrastructure costs that the GDC must incur to support the deployment of an NPA project or program;
- **lost utility revenue:** accounts for lost gas revenues from reduced gas consumption and/or a decrease in the number of customers served;
- **participant NPA cost:** reflects costs incurred by developers of NPA projects (e.g., RNG), or by customers participating in NPA programs (e.g., EE, DR, electrification), net of payments from GDCs to developers or incentives/rebates to customers;
- **alternative fuel costs (i.e., electricity):** reflects the costs associated with using an alternative energy source for a service previously provided by gas (e.g., heating); and
- **external costs:** reflects indirect costs stemming from the NPA project or program, such as increased emissions or other societal costs.

Demand-side options such as energy efficiency, demand response, and electrification may enable GDCs to avoid investments in upgrading or expanding the gas distribution system (and so avoid distribution costs), while supply-side options would most likely require these costs to be incurred (e.g., to connect an RNG project to the system) (see Figure 48).

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<sup>179</sup> ConEd. *Interim Benefit Cost Analysis Handbook for Non-Pipeline Solutions (Case 17-G-0606)*. September 28, 2018.

<sup>180</sup> Ibid.

Figure 48. Benefit and cost categories for each NPA

Consideration	Non-pipe mitigation option							
	Energy efficiency	Voluntary DR program	Direct load control DR	Electrification	RNG	Green hydrogen	LNG/CNG trucking	Advanced leak detection
<b>Benefits</b>								
Fixed and variable avoided upstream supply	●	●	●	●	●	●	●	●
Avoided distribution expense	○	○	○	○	○	○	○	○
Reliability/resiliency	○	○	○	○	○	○	○	○
External benefits	○	○	○	○	○	○	○	○
<b>Costs</b>								
Program administration	●	●	●	●	●	●	●	●
Incremental distribution	○	○	○	○	●	●	●	●
Lost utility revenue	●	○	○	●	○	○	○	○
Participant NPA cost	○	●	●	●	●	●	●	○
Alternative fuel costs (electricity)	○	○	○	●	○	○	○	○
External costs	○	○	○	○	○	○	○	○

● Generally applicable      ○ Maybe applicable      ○ Limited or no applicability

Note: ConEd assessed the applicability of each consideration for the following NPAs only: energy efficiency, demand response, electrification, RNG, and LNG/CNG supply projects. LEI extended this analysis to the other NPAs currently under review – namely, green hydrogen and advanced leak detection.

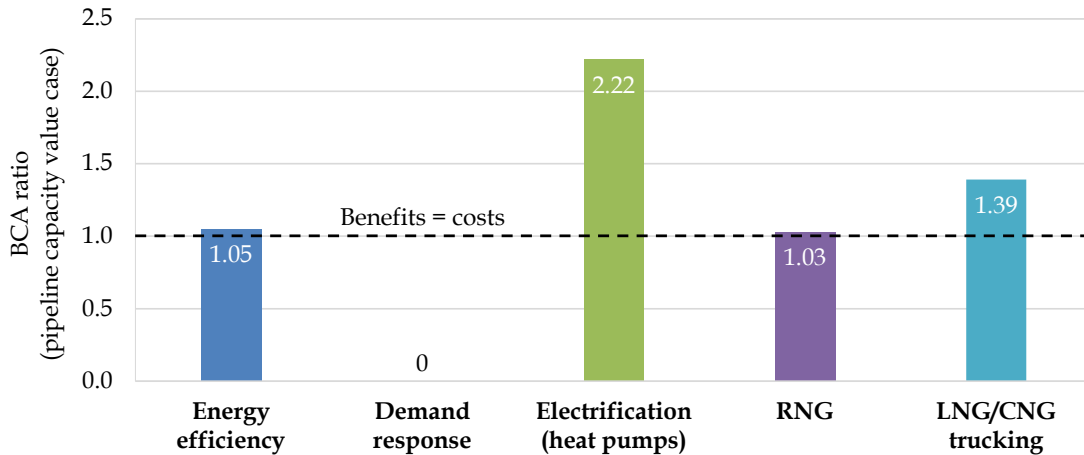
Source: Con Edison. *Interim Benefit Cost Analysis Handbook for Non-Pipeline Solutions (Case 17-G-0606)*. September 28, 2018.

Con Edison applied the BCA framework to the NPA proposals it received through its 2017 solicitation – the results of its analysis are illustrated in Figure 49 (under a sensitivity case where “the benefits provided by solutions was valued based on the avoided projected cost of a pipeline expansion project”). For example, Con Edison estimated that the credible proposals it received for RNG projects achieved a BCA ratio of 1.03 – implying that the benefits of these bids outweighed the costs by 3%.<sup>181</sup>

This ranking of NPAs relates specifically to the bids and proposals received by Con Edison – *the BCA ratios will differ if the framework is adjusted to reflect GDC costs and benefits to New Jersey*. However, it illustrates the type of cost-effectiveness estimates which can be developed using the BCA framework, from which various demand- and supply-side options can be evaluated on a level playing field.

<sup>181</sup> Con Edison. *Case 17-G-0606 – Petition of Consolidated Edison Company of New York, Inc. for Approval of the Smart Solutions for Natural Gas Customers Program*. September 28, 2018.

Figure 49. ConEd’s BCA ratio estimates for various NPAs



Note: According to ConEd, proposed DR projects received low scores in the BCA and were excluded from the NPA portfolio because 1) demand response was expected to be activated on only a small number of days each winter season and would, therefore, reduce gas consumption only a small amount over the course of a winter season, and 2) some measures would use electricity instead of natural gas on peak winter days, which would likely increase the use of oil to fuel electric generation.

Source: ConEd. Case 17-G-0606 – Petition of Consolidated Edison Company of New York, Inc. for Approval of the Smart Solutions for Natural Gas Customers Program. September 28, 2018.

#### 4.6 Pipeline capital costs provide a benchmark

Though the costs and benefits of the NPAs will depend on the system, costs associated with traditional pipeline options provide a useful benchmark for comparison. The average cost of a smart gas thermostat is about \$150/thermostat; many utilities offer a rebate for customers to install one. If the NJ GDCs offered a \$100 rebate per thermostat, the cost would be \$313 million if every customer took up the offer (see Figure 50). This would be less expensive than LEI’s estimate what PennEast would have cost GDC customers (about \$365.8 - \$ 603.6 million) (see Figure 51).

Figure 50. Cost of smart thermostats

Customer Type	2020				Total
	ETG	PSE&G	NJNG	SJG	
Residential	277,852	1,700,266	497,779	378,103	
Commercial	23,663	158,167	28,735	26,369	
Industrial	98	6,242		414	
Other		16	31,652		
<b>Total customers</b>	<b>301,613</b>	<b>1,864,691</b>	<b>558,166</b>	<b>404,886</b>	<b>3,129,356</b>
<b>Cost of smart thermostats assuming utility pays \$100 rebate</b>					
\$ million	\$ 30	\$ 186	\$ 56	\$ 40	\$ 313

Sources: Customer numbers: SEC 10-K Form filings, smart thermostat costs. <<https://marketplace.socalgas.com/> and <https://enrollmythermostat.com/faqs/socalgas-faq/>>

**Figure 51. Back-of-the-envelope GDC cost estimate for PennEast Pipeline**

	Low end	High end
Range of cost estimates (billion)	\$ 1.00	\$ 1.65
Project size (MDth/d)	1,107	1,107
<b>Range of cost (per MDth/d)</b>	<b>\$ 903,342</b>	<b>\$ 1,490,515</b>
Capacity under agreement with GDCs (MDth/d)	405	405
<b>Capital cost to be covered by reservation rate (\$)</b>	<b>\$ 365,853,659</b>	<b>\$ 603,658,537</b>

\*Assumes the capacity beyond the 405 MDth/d which was under GDC precedent agreement was paid for by reservation charges to non-NJ GDC shippers. LEI did not include interest or other costs in this back-of-the-envelope calculation.

Sources: Capital cost, project size: Supreme Court of the United States. PennEast Pipeline Company, LLC, Petitioner v. New Jersey, et al. Petition appendix. February 18, 2020.

<<https://www.supremecourt.gov/docket/docketfiles/html/public/19-1039.html>>

#### 4.7 A portfolio approach can address a potential weather-driven shortfall

LEI believes a portfolio approach comprising a variety of NPAs would be best suited to meeting potential supply shortfalls while ensuring the reliability of gas service is maintained for firm customers. A portfolio approach ensures diversity in non-pipeline mitigation options, which further supports resiliency.

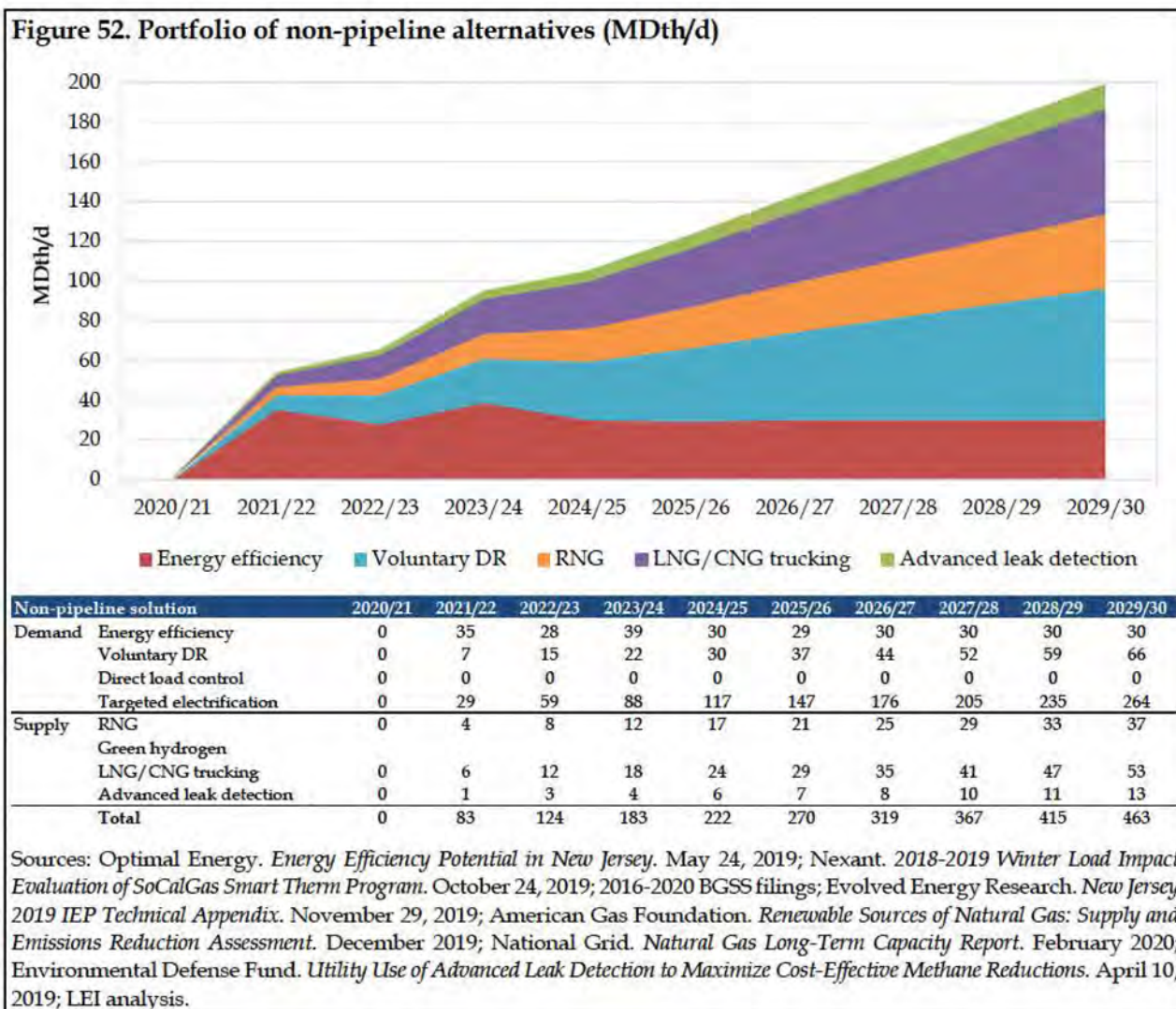
LEI developed an outlook for each NPA, creating a portfolio of options for meeting the projected shortfall of 153 MDth/d by 2030 in a 1-in-90 winter. The NPA outlook is projected based on the estimates discussed previously in Section 2.3 and Section 2.4. For reference, on the demand side, they are:

- **Energy efficiency:** LEI assumes GDCs meet Board ordered energy efficiency targets in line with the 2018 CEA. For the supply stack in Figure 52, LEI assumes GDC energy efficiency programs achieve additional savings above and beyond these targets, to meet the “maximum achievable potential” for the 2021-2030 period, as outlined in Optimal Energy’s Market Potential Study. This amounts to an added 30 MDth/d in peak demand reductions by 2030.
- **Voluntary demand response:** LEI assumes the GDCs distribute smart thermostats to customers within their service territory to shave peak demand in emergency situations. To estimate the additional savings achieved, LEI this time applied SoCalGas’ 1.76% daily savings rate for each GDC’s projected firm sendout for 2030. This amounts to 66 MDth/d in peak demand reductions by 2030.
- **Targeted electrification:** The Least Cost scenario under New Jersey’s Integrated Energy Plan projects that annual consumption of pipeline natural gas could be reduced by 96 TBtu from 2020 to 2030, through an initial wave of space and water heating electrification efforts. To estimate the resulting impact on peak day demand, LEI divides the value by 365 – this amounts to an added 264 MDth/d in peak demand reductions by 2030. This methodology assumes gas demand is constant throughout the year. While this amount is

omitted from the supply stack in Figure 52 to align with LEI's conservative approach to forecasting, it is included in the table for reference.

For reference, on the supply side, the options are:

- **RNG:** LEI assumes that by 2030, New Jersey achieves RNG production in line with the American Gas Foundation's state-level estimates under a Low Resource Potential scenario, assuming RNG is produced via anaerobic digestion only. This amounts to an added 37 MDth/d in on-system gas supply by 2030.
- **LNG/CNG trucking:** LEI assumes that by 2030, GDCs implement LNG/CNG trucking solutions that match the expanded capacity proposed by National Grid for its two New York facilities (which equates to approximately 108 trucks per day). This amounts to an added 53 MDth/d in on-system gas supply by 2030.
- **Advanced leak detection:** LEI assumes that by 2030, GDCs utilize ALD technology to reduce methane emissions from distribution pipe leaks by 25%. This amounts to an added 12.5 MDth/d in gas supply by 2030.





Not including targeted electrification, New Jersey could more than make up a 153 MDth/d shortfall in a 1-in 90 winter in 2030 (see Figure 52), assuming the supply and demand projections enumerated above get under way as assumed.

LEI did not include building electrification in the area chart in Figure 52 because Scenario 2b conservatively assumes that no additional building electrification would occur. However, if it did, it could account for 264 MDth/d of NPA (as shown in the table portion of Figure 52); and even if only half of the building electrification target were met, it would account for a large portion of a potential shortfall in a 1-in-90 winter.

#### **4.8 The BPU should revisit this risk assessment in 2025**

LEI recommends that the BPU update the Shortfall Risk Assessment in 2025 to aid New Jersey's gas planning process – such an exercise would achieve the following:

- **account for any changes in demand outlooks:** the current Shortfall Risk Assessment projects no supply shortfall based on the Winter Design Day condition, but the potential for shortfalls in extreme weather (i.e., the 1-in-90 Design Day condition). However, over time GDCs might observe that firm demand tracks closer to the Historical Peak Day condition, in which case the risk for future shortfalls could be downgraded. In contrast, GDCs might utilize higher HDD assumptions going forward in their design day forecasts, in which case the risk of future shortfalls could be higher;
- **account for any changes in supply outlooks:** the Shortfall Risk Assessment should be updated to account for any changes in FT capacity, on-system peaking resources, or other sources of firm supply. This would ensure that GDCs are planning for future shortfalls that are calculated based on the latest available information; and
- **track progress in implementing NPAs:** the BPU can use this exercise to measure GDCs' progress in implementing various NPAs. The BPU could also engage stakeholders at this point to gather their feedback on GDC progress, as well as to potentially reassess the State's priorities for the gas sector.

## 5 Best Practices and Playbook

This section outlines best practices based on (i) lessons learned from other jurisdictions faced with energy emergencies, and (ii) New Jersey's starting point, so that the practices build upon processes already in place in New Jersey. It then presents a Playbook for coping with emergency shortfalls in gas supply.

### 5.1 Key takeaways

- **As learned the hard way in Texas in February 2021, rules will be ignored without enforcement:** Recommendations must become rules which are mandatory and enforceable, either through incentives or penalties. The development of enforceable rules may require stakeholder consultation and input. However, without formalization, New Jersey risks finding itself in a situation whereby significant disruption occurs despite policymakers and first responders having the knowledge and expertise to prevent them;
- **Focus on strategies under the BPU's control:** Demand-side measures, incentives and penalties in the context of the regulatory regime, and communications are all under the control or direct influence of the BPU;
- **Build on existing platforms:** Expanding on the current communications protocol has low marginal costs because the communications system has already been built, so modifying it will take little lead time and be relatively low cost;
- **Begin now:** Make sure the tools and infrastructure are in place, so that when disaster strikes, the plans that depend on the tools can be implemented.

Based on the best practices, LEI developed a Playbook for responding to three levels of supply shortfall. In summary, they are:

- **Elevated (Yellow) Alert** Potential Winter Design Day conditions, where, while no shortfall of supply is necessarily predicted, customers would be encouraged to conserve gas (see below).
- **Critical (Orange) Alert:** Potential 1-in-90 Design Day conditions with a shortfall of up to about 150 MDth/d. Assuming all NPAs are in place, there would be no need for direct load control; however, if NJ is aware that NPAs have not reached target levels, then the State needs to be ready to implement direct load control. Minimal direct load control (1-3 degrees on average for all firm customers) would be implemented to make up for any shortfall in the other NPAs shown in Figure 52 previously.
- **Emergency (Red) Alert:** LEI defines a Red Alert as a condition which involves the need for substantial direct load control, such as a Perfect Storm, combining a Winter Design Day and a 900 MDth/d outage on a major pipeline, for a shortage of 525 MDth/d as posited in Section 4. Direct load control would be evoked, and effective coordination by the BPU may minimize the impact on customers. The Governor's Office and others would be involved in communications.

## 5.2 Best practices

### 5.2.1 Learn from previous failures and successes

To ensure LEI's recommended best practices are grounded in real-life experiences, LEI examined three previous disasters, their impacts on the electric and gas systems, and the response of the authorities. These are the Texas Groundhog Day winter storm of 2011, the Polar Vortex of 2014, and the impacts of Hurricanes Irene and Sandy (see Appendix 2 (Section 7) for more details). LEI observed:

- **Groundhog Day in Texas:** In response to the Groundhog Day winter storm in 2011 which left thousands of customers without electricity or gas, regulators and legislators in Texas failed to implement enforceable rules and regulations. This set the stage for a repeat of the events and their consequences in February 2021, but on a much more devastating scale.
- **Polar Vortex in PJM:** In response to the 2014 polar vortex, the PJM electric system operator instituted Capacity Performance ("CP") incentives as an integral part of its forward capacity market to make sure that electric generating capacity would be available during a crisis.<sup>182</sup> The CP rules were "*intended specifically to encourage resources to make needed upgrades in plant equipment, weatherization measures, fuel procurement arrangements, fuel supply infrastructure and other factors.*"<sup>183</sup> The CP structure incorporates bonuses and penalties. Not being able to access natural gas is not an excuse for a gas plant that has cleared the capacity market not to run; and if that is the case and the plant has a capacity award, the plant will be penalized for not generating if called upon.
- **New Jersey's response to Hurricanes Irene and Sandy:** As detailed later in Section 5.2.3, New Jersey developed a communications platform as well as requiring GDC investments in hardening gas infrastructure.

Texas's response to the 2011 Groundhog Day storm compared with PJM's response to the 2014 Polar Vortex illustrates what not to do when developing an emergency plan for the electric and gas systems:

1. Fail to recognize that the gas and electric systems are interdependent;
2. Fail to codify winterization or other requirements into regulations; and
3. Fail to impose penalties for non-compliance.

These three "don'ts" translate into "dos," or best practices, for gas reliability in New Jersey:

1. Recognize, in policy and in regulations, that the **gas and electric systems are interdependent**;
2. **Codify requirements into enforceable regulations**; and

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<sup>182</sup> "Strengthening Reliability: An Analysis of Capacity Performance." *PJM Interconnection*. June 20, 2018.

<sup>183</sup> *Ibid.*

### 3. Inspect, verify, and impose penalties for non-compliance.

Figure 53. Case study summary: Key lessons for New Jersey

High impact event	Key observations during the event	Key lessons/takeaways
Texas: Groundhog Day Storm of 2011	<ul style="list-style-type: none"> <li>Significant outages reported in both the electric and natural gas sectors</li> <li>Culminated in rolling blackouts and gas curtailments</li> <li>Issues identified included insufficiency of black start generation units, lack of appropriate winterization and vulnerable interconnected nature of gas and electricity sectors</li> </ul>	<ul style="list-style-type: none"> <li>Example of <b>what not to do</b>, as appears similar issues re-emerging in 2021</li> <li><b>Voluntary guidelines</b> are likely to be ignored</li> <li>Recommendations should be codified into <b>mandatory rules</b> that are enforceable</li> </ul>
Northeast Polar Vortex of January 2014	<ul style="list-style-type: none"> <li>Severe polar vortex caused multiple operational flow orders (“OFOs”)</li> <li>Natural gas compressor outage along Tetco pipeline at Delmont, PA</li> <li>Over 2.8 GW of unplanned outages of natural gas plants caused by gas supply issues</li> </ul>	<ul style="list-style-type: none"> <li>Capacity Performance (“CP”) rules created and implemented by the system operator, PJM</li> <li>CP rules include <b>penalties for non-performance</b> by plants</li> <li>Recent experience during cold snaps in 2017/2018 suggests that the <b>rules have worked</b></li> </ul>
Hurricanes Irene and Sandy	<ul style="list-style-type: none"> <li>Consecutive hurricanes in 2011 and 2012 made landfall in New Jersey</li> <li>Hurricane Sandy resulted in more significant damage to gas infrastructure</li> <li>Lessons from Irene incorporated into response from Sandy, such as establishment of a fusion center known as the ROIC</li> </ul>	<ul style="list-style-type: none"> <li><b>Communications protocols</b> were critical during Hurricane Sandy</li> <li>New Jersey BPU instituted the “March 20 Order” requiring GDCs to submit <b>storm mitigation plans</b></li> <li>Storm hardening investments have since been undertaken by all GDCs</li> </ul>

#### 5.2.2 Focus on strategies under the BPU’s control

LEI recommends focusing on strategies which are under the control or influence of the BPU.

##### 5.2.2.1 Put in place demand-side tools, and the rewards and penalties needed to make them work

New Jersey is reliant on out-of-state gas resources, so the BPU has limited oversight over supply measures. Among all the options available to the BPU, demand-side tools are under the full purview of the BPU. The BPU can (and has) required resiliency investments on the GDC side of the meter, as discussed below. Equally, the BPU can allow cost recovery for the required installation of controllable thermostats on the customer side.

##### 5.2.2.2 Consider resiliency attributes in Infrastructure Improvement Program evaluation

New Jersey’s existing framework already allows for cost recovery for utilities investing in their networks under the Infrastructure Improvement Program (“IIP”). The IIP is mandated under the Infrastructure Investment and Recovery (“II&R”) regulations, which established a regulatory mechanism that allows for a utility to accelerate its investment in the construction, installation, and rehabilitation of “*certain non-revenue producing utility plant and facilities that enhance safety,*

reliability, and/or resiliency.”<sup>184</sup> These regulations were effected in January 2018, and through the IIP, a GDC may qualify for accelerated cost recovery of eligible investments, subject to the terms of the subchapter, and any other conditions set forth by the BPU.

As indicated in the rules, eligible projects for the IIP must be related to “safety, reliability, and/or resiliency” as well as three other factors (i.e., be non-revenue producing; specifically identified by the utility within its petition; and approved by the BPU for inclusion in the IIP).<sup>185</sup>

One measure that could be considered to augment this rule is to include a premium for resiliency attributes associated with infrastructure improvements. This would entail augmenting the framework that is currently used to evaluate infrastructure enhancement proposals from utilities with extra weight placed on resiliency attributes (e.g., the attributes of equipment such as that needed for direct load control) that could help the system cope with extreme weather events or design day demand. This puts an additional value on benefits that may not be quantifiable in dollar terms.

### **5.2.2.3 Phase out incentives to switch from oil to gas heating**

Although it may be controversial, New Jersey should consider eliminating incentives to switch from oil to gas heating. An obvious step towards building electrification is to stop subsidizing near-term consumer choices that are at odds with long-term goals. Gas furnaces have long, useful lives, so discouraging their uptake will have long-term impacts on reducing natural gas reliance.

Currently, the NJ CEP, as administered by the NJ BPU’s Division of Clean Energy offers incentives for switching from oil to gas heating. For example, under the WARMAdvantage program, customers may be eligible for rebates of between \$250 to \$500 if they switch to a gas furnace of a minimum qualifying efficiency.<sup>186</sup> This rebate also exists for boilers, and ranges from \$300 to \$700 if the customer installs an integrated water heating and boiler unit, under a combination program.<sup>187</sup>

The program budget of NJ CEP is substantial, including over \$82 million for the period June 2019 to June 2020 for residential programs.<sup>188</sup> Over the same period, the WARMAdvantage program processed rebates for over 11,200 installations of furnaces, boilers, and hot water heaters.

### **5.2.3 Build on infrastructure and processes already in place**

An effective strategy is usually grounded in capabilities that an organization already has in place—i.e., its strengths. New Jersey’s actions in response to Hurricanes Irene and Sandy have

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<sup>184</sup> New Jersey Administrative Code. § 14:3-2A. *Subchapter 2A. Infrastructure Investment and Recovery.*

<sup>185</sup> New Jersey Administrative Code § 14:3-2A.2

<sup>186</sup> New Jersey Clean Energy Program website. WARMAdvantage. Furnaces. <<https://njcleanenergy.com/residential/programs/warmadvantage/furnaces-and-boilers>>

<sup>187</sup> Ibid.

<sup>188</sup> New Jersey Clean Energy Program. *New Jersey’s Clean Energy Program Report Submitted to the New Jersey Board of Public Utilities.* 4QFY20 Final Report.

resulted in plans and infrastructure it can leverage to help avert and mitigate a gas supply shortage.

### 5.2.3.1 Emergency communication platform

During Hurricane Sandy, several GDCs adopted measures learned from Hurricane Irene. PSE&G used its GIS system alongside the National Weather Service's river forecast to predict areas of high-risk flooding and the possible impacts. PSE&G set up field command centers to manage restoration activities and provide direct contact between its employees and its customers to address 9,000 natural gas emergencies.<sup>189</sup> NJNG also took measures to mitigate the effects of the hurricane, with emphasis on communication with customers. NJNG's Facebook page was a major source of information for customers, allowing customers to communicate with the utility as well as for the utility to provide updates on restoration activities.<sup>190</sup>

In addition to individual GDC communications, the New Jersey Regional Operations and Intelligence Center ("NJ ROIC") provided official information for the citizens of New Jersey prior to, during, and after Hurricane Sandy. The text box below outlines the NJ ROIC and the role it played throughout Hurricane Sandy.

#### New Jersey Regional Operations & Intelligence Center

The ROIC, the state of New Jersey's intelligence fusion center, is responsible for maintaining statewide situational awareness for response to current and future security issues in the state. The ROIC collects, analyzes, and disseminates criminal intelligence and other information to support the efforts of law enforcement and public safety agencies in New Jersey.

Prior to and during Hurricane Sandy, the NJ ROIC and New Jersey's State of Emergency Operations Center ("SEOC") used the ROIC system and network to relay situation reports that included up-to-the-minute information about the overall state of the disaster. Following the storm, ROIC provided parties with information, maps, and other public safety information. ROIC's personnel were deployed to collect information related to the condition of government buildings and infrastructure.

Sources: "Fusion Center Coordinates New Jersey Hurricane Sandy Disaster Response." *Department of Homeland Security*, October 2012.

### 5.2.3.2 GDCs required to harden infrastructure, and compensated for doing so

Following Hurricane Sandy, NJ BPU issued the March 20 Order, which required NJ GDCs to submit cost-efficient and effective opportunities with the potential to enhance natural gas infrastructure to protect against damage from major storm events.<sup>191</sup> Following the March 20

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<sup>189</sup> "Hurricane Season 2013: The Calm Before the Storm." *American Gas Association*. June 2013.

<sup>190</sup> *Ibid.*

<sup>191</sup> New Jersey Board of Public Utilities. Docket No. EX13030196. In the Matter of the Board's Establishment of a Generic Proceeding to Review the Prudency of Costs Incurred by New Jersey Utility Companies in Response to Major Storm Events in 2011 and 2012. March 20, 2013.

Order, all four New Jersey GDCs submitted storm mitigation plans to the BPU, which were subsequently approved.

PSE&G proposed and was approved for a \$1 billion Energy Strong Storm Mitigation Plan, of which \$400 million was related to natural gas infrastructure.<sup>192</sup> This included infrastructure hardening measures such as substation flood mitigation, upgrades to the gas distribution system, and installation of advanced technologies.<sup>193</sup> PSE&G was authorized by the NJ BPU to recover costs incurred by the Energy Strong Storm Mitigation Plan through a special rate adjustment mechanism called the Energy Strong Adjustment Mechanism (“ESAM”).<sup>194</sup>

NJNG invested \$102.5 million through its New Jersey Reinvestment in System Enhancements (“NJ RISE”) program into six infrastructure projects.<sup>195</sup> NJ BPU authorized NJ RISE Program expenditures to be recovered through base rate adjustments in the future.<sup>196</sup> SJG invested \$103 million through its Storm Hardening and Reliability Program (“SHARP”), replacing low-pressure mains, eliminating regulator stations, and installing excess flow valves.<sup>197</sup> Expenditures incurred through SHARP were authorized for recovery through annual base rate adjustments.<sup>198</sup> ETG invested \$14.9 million, through its Elizabethtown Natural Gas Distribution Utility Reinforcement (“ENDURE”) Plan, that included the elevation of three gate station facilities.<sup>199</sup> NJ BPU approved the inclusion of costs incurred by the ENDURE Plan in customer rates.<sup>200</sup>

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<sup>192</sup> New Jersey Board of Public Utilities. *In the Matter of the Petition of Public Service Electric and Gas Company for Approval of the Energy Strong Program*. May 21, 2014.

<sup>193</sup> “New Jersey Five Years Post-Sandy: Stronger Than the Storm.” *New Jersey Department of Community Affairs*. October 2017.

<sup>194</sup> New Jersey Board of Public Utilities. *In the Matter of the Petition of Public Service Electric and Gas Company for Approval of an Increase in Electric and Gas Rates and for Changes in the Tariffs for Electric and Gas Service, B.P.U.N.J. No. 16 Electric and B.P.U.N.J. No. 16 Gas, and for Changes in Depreciation Rates, Pursuant to N.J.S.A. 48:2-18, N.J.S.A. 48:2-21 and N.J.S.A. 48:2-21.1, and for Other Appropriate Relief*. August 8, 2018.

<sup>195</sup> *Ibid.*

<sup>196</sup> New Jersey Board of Public Utilities. *In the Matter of the Petition of New Jersey Natural Gas Company for Approval of Base Rate Adjustments Pursuant to its NJ RISE and SAFE II Programs*. September 9, 2020.

<sup>197</sup> *Ibid.*

<sup>198</sup> New Jersey Board of Public Utilities. *In the Matter of the Petition of South Jersey Gas Company for Approval of Base Rate Adjustments Pursuant to the Storm Hardening and Reliability Program (“SHARP II”)*. September 23, 2020.

<sup>199</sup> *Ibid.*

<sup>200</sup> New Jersey Board of Public Utilities. *In the Matter of the Petition of Pivotal Utility Holdings, Inc. D/B/A Elizabethtown Gas for Approval of Increased Base Tariff Rates and Changes for Gas Service and Other Tariff Revisions*. June 30, 2017.

## 5.2.4 Begin now

As will become clear in the Playbook, New Jersey will have the capability to withstand even large natural gas supply shortfalls *if it plans ahead*. However, as of today, important NPA tools are not yet in place. The BPU has the authority to allow cost recovery and tariffs to support the cost of such equipment and can develop a communications program and use it (as described in Section 5.3). However, neither the NPA tools nor plan of implementation is in place or at scale yet.

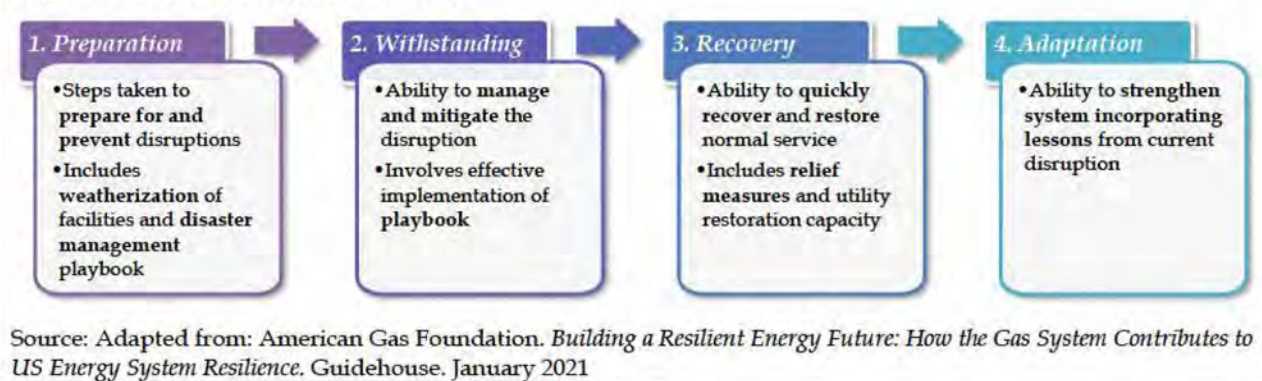
*"An ounce of prevention is worth a pound of cure."*  
- Benjamin Franklin

## 5.3 Playbook for emergencies

The Playbook focuses on preparing for gas supply shortfalls during a 1-in-90 Design Day or Winter Design Day plus supply disruption (Perfect Storm conditions). Having a playbook in place ahead of time means no time is lost figuring out what to do when an emergency is about to unfold.

The American Gas Foundation ("AGF") proposes a four-phase framework for coping with an emergency: Preparation, Withstanding, Recovery, and Adaptation (see Figure 54). Preparation is the most important step – without tools in place, or a plan to use them, withstanding the impact of an event and recovery from the event are that much harder. Therefore, LEI's Playbook focuses on Preparation. Mitigation and Recovery plans have already been developed, as LEI understands, by the GDCs. Adaptation is incorporated into LEI's Preparation phase.

Figure 54. AGF four-phase framework



### 5.3.1 Preparation: Develop the tools and the plan

Most of this Playbook is about what to do ahead of time. When the emergency strikes, what needs to be done is to implement the Playbook, but that will only work if the tools and plan are in place. As observed in the experience of Texas, recommendations are useless if they are not enforceable. The tools that LEI believes need to be in place are a combination of:

1. **coordination strategies** (across agencies, and across gas and electric operators);
2. **equipment** (e.g., smart thermostats, winterized equipment, hardened infrastructure);



3. pre-event **communications platforms and protocols** (yellow-orange-red alerts as described below); and
4. **enforceable regulations** based on penalties and rewards, in place ahead of time.

LEI discusses each of these below.

#### **5.3.1.1 Coordinate agencies across gas and electric systems**

New Jersey has had experience with natural disasters and may already have a clear system of accountability in place. If not, the BPU could assume the role of the primary coordinator of the statewide emergency efforts with respect to the gas sector, if the role of the primary coordinator is not already explicit in New Jersey.

As a best practice is to recognize the interrelation of electricity and natural gas, key operational decision-makers at PJM, the gas transmission pipelines, and at the GDCs must be equipped with a means of communication which is established and tested ahead of time. Some of this may already exist in New Jersey.

The National Association of Regulatory Utility Commissioners (“NARUC”) identified key success factors for coordination strategies between relevant agencies during energy-related events:<sup>201</sup>

- ***Strong inter-organizational relationships:*** cooperation between agencies is built on clearly documented roles and responsibilities and joint problem solving, that may or may not be mandated by statute-based authority. For example, the California Public Utilities Commission (“CPUC”) and the Governor’s Office of Emergency Services have a memorandum of understanding (“MOU”) that allows gas utilities and fire service emergency responders to collaborate on training exercises. These cross-training exercises allow the teams to ensure the first responders are aware of techniques to address gas fires.
- ***Regular communication between agencies before, during, and after emergencies:*** the regulator, energy office, and emergency management office need to have a routine and established lines of communication in place, to maintain situational awareness and effectively leverage each other’s efforts during emergencies. This can be achieved through simple tools such as conference calls, or web-based platforms to promote incident management.
- ***Implementation of drills, tabletop exercises, and workshops:*** Coordinating agencies should meet and exercise their response roles at least once a year, and more frequently if a seasonal forecast suggests the greater risk is looming.

#### **5.3.1.2 Develop and implement enforceable regulations based on penalties and rewards**

This is what LEI suggests:

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<sup>201</sup> Acho, Matthew & Constantini, Lynn. [State Agency Coordination During Energy-Related Emergencies](#). NARUC Center for Partnerships & Innovation.

- **Require each utility to have a worst-case emergency plan at hand.** GDCs should be required to develop and regularly update a worst-case technical prevention and recovery plan. This plan would utilize a common reporting template and/or reporting requirements determined by the BPU, but could include at a minimum:
  - **Identification of critical gas infrastructure** that should remain online throughout an emergency event—this information must be supplied to the electric system operator;
  - **Segmentation of the GDC network** such that statewide coordinators can easily identify areas that can be shut off without impacting others. For example, senior housing complexes and locations which host other vulnerable populations should be served even if gas service to nearby areas must be shut off;
  - **Facility prioritization**, i.e., the GDC should indicate the order in which facilities should be shut off in the event of an emergency; and
  - **Plan for regular updates**, which provide a timeframe in which the GDC will update its plans, ideally every two to three years.

While these plans may never be implemented, they will form critical knowledge in the event of an emergency alert.





### **5.3.1.3 Build yellow-orange-red alert protocol on the communications platform**

New Jersey has already implemented the NJ ROIC as a centralized communications and coordination center during a crisis. This can be used before a crisis even begins, however, as well as help to mitigate it as it has been designed to do.

LEI recommends building a simple and intuitive alert framework, which is color-coded to correspond to the severity of the event or pending event. Each alert level corresponds to a set of actions to be taken by the BPU and/or the GDCs, and the information that is shared with customers (see Figure 55). The framework would be harmonized across all utilities, and the state can provide an online map showing various regions by emergency color, as not all customers in New Jersey may be experiencing the same severity of outages/threat level.

A color-coded communications protocol is simple to introduce and understand from a customer perspective, but coordinating activities consistent with the framework during a design day event requires significant effort and buy-in from all agencies and utilities involved.

Figure 55. Color-coded alert framework for New Jersey

Alert Level (Color)	Characteristics	BPU Actions (non-exhaustive)
 Normal (Green)	<ul style="list-style-type: none"> <li>Normal operating conditions</li> <li>Rules and emergency playbook can be reviewed and updated</li> </ul>	<ul style="list-style-type: none"> <li>Create necessary rules and regulations, as well as enforcement</li> <li>Participate in emergency drills and exercises</li> </ul>
 Elevated (Yellow)	<ul style="list-style-type: none"> <li>Potential Winter Design Day event (but no shortfall expected unless supply disruption takes place)</li> <li>System emergency protocols on standby</li> <li>Notifications sent to customers to encourage conservation</li> </ul>	<ul style="list-style-type: none"> <li>Coordinate communications to customers</li> </ul>
 Critical (Orange)	<ul style="list-style-type: none"> <li>Medium to high impact event (shortfall of up to 150 MDth/d) occurring</li> <li>Little to moderate damage reported</li> <li>System emergency protocols engaged</li> <li>All customers notified before, and direct load control implemented; customer communications during event</li> </ul>	<ul style="list-style-type: none"> <li>Obtain regular status updates from utilities on affected areas</li> <li>Direct load control may be implemented</li> <li>Coordinate communications to customers</li> </ul>
 Emergency (Red)	<ul style="list-style-type: none"> <li>High impact event occurring with significant (&gt;150 MDth/d) shortfall likely</li> <li>All customers notified before and during event</li> <li>System emergency protocols engaged</li> <li>Direct load control and load shed</li> <li>Outage maps created and regularly updated</li> </ul>	<ul style="list-style-type: none"> <li>Obtain regular status updates from utilities on affected areas</li> <li>Coordinate communications to customers</li> <li>If requested, coordinate utilities to provide qualified personnel for emergency operations</li> </ul>

#### 5.3.1.4 Examine whether new technology can help

Technological innovations can be employed to bolster resilience – in some jurisdictions, pressure sensors, which detect dramatic pressure drops and send signals to valves that immediately shut off flows for specific lines, can improve resilience and mitigate the impact of events such as ruptures or compressor outages. Utilities deploy drones and satellite imagery to assess damage in areas that are inaccessible to operations personnel (see text box).

### Improving gas distribution resilience through technology

As part of its Climate Change Adaptation and Resiliency operator safety plan, SoCalGas has undertaken several safety initiatives and deployed technological innovations as part of its tools. Its deployment of pressure sensors and satellite imagery, for example, has allowed for swift response to infrastructure damage. During the recent wildfire and mudslide events in California, SoCalGas used meter response and meter throughput data to identify possible impacted areas. Specifically, pressure sensors allowed for the immediate shut off of flows for specific points in the system once dramatic drops in pressure were detected.

Satellite imagery was used in the immediate aftermath of various extreme weather events such as mudslides and wildfires, when restrictions from the Federal Aviation Administration prohibited flights from third parties to avoid conflict with first responders' rescue efforts.

Sources: Southern California Gas, "Natural Gas System Operator Safety Plan: Chapter 8," February 22, 2018; ICF. *Case Studies of Natural Gas Sector Resilience. Prepared for Southern California Gas.* October 2019.

#### 5.3.1.5 Identify and exempt critical gas supply infrastructure from rolling blackouts

In recognition of the interconnection of the gas and electric systems, rolling electrical blackouts inadvertently make things worse, because a rolling blackout could hamper gas production. For instance, instrumentation that is powered by electricity, compression, pumps, and processing equipment are all used to move gas from producers to customers. Even a "brief or temporary loss of electric power can put a gas production, processing, compression, or storage facility out of service for long periods of time."<sup>202</sup>

Thus, the BPU should work with other regulators and stakeholders in PJM to establish rules or operating procedures that enable gas supply functions to continue operation and be shielded from the effects of a blackout. Interstate pipelines and storage providers could identify portions of their system that are critical to maintaining ongoing services and provide a list of facilities to the BPU and other policymakers for inclusion in a rulemaking.




#### 5.3.2 Withstanding: Implement the tools and plan

In this section, LEI presents an implementation Playbook for coping with an Orange Alert (a 1-in-90 Design Day, or a shortfall of up to 150 MDth/d) and a Red Alert (the Perfect Storm of a Winter Design Day combined with a large outage, resulting in a shortfall of 525 MDth/d).

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<sup>202</sup> FERC/NERC staff. *Report on Outages and Curtailments During the Southwest Cold Weather Event of February 1-5, 2011. Causes and Recommendations.* August 2011. P.223.

Figure 56. Authorities' responses to three shortfall scenarios

Summary	Winter Design Day (no shortfall, but potential for a shortfall if supply is disrupted)	1-in-90 Design Day (shortfall of up to 150 MDth/d)	Perfect Storm (shortfall of >500 MDth/d)
Alert Level	 Elevated (Yellow)	 Critical (Orange)	 Emergency (Red)
Responsible agencies	<ul style="list-style-type: none"> <li>▪ BPU</li> </ul>	<ul style="list-style-type: none"> <li>▪ BPU</li> <li>▪ NJ Office of Emergency Management</li> </ul>	<ul style="list-style-type: none"> <li>▪ NJ Office of Emergency Management</li> <li>▪ NJ Governor's Office</li> <li>▪ NJ State Police</li> </ul>
Communication frequency	<ul style="list-style-type: none"> <li>▪ Every 12 hours until design day conditions subside</li> </ul>	<ul style="list-style-type: none"> <li>▪ Every 3-6 hours until design day conditions subside</li> </ul>	<ul style="list-style-type: none"> <li>▪ Every hour</li> </ul>
Potential mitigation actions	<ul style="list-style-type: none"> <li>▪ Rely on NPA <i>if the state is on track to achieve adequate levels</i></li> </ul>	<ul style="list-style-type: none"> <li>▪ Direct control DR of up to 2 degrees on average</li> <li>▪ Public conservation appeals</li> <li>▪ Localized or broad curtailment if necessary</li> </ul>	<ul style="list-style-type: none"> <li>▪ Direct control DR of 5-10 degrees on average</li> <li>▪ Public conservation appeals</li> <li>▪ Localized or broad curtailment if necessary</li> </ul>

In the shortfall scenarios, the worse the potential shortfall, the more agencies should be involved (see Figure 56). Likewise, the frequency of communication to the public and customers should be increased the worse the emergency; and the potential mitigation actions will be more draconian the worse the emergency. Figure 57 lays out a summary of the response protocols described in the following subsections.

Figure 57. Playbook plan for critical and emergency events

Response timeline	Winter Design Day	1-in-90 Design Day	Perfect Storm
Alert Level	Elevated (Yellow)	Critical (Orange)	Emergency (Red)
- Two days prior event	<ul style="list-style-type: none"> <li>Initial notification to customers to conserve gas</li> <li>Activate RIOC</li> <li>Engage playbook</li> </ul>	<ul style="list-style-type: none"> <li>Initial notification and information to all customers that direct load control of up to 2 degrees might be implemented</li> <li>Activate RIOC</li> <li>Engage playbook</li> <li>Contact other agencies</li> </ul>	<ul style="list-style-type: none"> <li>Initial notification and information to all customers that direct load control of up to 10 degrees might be implemented</li> <li>Activate RIOC</li> <li>Engage playbook</li> </ul>
Event begins	<ul style="list-style-type: none"> <li>No event unless a supply disruption occurs in addition to Design Day demand – if supply disruption occurs, the system goes on Orange Alert (of disruption &lt; 150 MDth/d) or Red Alert (if &gt;150 MDth/d)</li> </ul>	<ul style="list-style-type: none"> <li>Notify customers of key information and resource identification</li> <li>Implement direct load control</li> <li>Implement curtailment if necessary</li> </ul>	<ul style="list-style-type: none"> <li>Contact other agencies</li> <li>Notify customers of key information and resource identification</li> <li>Notify customers of need for up to 10 degrees of direct load control</li> <li>Identify and secure supplies for critical infrastructure</li> <li>Implement direct load control and curtailment if necessary</li> </ul>
Several hours into event	<ul style="list-style-type: none"> <li>Communication every 12 hours until Winter Design Day conditions subside</li> </ul>	<ul style="list-style-type: none"> <li>Regular communications with customers (every 3-6 hours) until conditions subside</li> <li>Mapping outages</li> </ul>	<ul style="list-style-type: none"> <li>Regular communications with customers (every hour)</li> <li>Mapping outages</li> <li>Establish support centers and shelters</li> </ul>
+ Two days after event	<ul style="list-style-type: none"> <li>Thank customers on voluntary and direct load control if implemented</li> </ul>	<ul style="list-style-type: none"> <li>Dispatch crews to begin service restoration</li> <li>Forecast outage length</li> <li>Support impacted regions and customers</li> </ul>	<ul style="list-style-type: none"> <li>Status update and situational awareness with pipeline operators</li> <li>Forecast outage length</li> <li>Support impacted regions and customers</li> </ul>
+ 14 days after event	<ul style="list-style-type: none"> <li>Thank customers and provide bill credits for direct load control</li> <li>Assess impact of direct control turn-down and voluntary DR to refine the program further</li> </ul>	<ul style="list-style-type: none"> <li>Relighting ongoing or completed</li> <li>Thank customers and bill credits for direct load control</li> <li>Economic impact assessment and recovery plan ongoing</li> <li>Assess impact of direct control turn-down and voluntary DR to refine the program further</li> </ul>	<ul style="list-style-type: none"> <li>Ongoing support for impacted customers</li> <li>Thank customers and bill credits for direct load control</li> <li>Repair work ongoing</li> <li>Distribution of federal support if needed</li> <li>Assess impact of direct control turn-down and voluntary DR to refine the program further</li> </ul>

### 5.3.2.1 Playbook for a 1-in-90 Design Day

A 1-in-90 Design Day, if it occurred in 2030, would leave the system short 153 MDth/d, as discussed in Section 4. Under these conditions, the BPU would issue an Orange Alert level for natural gas customers:

1. **Two days prior to the event:** as weather forecasts point to the likelihood of a 1-in-90 event, the BPU will coordinate with the ROIC and other agencies to notify customers of the coming event. Notifications will be sent out to all customers via widely available channels, including radio, text messages, and social media platforms to ensure maximum reach.

Messaging in the notifications to customers will include, at a minimum, supplemental information on emergency preparation tips, nearby support services, and reminders of automated thermostat reduction, where applicable. A 1-in-90 weather event (71.3 HDD, as compared to the 66.4 HDD assumed for a Winter Design Day) would lead to a shortfall of 153 MDth/d. This implies the need to turn thermostats down by an average of about two degrees for every customer on the system (each HDD accounts for about 76.6 MDth/d). Customers will be told that automatic thermostat reductions of about 2 degrees will likely be implemented.

2. **1-in-90 weather begins:** as temperatures drop, the BPU will coordinate messages to customers and provide a timetable of when customers may expect further information. As consumption rises, the BPU and the GDCs will begin to implement demand mitigation measures such as peak shaving via automated thermostat controls. The GDCs will begin to regularly update the BPU and other ROIC agencies on operating conditions on their systems, including communications received from interstate pipelines such as operational flow orders (“OFOs”).<sup>203</sup>
3. **Several hours into the cold weather:** at this time, regular notifications are sent to customers every 3-6 hours. As peak shavings are implemented, customers are made aware of the extent to which their thermostats have been altered and thanked for their contribution to avoiding disaster.

If curtailment of firm demand is needed, the GDCs will specify the regions impacted, and an outage map made available on the utility, BPU, and ROIC websites. Customers impacted by curtailment will be directed to available support services and centers that have been established.

4. **Two days after the event:** once the cold snap has passed, notifications may be reduced to once or twice per day. GDCs will begin to return to regular operations and repair crews and technicians will be dispatched to begin repairs and re-lighting as needed. Outage maps and on-demand data and support information will remain posted on the BPU and GDC websites.
5. **Two weeks after the event:** Once service restoration and relighting are completed, the GDCs and the BPU will begin to evaluate the economic impact. These assessments will be undertaken under regular BPU disaster recovery mechanisms and procedures. For customers whose thermostats were automatically turned down, bills will include a pre-determined dollar amount credit and “thank you for helping us weather the storm” or similar acknowledgment. Data collected from the event will help fine-tune and adapt the demand response and direct load control programs.

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<sup>203</sup> FERC regulations require interstate pipelines to issue communications and directives to shippers whenever their operations are strained. These include critical notices, which occur when the pipeline believes integrity of the system is threatened and include associated reasons and actions for shippers. Operational Flow Orders (“OFOs”) are notices to shippers on actions to take when the pipeline believes conditions are threatened and entail requests that shippers balance the supply with their usage within a specified tolerance band. (Source: Code of Federal Regulations. §284.12 *Standards for pipeline business operations and communications*. Order 587, 61 FR 39068, July 26, 1996.)

These actions are in addition to usual GDC responses such as the use of gas from storage, peaking supplies, and curtailment of interruptible customers, as is the usual practice.

### 5.3.2.2 Playbook for a Perfect Storm

LEI's Perfect Storm posits Winter Peak Design Day (66.4 HDD) demand combined with a major supply disruption. Under these conditions, the supply shortfall is about 525 MDth/d, triggering a Red Alert:

1. **Two days prior to the event:** forecasts and communications will announce a Yellow alert to reflect the high level of demand expected.
2. **Supply disruption reported:** a supply disruption is reported by the pipeline operator in accordance with FERC notification protocols.<sup>204</sup> GDCs will immediately report the disruption to the BPU and ROIC agencies. The system will go to Red Alert. Firm customers will be notified that GDCs may begin to turn down direct-control thermostats by about 7 degrees (on average) if the shortfall is expected to be 525 MDth/d, but depending on the actual expected shortfall, the turn-down could be greater, up to 10 degrees, for example. Firm commercial and industrial customers might be curtailed. If further demand reduction is needed, Governor's orders may be issued. If the emergency does not also involve electric power, customers may be advised to augment heat using portable electric space heaters.

If the supply outage includes loss of natural gas production, it may impact electric plants. If the electric system operator implements rolling blackouts, gas supply, storage, and transmission infrastructure, which will have already been identified as critical, should not be "rolled."

3. **Several hours into weather conditions and outage:** at this time, hourly notifications are sent to customers, and curtailment of firm demand begins. GDCs will specify regions impacted, and support services and facilities will be opened as coordinated by the ROIC. Separately, an appeal for conservation will be made by the Governor's Office as part of the communications.
4. **Two days after the event:** demand may return to normal winter demand, but the pipeline outage may still be underway (or vice versa). Repair crews and technicians will be dispatched to begin operations in affected areas. Similarly, outage maps and support information will be uploaded on the BPU and GDC websites.

If necessary, support centers will remain open until repairs are complete, and any state and federal support will be distributed and coordinated by the ROIC.

5. **One week+ after the event:** the pipeline operator will undertake repairs at the outage site and engage with the GDCs to provide a timeline for resumption of regular service. GDCs and the BPU may assess the economic impact, consistent with existing mechanisms and

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<sup>204</sup> The pipeline may declare an OFO or force majeure event. The latter is a suspension of its supply obligations due to an unplanned or unanticipated event, or circumstances not within the control of the operator. (Source: Code of Federal Regulations. §284.12 *Standards for pipeline business operations and communications*. Order 587, 61 FR 39068, July 26, 1996.)



procedures. Customers who had their thermostats turned down will receive a pre-determined bill credit and will be thanked for playing their part in averting disaster. Data collected from the event will help fine-tune and adapt the demand response programs.

**5.3.3 Adaptation: Expect and plan for more frequent and more disruptive events**

One of the mistakes made in Texas in 2011, which made the 2021 disaster worse than it might otherwise have been, was that many thought the 2011 storm was a one-off event that was unlikely to happen again. They were wrong.

Over the past two decades, NOAA’s National Centers for Environmental Information (“NCEI”) data shows an increase in extreme weather events. Specifically, the US has sustained 285 weather and climate disasters since 1980 where overall damages/costs reached or exceeded \$1 billion, or an average of 7 events per year.<sup>205</sup> The data suggests that the frequency of these events is increasing over time – the year 2020 involved 22 separate events, which was an annual record and exceeded the previous record of 16. Notably, the previous record of 16 events occurred within the past decade, i.e., 2011 and 2016.<sup>206</sup> The trend of these high-cost disasters has been increasing (see Figure 58) and is driven by a combination of climate change, increased vulnerability (i.e., how much damage a hazard causes at a location), and exposure (i.e., the greater number of assets at risk).

**Figure 58. Increased number of costly disasters in the US**

Time period	Average annual costs	Average events per year
1980-2020	\$45.7 billion	7.0
2011-2020	\$89.0 billion	13.5
2016-2020	\$121.3 billion	16.2

Source: NOAA National Centers for Environmental Information (NCEI). *U.S. Billion-Dollar Weather and Climate Disasters*. 2021.

In New Jersey, over the same period (1980 to 2020), there have been 50 events with at least \$1 billion in damage, or about 1.2 such events per year, and at an estimated total cost of between \$20 to \$50 billion. The period between 2011 and 2020 witnessed 22 events, and the five-year period

<sup>205</sup> Smith, A. 2020 *U.S. billion-dollar weather and climate disasters in historical context*. NOAA. January 2021. <<https://www.climate.gov/news-features/blogs/beyond-data/2020-us-billion-dollar-weather-and-climate-disasters-historical>>

<sup>206</sup> Ibid.

between 2016 and 2020 saw 12 events – hence the national trend of increasing frequency and severity impacts New Jersey as well (see Figure 59).

**Figure 59. Trends in billion-dollar disasters in New Jersey (1980-2020)**

Time period	Number of disasters	Average events per year	Estimated costs
1980-2020	50	1.2	\$20-50 billion
2011-2020	22	2.2	\$20-50 billion
2016-2020	12	2.4	\$1.0-\$2.0 billion

Source: NOAA National Centers for Environmental Information (NCEI). *U.S. Billion-Dollar Weather and Climate Disasters*. 2021.

Data from NCEI only includes disasters with damage over \$1 billion, which, although accounting for over 80% of all damage during this time period, does not account for all events. This suggests that the data is likely conservative, and certain events at the state level may have been excluded. However, the trends are evident, and climate researchers are arriving at a consensus that extreme weather events are on the rise and likely to remain so going forward.<sup>207,208</sup>

<sup>207</sup> Cohen, Judah, Karl Pfeiffer, and Jennifer A. Francis. "Warm Arctic episodes linked with increased frequency of extreme winter weather in the United States." *Nature communications* 9.1 (2018): 1-12.

<sup>208</sup> Coronese, Matteo, et al. "Evidence for sharp increase in the economic damages of extreme natural disasters." *Proceedings of the National Academy of Sciences* 116.43 (2019): 21450-21455.

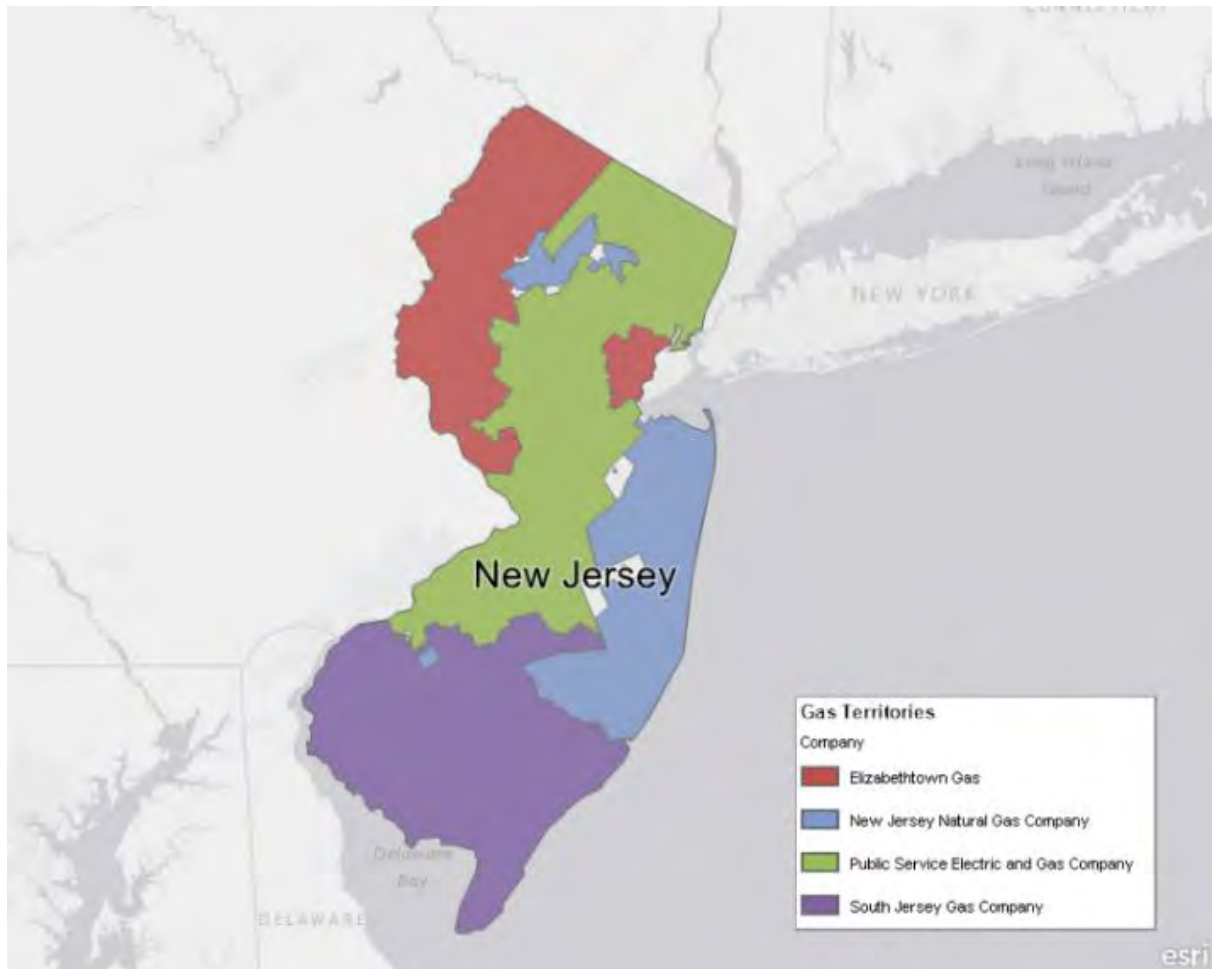
## 6 Appendix 1: Supplying natural gas to New Jersey

As discussed in Section 2 previously, New Jersey relies on natural gas supplies from outside the state. Each of the four GDCs has specific points of interconnection to large gas pipelines. This Appendix provides details of which pipelines serve which GDC and the capacity available to each GDC.

### 6.2 Interstate pipelines serve the New Jersey GDCs

Four GDCs in New Jersey are responsible for meeting the majority of customer demand in the state: ETG, NJNG, PSE&G, and SJG (see Figure 60).

Figure 60. New Jersey GDC service territories

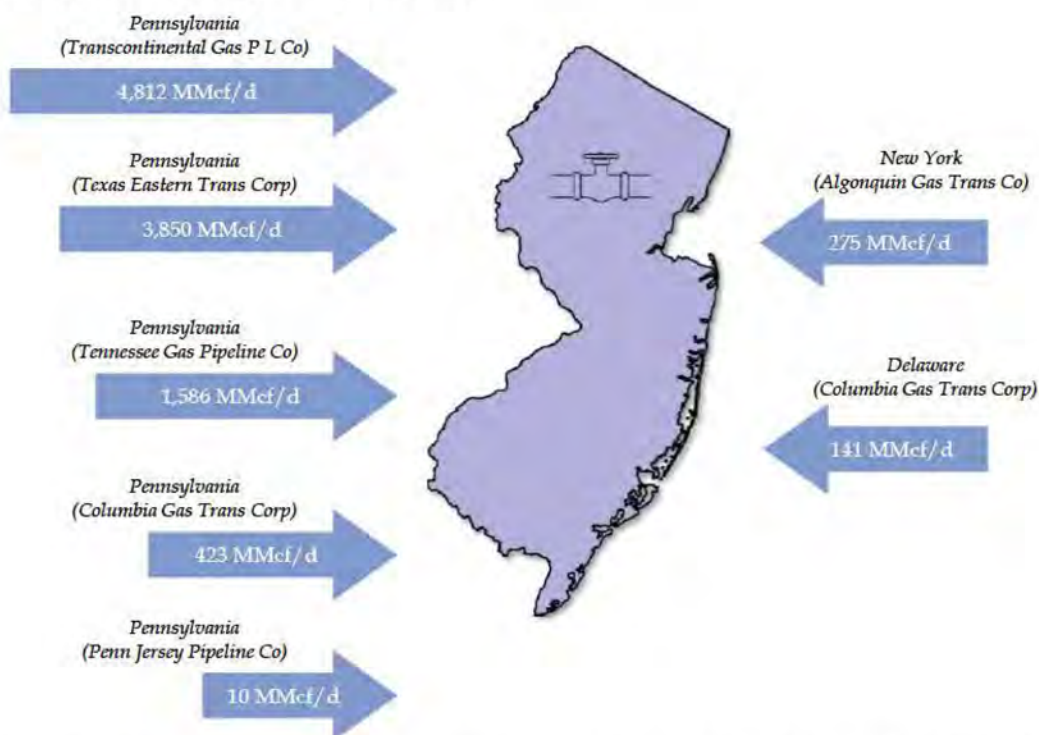


Source: Third-party commercial database.

To meet their customer demand, the utilities rely on interstate pipelines (see Figure 61). The two largest, the Transcontinental Pipeline (“Transco”) and Texas Eastern Transmission (“Tetco”), account for over three quarters of total capacity flowing into, and also out of, the state. The Tennessee Gas Pipeline (“TGP”) is the third-largest pipeline serving the GDCs. Three smaller

pipelines (Algonquin, Columbia Gas Transmission from Delaware, and Penn Jersey Pipeline) also transport gas into New Jersey.

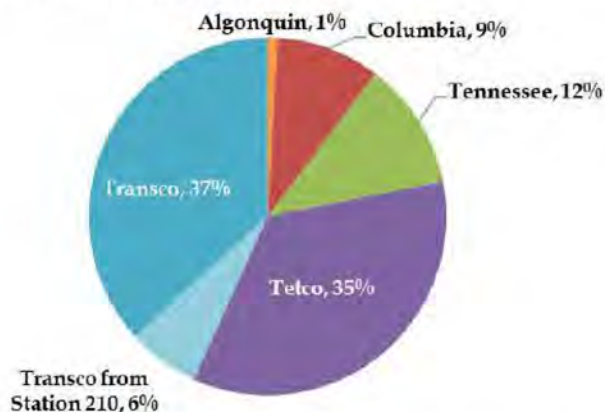
**Figure 61. Pipeline capacity into New Jersey**



Source: Energy Information Administration. *Natural Gas data: State to State Capacity*. Release date: January 2021.

Contracts on Transco and Tetco account respectively for 43% and 35% of GDC FT contracts as of Q4 2020 (see Figure 62). Transco’s Station 210 represents a pooling point for Transco’s supply into New Jersey and is broken out as a separate segment (see text box).

**Figure 62. Share of GDC FT contracts by pipeline, Q4 2020**



Note: ‘Transco from Station 210’ breaks out Transco FT contracts where Station 210 is listed as the receipt point.

Source: S&P Global Market Intelligence. *Index of Customers*. Q4 2020.

### Transco Station 210

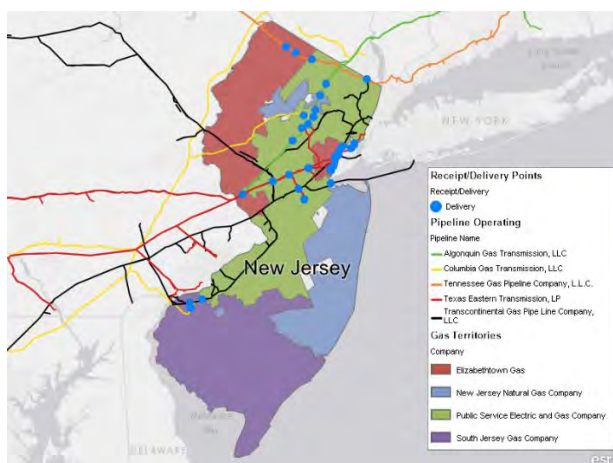
Pooling points on an interstate pipeline system are points at which gas is aggregated from many receipt points to serve several contracts, without tying a specific receipt point to a specific contract. In New Jersey, Transco's Zone 6 pooling point is known as Station 210. Station 210 receives natural gas from the Marcellus Shale that is transported east from the Leidy hub. Several Transco contracts have a portion of their paths pass through New Jersey deliver or receive gas at this pooling point - there is no local supply or production associated with Station 210. Currently, there is more contracted firm transportation to receive gas than contracts to deliver at Station 210, according to Index of Contracts data.

Sources: EIA; Interstate Natural Gas Association of America; S&P Global Market Intelligence. *Index of Customers*. Q4 2020.

### 6.3 Operating capacity at city gate stations

A city gate is a custody transfer point or measuring station at which a local gas distribution utility receives gas from an interstate pipeline or transmission system.<sup>209</sup> LEI undertook a systematic review of all delivery points in New Jersey associated with all interstate gas pipelines that pass through the state. We utilized a commercial database for our review, and wherever possible, corroborated our findings with publicly available utility filings and reports. LEI identified a total of 44 city gates associated with pipelines in New Jersey, of which 40 were specific to the four GDCs (see Figure 63 and Figure 64). Delivery capacity is not necessarily additive along a pipeline, it simply identifies the maximum volume that can be delivered at a given point.

Figure 63. Overview of pipeline delivery points in New Jersey



Source: Third-party commercial database.

<sup>209</sup> US Energy Information Administration. *Natural Gas: Definitions, Sources and Explanatory Notes*. <<https://www.eia.gov/naturalgas/data.php>>

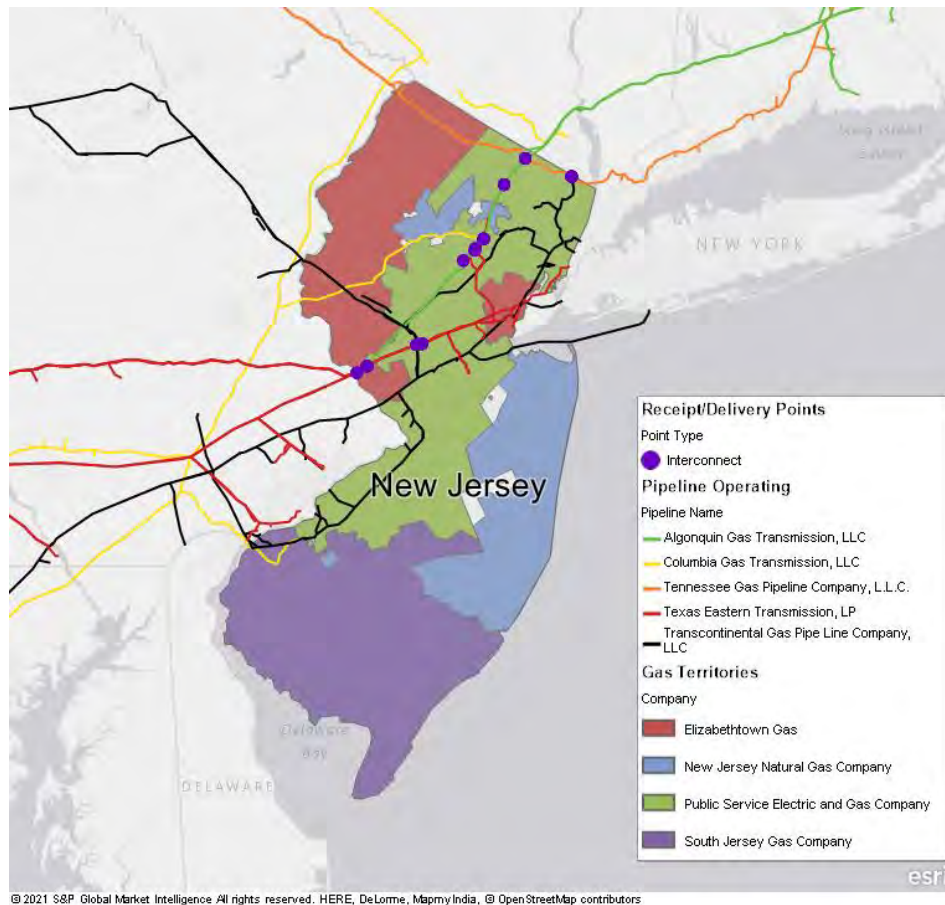
Figure 64. Delivery capacity at New Jersey GDC city gates and other points

Utility	Pipeline	Delivery point name	Operational capacity (MDth/day)
New Jersey Natural Gas	Transco	New Jersey Natural MP 1790.84	30.8
		New Jersey Natural - Hanover, NJ	50.8
	Texas Eastern	New Jersey Natural - Jamesburg, NJ	339.6
		New Jersey Natural - Montville, NJ	54.1
		New Jersey Natural - Freehold, NJ	658.8
	Columbia Gas Transmission	New Jersey Natural	80.0
	Tennessee Gas Pipeline	NJ Natgs/TGP New Clinton Road Nj Be	138.4
Algonquin Gas Transmission	Partroy (Morris, NJ)	18.0	
Elizabethtown Gas	Transco	Elizabethtown MP 1807.85	264.3
	Texas Eastern	Elizabethtown Gas Company - Elizabeth, NJ	149.3
		Elizabethtown Gas Company - Linden, NJ	66.9
		Elizabethtown Gas Company - Perth Amboy, NJ	64.5
		Elizabethtown Gas Company - Ringoes, NJ	26.0
		Elizabethtown Gas Company - Union Co., NJ	74.9
	Columbia Gas Transmission	Elizabethtown-22	180.8
		Elizabethtown-23	22.5
	Tennessee Gas Pipeline	Eliztown/Tgp Vernon Nj Sussex	3.3
		Eliztown/Tgp Sussex Nj Sussex	14.5
South Jersey Gas	Transco	S Jersey Gas Co MP 46.58	371.1
	Columbia Gas Transmission	South Jersey Gas Co	209.0
PSE&G	Transco	Public Service E&G MP 1809.25	1,585.9
	Texas Eastern	MR 128 Upgrade (Public Service - Linden, NJ) Del	574.8
		PSEG-Bayonne, Hudson Co., NJ	7.5
		Public Service - Bound Brook, NJ	41.40
		Public Service - Central Works, NJ	147.7
		Public Service - Hanover, NJ	173.3
		Public Service - Hillsborough, NJ	96.3
		Public Service - Jamesburg - Middlesex Co., NJ	84.1
		Public Service - Linden, NJ	821.0
		Public Service - Sewaren, NJ	145.1
		Public Service - South Plainfield, NJ	91.0
	Public Service - Wanaque, NJ	207.1	
	Public Service - Woodbridge, NJ	156.8	
	Columbia Gas Transmission	Parsippany	36.0
		West Deptford/PSEG	58.1
	Tennessee Gas Pipeline	PSEG/TPG Ramsey NJ Bergen	173.4
		PSEG/TGP West Milford NJ Passaic	16.9
PSEG/TGP Ringwood NJ Passaic		29.7	
Algonquin Gas Transmission	Bernards (Somerset, NJ)	75.0	
	Morris (Morris, NJ)	36.5	
Other	Transco	Orange Rockland MP 19.16	434.8
	Texas Eastern	Amerada Hess (Port Reading Interconnect) Middlesex Co., NJ	60.8
		Coned-Manhattan Delivery	1,189.7
		Head Of Freehold Lateral - Mainline	2,234.3

Source: Third party commercial database.

Multiple interconnections between the five pipelines through New Jersey serve as points of redundancy (see Figure 65).

**Figure 65. Interconnection points among interstate gas pipelines in New Jersey**



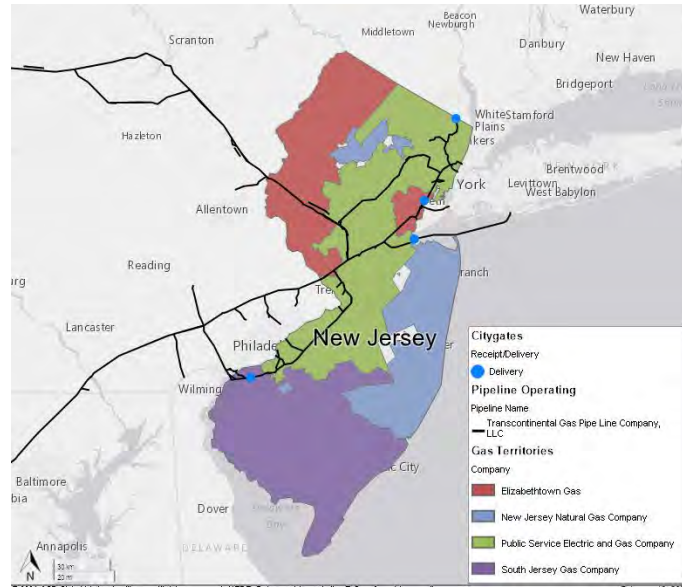
Source: Third-party commercial database.

### 6.3.1 Transco is the largest supplier on the system

The Transco pipeline crosses all four major GDCs in New Jersey as part of its Zone 6 segment (see Figure 66). Transco delivery points are associated with all the major New Jersey GDCs (NJNG, ETG, PSE&G, and SJG), while the fourth serves a New York GDC. The maximum capacity of the NJNG delivery points is 31 MDth/d.<sup>210</sup> The maximum capacity of the ETG delivery points is approximately 264 MDth/d, while the maximum capacity of the SJG delivery point is 371 MDth/d (see Figure 64 shown previously and Figure 66).

<sup>210</sup> Maximum capacity for a delivery point refers to the largest amount of volume that the delivery point can receive on any given day.

Figure 66. Transco pipeline delivery points in New Jersey

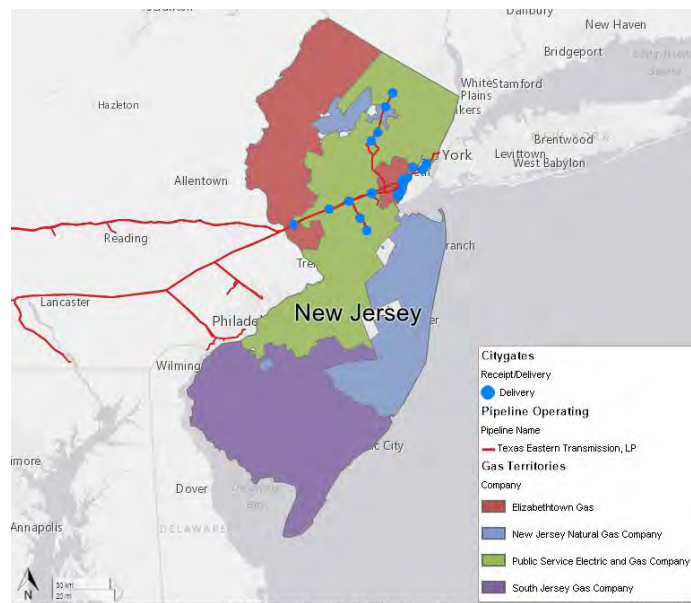


Source: Third-party commercial database.

### 6.3.2 Tetco's pipeline contains several delivery points for each utility

There are 24 delivery points associated with Tetco's Zone 3 segment serving New Jersey, with delivery points in all the GDC service territories. Four are associated with NJNG (see Figure 64 shown previously and Figure 67), five are associated with ETG, and 12 are associated with PSE&G. The remaining three delivery points are not directly associated with any of the New Jersey GDCs.

Figure 67. Tetco pipeline delivery points in New Jersey



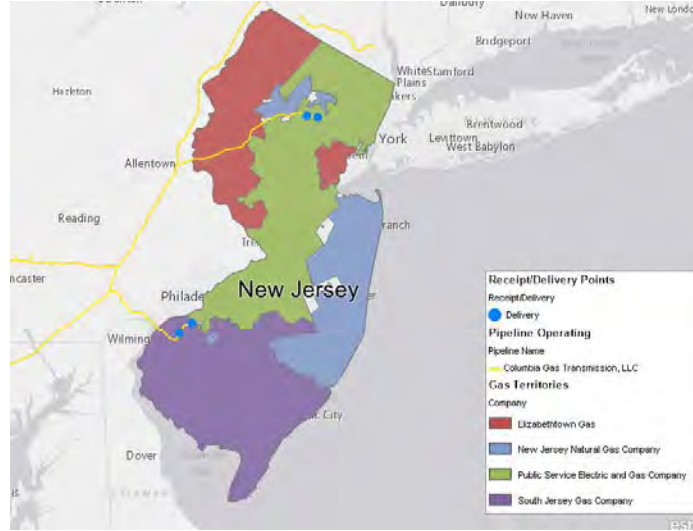
Source: Third party commercial database.



### 6.3.3 Columbia Gas has fewer delivery points

The Columbia Gas pipeline only has four delivery points in New Jersey (see Figure 64 shown previously, and Figure 68).

**Figure 68. Columbia Gas pipeline delivery points in New Jersey**

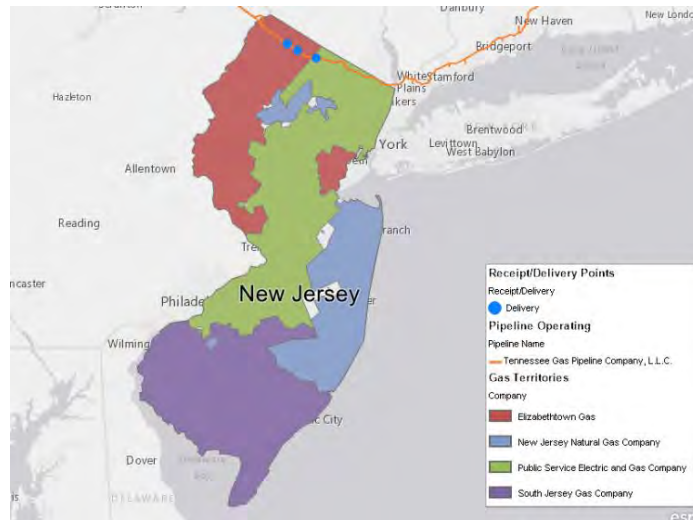


Source: Third-party commercial database

### 6.3.4 Tennessee Gas Pipeline serves northern New Jersey

TGP passes through only two GDCs (ETG and PSE&G) in northern New Jersey near the New York border. There are three delivery points along the pipeline. The NJNG delivery point (which appears to lie in PSE&G's service territory in Figure 69) has a maximum capacity of 138 MDth/d (see Figure 64 shown previously).

**Figure 69. TGP pipeline delivery points in New Jersey**



Source: Third party commercial database.

### 6.3.5 Algonquin Gas serves PSE&G

The Algonquin Gas pipeline is mainly located within PSE&G's service area. There are three delivery points in New Jersey along the pipeline (see Figure 70).

**Figure 70. Algonquin Gas pipeline delivery points in New Jersey**



Source: Third-party commercial database.

## 6.4 Upstream incidents and accidents can potentially cause bottlenecks

Pipelines serving New Jersey have had accidents and operational issues in the past, as described in this section. New Jersey consumers have been lucky in two respects: first because these did not lead to loss of life; and second, the major problems did not occur in the winter, when demand is high. But they easily could have led to more serious consequences, and thus Section 5 (Best Practices and Playbook) focuses on coping with large outages.

Reliability data for the pipelines can identify operational issues that can lead to bottlenecks. While there were no incidents that resulted in death or serious injury between 2001 and 2020 in New Jersey,<sup>211</sup> there were less serious events that could have impacted delivery or resulted in reduced capacity. The Pipeline and Hazardous Materials Safety Administration (“PHMSA”) identified four significant incidents associated with interstate pipelines in the state from 2005 to 2019 (see Figure 71). All had different identified causes; three were associated with Transco, and the other with TGP. There were no price spikes to indicate supply shortages on those days, probably because the events did not happen in the dead of winter when demand is high.<sup>212</sup> Upstream of

<sup>211</sup> A serious incident is defined as a safety incident that includes a fatality or injury requiring in-patient hospitalization while a significant incident includes serious incidences as well as highly volatile liquid releases of 5 barrels or more or other liquid releases of 50 barrels or more, or \$50,000 or more in total costs (measured in 1984 dollars). (Source: US DOT Pipelines and Hazardous Materials Safety Administration. *Pipeline Incident 20 Year Trends*. Last updated: February 2021.)

<sup>212</sup> US DOT Pipeline and Hazardous Materials Safety Administration. *Gas Transmission Onshore Significant Incidents per 1,000 Miles*. Data as of February 2021.

New Jersey, two *force majeure* incidents occurred in the past ten years, one on Transco and one on Tetco. PHMSA attributed these to high levels of corrosion that went undetected, ultimately leading to ruptures and outages (see Figure 72). The events occurred during the months of April and June when gas demand is seasonally low, so the outages did not result in gas supply shortages to customers.

**Figure 71. Significant pipeline incidents in New Jersey**

Operator Name	Year	Date	Incident County	Portion of system affected	Cause of incident	Description
TGP	2017	8/14/2017	Sussex	Onshore Compressor Station Equipment And Piping	Equipment Failure	Threaded Connection/Coupling Failure
Transco	2012	4/2/2012	Hudson	Onshore Pipeline, Including Valve Sites	Other Outside Force Damage	Previous Mechanical Damage
	2014	3/10/2014	Bergen	Onshore Regulator/ Metering Station Equipment And Piping	Material Failure Of Pipe Or Weld	Construction, Installation Or Fabrication-related
	2018	9/20/2018	Middlesex	Onshore Compressor Station Equipment And Piping	Incorrect Operation	Incorrect Valve Position

Source: US DOT Pipeline and Hazardous Materials Safety Administration. *Gas Transmission Onshore Significant Incidents per 1,000 Miles*. Data as of February 2021.

**Figure 72. Significant pipeline events upstream of New Jersey**

Pipeline	Date	Incident description
Transco	June 2015	<ul style="list-style-type: none"> <li>▪ Transco declared force majeure after a rupture shut flows on the Leidy Line B near Unityville, Pennsylvania</li> <li>▪ PHMSA identified the cause as corrosion along the line resulting in “cracking of the pipe”.</li> <li>▪ Operation on the Leidy system at reduced pressure was implemented and Transco noted that the lower pressure might limit the availability of non-firm capacity and could impact firm services during periods of high-capacity utilization</li> <li>▪ Transco was able to reroute deliveries through its Lines A and C</li> </ul>
Texas Eastern	April 2016	<ul style="list-style-type: none"> <li>▪ Pipeline rupture on the Texas Eastern pipeline next to Delmont, Pennsylvania resulted in an explosion and a repair time of ~6 months</li> <li>▪ The cause of the rupture was identified as high levels of corrosion due to a “failed tape coating” that were not detected</li> <li>▪ Deliveries were not affected at the time, as the rupture occurred whereby Texas Eastern has four lines running in parallel, and had a utilization of 50% at the time of rupture</li> </ul>

Sources: Spectra Energy. *Technical Root Cause Analysis of Delmont Line 27 Failure*. Prepared by DNV GL. October 2016; US Pipeline and Hazardous Materials Safety Administration. *Failure Investigation Report – Williams Partners L.P./Transco 24” Leidy Line B Failure, Unityville, PA*. January 2016.

## 7 Appendix 2: Lessons learned from recent disasters

### 7.1 Texas response to 2011: What not to do

In February 2011, extreme weather, including heavy snow, ice, freezing rain, and frigid wind hit Texas, in a storm referred to as the Groundhog's Day Blizzard.<sup>213</sup> A combination of record winter load and multiple forced outages, failures to start electric generating plants, and generating plant derates led the electric system operator, ERCOT, to issue an Energy Emergency Alert Level 3 ("EEA-3")<sup>214</sup> and implement controlled load shedding of 4,000 MW on February 2<sup>nd</sup>. On February 3<sup>rd</sup>, transmission constraints and further generation outages led to load shed of another 180,000 customers. Nearly 4 million electric customers were affected over the course of the event.<sup>215</sup>

Natural gas customers were also impacted, with extensive curtailments of service during the extreme weather event, and long outages owing to the need to manually relight gas pilot lights at each customer's location. FERC reported that over 50,000 customers in Arizona, New Mexico, and Texas experienced interruptions of gas service. EIA data shows a substantial decline in natural gas production during the week of the outage, owing to well freeze-offs and other temperature-related well failures, processing plant shutdowns, electric power outages, and pipeline operational issues. Natural gas production in the US fell from about 62 Bcf/d to less than 57 Bcf/d.<sup>216</sup> According to the FERC investigation, of the 5.5 Bcf/d decline experienced, 4.4 Bcf/d occurred in production basins in Texas and New Mexico.<sup>217</sup>

Following this event, inquiries were conducted by state and federal officials, reaching several conclusions, including:

- **Insufficiency of black start generation units:** FERC/NERC's investigation suggested that in ERCOT's case, nearly half of its black start units were either on the scheduled outage at the time of the event or failed during the event itself.<sup>218</sup>
- **Lack of adequate winterization:** FERC staff reported that 67% of generator failures (by MWh) were due directly to weather-related causes, including frozen sensing lines, frozen equipment, frozen water lines, frozen valves, blade icing, and low temperature cutoff limits. Another 12% were indirectly attributable to the cold, including natural gas curtailments to gas-fired generators and difficulties in fuel switching. While generators

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<sup>213</sup> NOAA National Climatic Data Center (NCDC), State of the Climate: Global Hazards for February 2011. March 2011.

<sup>214</sup> According to its operating guide, an EEA-3 is declared by ERCOT when operating reserves can no longer be maintained above 1,375 MW. At this point, ERCOT may instruct transmission companies to institute rotating outages. (Source: ERCOT. ERCOT's use of Energy Emergency Alerts. March 2019).

<sup>215</sup> FERC/NERC staff. Report on Outages and Curtailments During the Southwest Cold Weather Event of February 1-5, 2011. Causes and Recommendations. August 2011.

<sup>216</sup> US Energy Information Administration. Today in Energy. Frigid weather reduces US natural gas supply. February 23, 2011.

<sup>217</sup> FERC/NERC staff. Report on Outages and Curtailments During the Southwest Cold Weather Event of February 1-5, 2011. Causes and Recommendations. August 2011. P.122.

<sup>218</sup> Ibid.

reported having winterization procedures prior to the storm, they proved inadequate. FERC/NERC concluded that “many generators failed to adequately apply and institutionalize knowledge and recommendations from previous severe winter weather events, especially as to winterization of generation and plant auxiliary equipment.”<sup>219</sup>

- **Interdependence of gas and electricity systems:** about a quarter of the natural gas shortfalls in the Permian and Fort Worth Basins were attributed to rolling blackouts or customer curtailments that affected producers.<sup>220</sup>

The PUCT, the entity responsible for issuing operating procedures, had previously issued winterization recommendations following a similar storm in 1989, over two decades prior to the 2011 storm. Like those issued after the 2011 storm, these recommendations were voluntary and lapsed over time – FERC investigation found that units that failed in 1989 also failed in 2011.<sup>221</sup>

Following the Groundhog’s Day Storm, the PUCT instituted §25.53 “Electric Service Emergency Operations Plans” in its rules which, among other provisions, required market participants (i.e., generators on the ERCOT system) to have emergency operations plans that should be filed with the regulator.<sup>222</sup> ERCOT has observed that although it regularly spot-checks generators, there are no penalties for entities not in compliance with their plans – plant personnel are left with a recommendation(s) based on lessons learned or best practices observed, and senior management are emailed results.<sup>223</sup>

In spite of these putative efforts, nearly a decade later, the polar vortex of February 2021 took a huge portion of electric generation in Texas offline, especially gas-fired generation.<sup>224</sup> Customers lost power for days on end; water supplies were contaminated, and people froze to death. All this happened despite the policies developed in response to the Groundhog Day Storm.

## 7.2 PJM’s response to the 2014 polar vortex proved effective in 2018

In early January 2014, the northeast region of the United States was severely affected by a polar vortex. January 7, 2014 represented the coldest day in the northeast with 58 HDD in New Jersey and 63 HDD in Pennsylvania.<sup>225</sup> Demand for gas for heating surged and several major pipelines supplying the northeast issued critical notices and operational flow orders (“OFOs”) to prevent

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<sup>219</sup> Ibid. P.203.

<sup>220</sup> FERC/NERC staff. P. 18.

<sup>221</sup> FERC/NERC staff. P. 18.

<sup>222</sup> Public Utilities Commission of Texas. Chapter 25. Substantive Rules Applicable to Electric Service Providers. §25.53. Electric Service Emergency Operations Plans.

<sup>223</sup> Of the 97 units spot checked in 2019, 33 units that were deficient “agreed to improve preparations and/or records management” (Source: Allgower, A. Presentation at ERCOT Generator Winter Weatherization Workshop, September 5, 2019.)

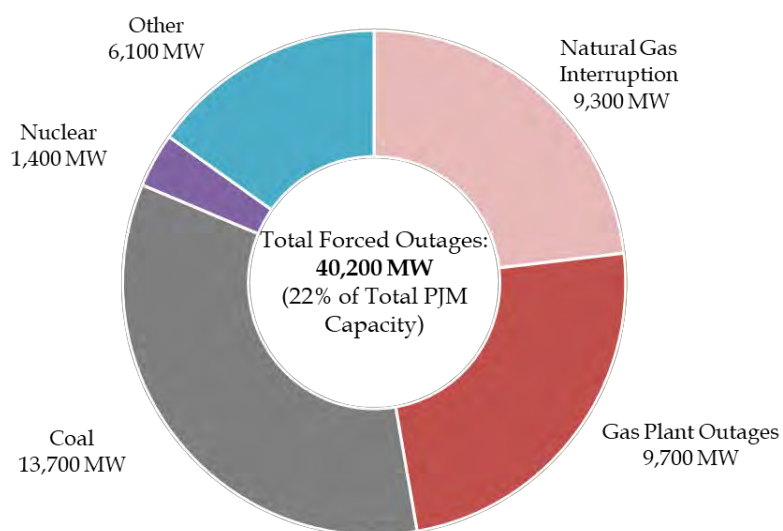
<sup>224</sup> ERCOT website. ERCOT calls for rotating outages as extreme winter weather forces generating units offline. February 15, 2021. News Release.

<sup>225</sup> NOAA database. CONUS. Heating Degree Days. March 18, 2021.

system imbalances. Natural gas well production and processing equipment froze in parts of the Marcellus Shale in Pennsylvania, impacting production. A natural gas compressor station in Delmont, PA, went offline, reducing capacity on Tetco by 575 MDth/d.<sup>226, 227</sup>

The PJM Interconnection (“PJM”), the regional transmission organization (“RTO”) encompassing 13 states including New Jersey, recorded a record winter peak electricity demand of 141,846 MW on the evening of January 7.<sup>228</sup> During this period, 22% of generation capacity was out of service, which is substantially higher than the usual normal winter peak outage rate of 7 to 10%. A large portion of the outages were associated with interruption in natural gas supplies served by IT contracts (see Figure 73). This indicates the system worked as planned – when gas transmission capacity is in short supply compared to demand needs, firm customers have first call on it. But it also showed how reliant the electric system is on natural gas supplies.

**Figure 73. PJM outages by generator fuel type January 7, 2014**



Source: “Winter Weather Procedure Changes Seminar.” PJM Interconnection. November 24, 2014.

In response to the 2014 polar vortex, PJM instituted Capacity Performance (“CP”) incentives to ensure that electric generating capacity would be available during a crisis and to make sure that generator improvements are made.<sup>229</sup> The CP rules were designed and “intended specifically to encourage resources to make needed upgrades in plant equipment, weatherization measures, fuel procurement arrangements, fuel supply infrastructure and other factors.”<sup>230</sup> The CP structure incorporates bonuses and penalties. Not being able to access natural gas is not an excuse for a gas

<sup>226</sup> Ibid.

<sup>227</sup> “Polar Vortex Review.” North American Electric Reliability Corporation. September 2014.

<sup>228</sup> “Winter Weather Procedure Changes Webinar.” PJM. November 24, 2014.

<sup>229</sup> “Strengthening Reliability: An Analysis of Capacity Performance.” PJM Interconnection. June 20, 2018.

<sup>230</sup> Ibid.

plant that has cleared the capacity market not to run; and if that is the case and the plant has a capacity award, the plant will be penalized for not generating if called upon.

The CP seems to have worked. During the cold snap from late December 2017 to early January 2018, PJM reported a 5.5% resource outage compared to the 12.4% resource outage rate during the 2014 Polar Vortex.<sup>231</sup> For New Jersey GDCs, the CP rules may mean that in the future, there could be more competition for IT on gas pipelines during a cold snap and more competition for FT on an ongoing basis. However, as an example of the effective use of new rules and regulations accompanied by rewards and penalties for preventing power outages, the CP illustrates a best practice.

### 7.3 New Jersey’s response to Hurricanes Irene and Sandy: Improved infrastructure and communications

Two major hurricanes hit the northeastern United States in 2011 and 2012. The impacts on New Jersey were substantial for both hurricanes (see Figure 74).

Figure 74. Hurricane Sandy and Hurricane Irene summary

	Hurricane Irene	Hurricane Sandy
Landfall Date	August 27, 2011	October 29, 2012
Strength at First US Landfall	Category 1 Hurricane	Post-Tropical Cyclone
Landfall Location	8/27 – Cape Outlook, NC (90 mph) 8/28 – Little Egg Inlet, NJ (80 mph) 8/28 – Coney Island, NY (75 mph)	10/29 – Atlantic City, NJ (80 mph)
Property Damage	\$10 billion	Est. \$20+ billion
Deaths	45	131

Source: “Comparing the Impacts of Northeast Hurricanes on Energy Infrastructure.” *Office of Electricity Delivery and Energy Reliability U.S. Department of Energy*. April 2013.

During Hurricane Irene, New Jersey’s two major interstate natural gas pipelines, Transco and TGP, continued to operate. The two pipelines reported that although some pumping stations experienced a loss of power or minor flooding, particularly in low-lying areas of their network, there were no interruptions of natural gas flows.<sup>232</sup>

Hurricane Sandy was a different story. Sandy caused worse damage to infrastructure and interrupted gas service to thousands of customers. NJNG shut down a portion of its natural gas

<sup>231</sup> “How the Polar Vortex Affected Energy Markets in the Midwest.” *Enel X*.

<sup>232</sup> Office of Electricity Delivery and Energy Reliability U.S. Department of Energy. “Comparing the Impacts of Northeast Hurricanes on Energy Infrastructure.” April 2013.

infrastructure and vented gas from its distribution pipelines, which allowed water to enter the pipes.<sup>233</sup> The damage caused by the water was severe and required parts of the distribution system to be replaced. Hurricane Sandy recovery costs totaled approximately \$50 million for all four New Jersey GDCs.<sup>234</sup> Overall, approximately 35,000 natural gas customers experienced interruptions in service during Hurricane Sandy.<sup>235</sup>

As discussed in Section 5.2.3, New Jersey's response to these events involved the hardening of gas distribution infrastructure and the development of a sophisticated emergency communications platform.

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<sup>233</sup> "Comparing the Impacts of Northeast Hurricanes on Energy Infrastructure." *Office of Electricity Delivery and Energy Reliability U.S. Department of Energy*. April 2013.

<sup>234</sup> "New Jersey Five Years Post-Sandy: Stronger Than the Storm." *New Jersey Department of Community Affairs*. October 2017.

<sup>235</sup> *Ibid.*



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