STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company for Electric Service	)))	**Case 19-E-0065**
Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company for Gas Service	)))	**Case 19-G-0066**

DIRECT TESTIMONY

OF

GREGORY LANDER

ON BEHALF OF

ENVIRONMENTAL DEFENSE FUND

Dated: May 24, 2019

I. Introduction and Qualifications

Q. Please state your name and business address.

A. My name is Gregory M. Lander. My business address is 83 Pine Street, Suite 101, West Peabody, MA 01960.

Q. What is your occupation and by whom are you employed?

A. I am President of Skipping Stone, LLC ("Skipping Stone").

Q. Please state your educational background and experience.

A. I graduated from Hampshire College in Amherst, Massachusetts, in 1977, with a Bachelor of Arts degree. In 1981, I began my career in the energy business at Citizens Energy Corporation in Boston, Massachusetts ("Citizens Energy"). I became involved in the natural gas business of Citizens Energy in 1983. Between 1983 and 1989, I served as Manager, Vice President, President and Chairman of Citizens Gas Supply Corporation (a subsidiary of Citizens Energy).

I started and ran an energy consulting firm, Landmark Associates, from 1989 to 1993, during which time I consulted on numerous pipeline open access matters, a number of Federal Energy Regulatory Commission ("FERC") Order No. 636 rate cases, pipeline certificate cases, fuel supply and gas transportation issues for independent power generation projects, international arbitration cases involving renegotiation of pipeline gas supply contracts, and natural gas market information requirements cases (FERC Order Nos. 587 *et seq.*). In 1993, I founded TransCapacity LP, a software and natural gas information services company.

Since 1994, I have also been a Services Segment board member of the Gas Industry Standards Board ("GISB") and its successor organization, the North American Energy Standards Board ("NAESB"). During the period 1994 to 2002, I served as a Chairman of the Business Practices Subcommittee, the Interpretations Committee, the Triage Committee, and several GISB/NAESB Task Forces. I am currently a Board Member of NAESB and have served continuously in that capacity since 1997.

Skipping Stone, Inc. acquired TransCapacity in 1999, and since that time I have headed up Skipping Stone's Energy Logistics practice, where my specialization has been interstate pipeline capacity issues, information, research, pricing, acquisition due diligence and planning. In 2001, Skipping Stone launched CapacityCenter.com, a pipeline capacity information service. In 2004, Skipping Stone was acquired by Commerce Energy Group, a national retail energy services provider. In 2005, I was appointed President of Skipping Stone, which operated as a wholly owned subsidiary of Commerce Energy Group. In 2008, I purchased substantially all of the assets of Skipping Stone and now operate essentially the same business as before the Commerce Energy transaction as Skipping Stone, LLC.

From 1984 to present, I have maintained a deep familiarity with a wide range of pipeline transportation issues, beginning with access to pipeline capacity to make competitive sales, resolution of the pipeline take-or-pay contracting regime, pipeline affiliate marketer concerns, restructuring of the pipelines from merchants to transporters and thereafter, and definitions of what constituted a pipeline capacity "right" for the purposes of formulating the then newly commenced capacity release and capacity rights trading business process. I continue to be involved in nearly all facets of the capacity information and trading business as part of my duties at Skipping Stone. In addition, I have been the lead principal on all 50+ pipeline and storage mergers and acquisitions transactions as well as all pipeline and storage facility expansion projects for which Skipping Stone has been retained by potential purchasers and project sponsors to provide economic due diligence consulting and market analysis. In addition, I have testified before, participated in or assisted with proceedings before, state public utilities commissions and/or their staffs in the states of Maine, Massachusetts, Missouri, Virginia, South Carolina, California, Rhode Island and New Jersey with respect to infrastructure matters, integrated resource plans, and fuel cost recovery proceedings. Please refer to Exhibit __ (GL-1), which contains my current CV.

Q. Have you previously filed testimony before regulatory commissions?

A. I have filed testimony before the Massachusetts Department of Public Utilities, the Maine Public Utilities Commission, the Virginia Corporation Commission, the Missouri Public Service Commission, the California Public Utilities Commission, and the South Carolina Public Service Commission. I have also filed testimony in several FERC proceedings. Please refer to Exhibit __ (GL-1), which contains a full list of case names and docket numbers in which I have participated as a witness.

Q. On whose behalf are you testifying in this proceeding?

A. I am submitting testimony on behalf of the Environmental Defense Fund ("EDF").

II. Purpose of Testimony and Recommendations

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to: (1) detail the deficiencies in Con Edison's gas supply planning, considering the information provided in Con Edison's testimony and data responses; and (2) provide recommendations regarding how the Company's gas supply planning process could be improved.

Q. Please provide a summary of your testimony and recommendations.

A. The first portion of my testimony explains the deficiencies in Con Edison's gas supply planning. I first explain that the January 17, 2019 notice announcing a moratorium in Westchester County is evidence that the Company has not satisfied its stated objective of meeting the design winter requirements of firm gas customers. I next conduct an analysis demonstrating that hourly takes have exceeded hourly contract rights in Westchester and conclude that Con Edison knew or should have known in 2010 that additional peak hour capacity was or would be required in the near term. Evaluating the actions taken by the Company since 2010 to address its capacity need, I find that the Company has failed to plan sufficiently for its system. To address this deficiency, I propose a 50-100 basis point reduction for every year during which a moratorium on conversions or new connections in any part of the Company's territory is in effect.

The second portion of my testimony pertains to the Company's Mountain Valley Pipeline ("MVP") transportation contract, in which the Company's affiliate, Con Edison Transmission, has an investment interest. I explain the risks associated with one company being both pipeline developer and pipeline shipper. I next share an analysis demonstrating that, instead of committing its ratepayers to unnecessary 20-year fixed costs, the Company could have purchased gas out of MVP and into Transcontinental Pipe Line Company LLC's ("Transco") Zone 5 using its existing transportation rights on the Transco pipeline to bring that gas to its citygate. To protect ratepayers against the unnecessary fixed cost burden, I recommend that the New York Public Service Commission ("Commission") limit recovery of gas and capacity costs (for those dekatherms acquired through MVP) to the lesser of prices reported for Transco Zone 4, Transco Zone 5, or Transco Zone 6.

The third portion of my testimony provides an overview of the current gas supply planning process in New York and compares this process to other states. To address the Company's gas supply planning deficiencies, I propose three recommendations. I first suggest that the Company should be subject to an annual gas supply process, with discovery rights for intervenors and technical conferences as needed. I next suggest that the Company should be required to submit a long-range plan, which would become the basis for future cost recovery. The long-range plan would set forth projections of demand and resources to meet that demand, identifying the "all-in" cost for each resource. Finally, I suggest additional categories of information the Company should submit in order to assist the Commission in its review of gas supply issues. Taken together, I explain how these refinements will help identify potential issues well in advance of experiencing demand/supply mismatches requiring moratoria; manage the fixed costs commitments made by the Company; and provide a more thorough framework for the Company to consider alternatives that would have lower all-in costs to customers.

Q. Was your testimony prepared by you or under your supervision?

A Yes.

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring the following exhibits:

Exhibit __ (GL-1): CV and List of Expert Testimony of Gregory M. Lander

Exhibit __ (GL-2): Con Edison Response to EDF-1-2; Case No. 17-G-0606

Exhibit __ (GL-3): Con Edison Response to EDF-1-1; Case No. 17-G-0606

Exhibit __ (GL-4): Applied Economics Clinic Report on MVP Pipeline

Exhibit __ (GL-5): Letter from Con Edison to EDF; Case No. 93-G-0932

Exhibit __ (GL-6): Winter Supply Review Data Request; Case No. 18-M-0272

Exhibit __ (GL-7): Con Edison Response to EDF-2-1; Case No. 17-G-0606

Exhibit __ (GL-8): Rhode Island Joint Memorandum; Docket 4816

III. Failure to Sufficiently Plan for System Needs

Q. Please explain the high level objectives that appear to guide Con Edison's gas supply planning.

A. The Gas Infrastructure, Operations and Supply Panel sets forth the following objectives:

> The Companies' objective is to obtain reliable, diverse, and reasonably-priced gas supply in order to: (i) meet the design winter requirements of firm gas customers, (ii) minimize costs to firm customers; (iii) reduce price volatility, (iv) react to changing weather conditions, and (v) to the extent possible, maintain service during a contingency event affecting a major pipeline or supply basin.[1]

Q. Do you agree that gas utilities should obtain or arrange for gas supply in order to meet the design winter[2] requirements of firm gas customers?

A. Yes. This is a fundamental requirement of gas utilities, embedded within New York statute[3] and Commission orders.[4]

---

[1] Gas Infrastructure, Operations, and Supply Panel Testimony at page 148, lines 5-12.

[2] As explained by the Company, a "design" winter includes the gas requirements for meeting demand over the course of a winter under severe weather conditions. Gas Infrastructure, Operations, and Supply Panel Testimony at page 149, lines 19-22.

[3] Public Service Law § 30 ("It is hereby declared to be the policy of this state that the continued provision of all or any part of such gas, electric and steam service to all residential customers without unreasonable qualifications or lengthy delays is necessary for the preservation of the health and general welfare and is in the public interest.").

[4] *In the Matter of the Commission's Request for Gas Distribution Companies to Reduce Gas Cost Volatility and Provide for Alternate Gas Purchasing Mechanisms*, Case No. 97-G-0600, Statement of Policy Regarding Gas Purchasing Practices (April 28, 1998) ("We expect companies to manage their gas portfolios to meet the needs of their systems").

Q. Has the Company satisfied its stated objective of meeting the design winter requirements of firm gas customers?

A. No. As evidenced by the January 17, 2019 notice announcing a temporary moratorium on the addition of new firm gas customers in most of Westchester County, the Company has not satisfied the objective of meeting the design winter requirements of firm gas customers.

Q. Did the Company identify the need for new pipeline capacity prior to the January 17, 2019 notice of moratorium?

A. Yes, the Company's 2010 Gas Long Range Plan acknowledges the need for additional new pipeline capacity, stating "[a]dditional gas supply will need to be provided through multiple points of delivery from the interstate pipeline systems into our service area."[5]

Q. Do you agree with that statement?

A. That statement was not only true in 2010, but based upon an analysis I performed on data provided in discovery, Con Edison should have been planning at the time it issued its 2010 Long Range Plan to obtain additional pipeline capacity to serve the Westchester service area that was, and is, supplied primarily by Tennessee Gas Pipeline ("Tennessee").

Q. Please explain your analysis and how you came to this conclusion.

A. In response to EDF_3_33, the Company provided an Attachment_1_ CONFIDENTIAL. The discovery request asked for hourly flow data at all of the

---

[5] Con Edison Gas Long Range Plan 2010-2030 at page 91, Section 4.3.2 (December 2010), available at http://158.57.189.31/publicissues/PDF/GLRP1210c.pdf.

Company's take stations from interstate pipelines as well as Company receipts from its Liquefied Natural Gas ("LNG") and Compressed Natural Gas ("CNG") facilities for the period of November 1, 2015 through March 31, 2019. I first analyzed the data with respect to the flows from Tennessee into the Company's facilities in Westchester. I then compared those hourly flows to the hourly contract rights under Con Edison's and under third parties' (i.e., non-Company) contracts with those Westchester locations as primary delivery locations.[6]

Q. Please provide a high level overview and objective of your analysis.

A. My analysis sought to determine (1) whether hourly takes have exceeded hourly contract rights and (2) when the Company would have reasonably first become aware of such exceedances. If hourly takes exceed hourly rights, this is an indication that demand served by gas from the location is exceeding contract rights. If the exceedance happens infrequently, the situation should be monitored and plans formulated. Such plans could include subscribing to additional capacity, increasing peak shaving capability, pursuing non-pipeline alternatives, and/or pursuing more rigorous demand-side solutions. If the exceedance happens frequently, then plans should proceed from formulation to execution. The key to the type of plan and urgency of execution lies in the analysis of the frequency, duration, magnitude, and timing (i.e., season) of the exceedances. This type of

[6] Under firm pipeline contracts, primary locations are those contracted capacity locations where the pipeline has the obligation to deliver (when the location is a primary delivery point) or receive (when the location is a primary receipt point) the daily, and, unless otherwise specified in the contract, the tariff specified hourly quantity of gas for the account of the shipper.

analysis is essential to planning because of the risk that under high demand, winter conditions a pipeline can insist that it only provide contractually permitted/obligated service. In other words, a history of taking delivery of pipeline gas in excess of contractual entitlement is a clear indication of a need for additional supply arrangements. I focused on the Tennessee delivery points in Westchester (i.e., White Plains, Knollwood, and Rye), as the Company's January 17, 2019 moratorium specifically refers to Westchester County. My analysis looked at the demand in two relevant periods (2015/2016 winter and 2017/2018 winter). I then assume a very conservative 3% year-over-year growth in peak hourly demand and perform a "back cast" calculation to determine when firm hourly rights were first being exceeded.

Q. Please explain which specific contracts you reviewed as part of this analysis.

A. For this analysis I located all of the Tennessee contracts that existed as of January 1, 2010, January 1, 2015, and January 1, 2019 which had those Westchester locations as primary points under the contracts. Those contracts included the Company's contracts, contracts of delivered service providers (mostly marketers) and contracts of National Grid.[7] The hourly contract rights of the shippers (including Con Edison) and the firm hourly service obligation of Tennessee specifies that the hourly takes are limited to 1/24 of the daily scheduled quantity.

[7] While National Grid has no facilities in Westchester County, it has contract rights on Tennessee to deliver to Con Edison in [redacted]. I am unaware of the conditions, if any, where Con Edison can cause National Grid to make deliveries to Westchester on Tennessee.

Any hourly takes above that quantity are interruptible and any daily takes above the daily maximum daily quantity at the location are interruptible.

Q. Did you focus on a particular timeframe?

A. In this comparison, I first looked at the winter of 2015/2016 (i.e., November 1, 2015 through March 31, 2016) and then looked at the winter of 2017/2018 (i.e., November 1, 2017 through March 31, 2018).

Q. And what did you find?

A. The hourly takes during the winter of 2015/2016 at the Company's largest contracted Westchester take station, [redacted], exceeded Con Edison's maximum firm primary point hourly contract rights in [redacted] hours in this same winter period. The maximum hourly contract rights of the Company at [redacted]_are (and were) 2,601 Dth/Hr.[8] Looking at the 2015 contracted capacity levels and adding in the hourly contract rights of all other 2015 shippers (excluding National Grid) with [redacted]

[8] Under the Company's Tennessee contracts, it has a greater quantity of daily (and thus hourly) primary delivery point rights than the total daily capacity rights under its contracts with [redacted]_as one of the primary delivery points. The 2,601 Dth/Hr figure under all such contracts if taken at [redacted] means that lesser quantities than maximum have to not be taken at other primary delivery points in order to have all deliveries considered firm.

[redacted] as a primary delivery point, the total contracted capacity increases to 7,397 Dth/Hr.[9] The hourly takes back in 2015 were above this level in [redacted] winter hours or [redacted] of the time. The maximum hourly take in the winter of 2015/2016 was [redacted] Dth/Hr. In the winter of 2017/2018, the maximum hourly take had grown to [redacted]—[redacted] of total contractual entitlements.

For 2015, looking at the portion of Westchester County served by Tennessee take stations, the total contracted hourly quantities of all shippers (including National Grid), and, looking at hourly takes across all the Westchester Tennessee take stations, the total contracted hourly quantity was 10,128 Dth/Hr. Against this contracted hourly quantity, the sum of hourly takes exceeded this quantity during [redacted] winter hours in 2015 or [redacted]—[redacted] of the time. And, peak hourly flows registered [redacted] Dth/Hr or [redacted]

[9] In 2015, the total contracted primary hourly rights to [redacted] were only 8,917 Dth/Hr. This figure is inclusive of 2015 contract rights held by National Grid.

[redacted] of total contractual entitlement.

Q. What is the significance of these calculations?

A. By my calculations, in 2010 when Con Edison issued its Long Range Plan, hourly takes were already exceeding hourly rights at [redacted] in particular and Westchester in general. Looking at the peak hourly flows in winter of 2015/2016 and assuming a very generous 3% year-over-year growth in peak hour demand (as compared to the Company's suggested growth rate, which is significantly lower) and then working back from the 2015/2016 demand, indicates that firm hourly rights were being exceeded in the winter of 2009/2010.[10] In addition, unless Con Edison had contracted, and would continue to contract, with each of these non-National Grid shippers for firm delivered supply, Con Edison would not have been able to rely on that capacity and supply to be there. In another words, it was a risk factor that was knowable in 2010.

Q. Please explain why you assumed a 3% year-over-year growth of peak demand.

A. This growth rate is very generous to the Company. In my experience I have generally seen peak hour demands increase in line with daily and annual demands. However, peak hours' demands are not typically 1/24th of peak days'

[10] Using a growth rate closer to that indicated by the Company and again working back from 2015/2016 peak hours would have the Company exceeding hourly contracted capacity rights before winter of 2004/2005.

demands. The typical growth rate is generally 1-2%,[11] absent the introduction of a major gas consuming industrial or gas-fired power plant. This demonstrates that my 3% growth rate assumption is conservative. Had I used the more typical 1-2% rate working back from 2015/2016, I would have concluded that the Company would have seen contracted hourly rights being exceeded before the winter of 2004, not 2009/2010 as my indicative calculations demonstrate.

Q. What are your conclusions and what are the implications of your conclusions?

A. My conclusions are that Con Edison knew or should have known by the time it issued the 2010 Long Range Plan that additional peak hour capacity was or would be required in the near term. That capacity need could be addressed by pipeline, internal distribution expansions, or perhaps offset by non-pipeline solutions. In my view the Company's actions were an avoidable and imprudent failure of analysis, or planning or both. My review of the contract and flow data indicates that in 2015[12] that Con Edison was already heavily reliant on Delivered

---

[11] Gas Volume and Revenue Forecasting Panel at page 17, line 24 (setting forth an average annual growth rate of approximately 1.7%); *see also Proceeding on Motion of the Commission as to the Rates, Charges, Rules, and Regulations of KeySpan Gas East Corp. d/b/a National Grid for Gas Service*, Case No. 19-G-0310, Direct Testimony of Elizabeth D. Arangio at page 14, lines 8-10 (April 2019) ("KEDNY and KEDLI expect the demand for gas to grow at an annual rate of more than 1.3 percent and 1.0 percent for the next ten years, respectively").

[12] Based on reasonable back-casting calculations, the Company should have at least recognized this as far back as the winter of 2009/2010.

Services,[13] secondary delivery rights,[14] and/or forbearance by Tennessee[15] or a combination of all three. Together, these factors demonstrate that the Company should have taken steps beginning in 2010 to address this need. Subscribing to new projects in 2010 was, in my view, just as feasible in 2010 as now (nine years later). In any event, the Company should not have waited until 2018/2019 to address this reality.

Q. Did the Company acknowledge the need for new pipeline capacity after issuing its 2010 Long Range Plan?

A. Yes. The Company's 2016 rate case testimony also acknowledged the need for new pipeline capacity. Ivan Kimball, the Company's witness, stated:

> Our projected demand growth over the next few years indicates a need for new pipeline capacity to the NYC region. There are two means for meeting our demand: (1) either procure additional capacity from existing capacity holders or (2) become a shipper on new pipeline projects to the NYC citygates. Because of the limited availability of unsubscribed capacity on existing pipelines, and the long lead time of new pipeline

---

13 As explained by the Company, Delivered Services have historically been "firm peaking supplies that give the option to purchase gas for a pre-determined number of days during the winter (typically 15, 30, or 60 days) and pay the daily citygate index price for the gas on those days." Gas Infrastructure, Operations and Supply Panel at page 150, lines 10-14.

14 Secondary delivery rights are rights that shippers have that permit them to make deliveries to points in addition to (and other than) the "primary points" specified in their contracts. These types of deliveries, while often reliable depend on operational conditions and are not "guaranteed."

15 Here "forbearance" is meant to convey that Tennessee may have permitted the excursions beyond hourly contracted rights at the time because the excursions did not negatively impact other parties' scheduled services.

projects to the citygate, the Company has started to explore and evaluate potential pipeline projects that come to the NYC region.[16]

Q. Did the Company take steps to address this identified need between 2010 and 2016?

A. The Company has stated that it contracted for service on a new pipeline project in November of 2013, the Spectra NJ-NY expansion project, which included the creation of a new citygate delivery point in Lower Manhattan.[17] The Company has also indicated that it has entered into service agreements with pipelines for pipeline capacity that has been turned back and not renewed by other existing capacity holders.[18]

Q. Were these efforts sufficient?

A. No, only one of these contracts increased Con Edison's capacity into Westchester County[19] and it did not obviate the need for the Company to announce a moratorium in January 2019. Other contracts entered into by Con Edison included an Iroquois contract that increased Con Edison's contracted capacity at Hunts

---

16 *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Gas Service,* Case No. 16-G-0061, Ivan Kimball Gas Supply Testimony at page 21, line 22 to page 22, line 9 (January 29, 2016).

17 Exhibit __ (GL-2).

18 *Id*.

19 *See* Exhibit __ (GL-7). The Tennessee contract #323455 as amended increases Con Edison's contracted capacity to Rye by 25,625 Dth/day (~1,068 Dth/Hr) and to White Plains by 5,000 Dth/day (~208 Dth/Hr) in November of 2020.

Point (Lower Bronx).[20] While the Spectra[21] (Texas Eastern) project that went into service in late 2014 brought needed capacity to Manhattan, at present the limited transfer capacity within the Con Edison system to move gas from Manhattan (or the Bronx) to Westchester did not address the Westchester situation discussed above. The Con Edison contracted capacity on the Texas Eastern project today represents ~17% of the Company's total contracted citygate primary point capacity,[22] which is far from sufficient to address its citygate capacity needs.

Q. Did the Company take any additional steps to meet its planning obligations?

A. Yes, in September 2017, the Company filed its Smart Solutions petition with the Commission to develop alternative solutions to meet growing gas peak demand.[23] The program includes four non-traditional solutions (energy efficiency, gas demand response, renewable alternatives to natural gas, and a market solicitation for additional non-pipe solutions) and one traditional solution (natural gas pipeline).

---

[20] *Id.* The Iroquois contract increases Con Edison's contracted capacity to Hunts Point by 20,000 Dth/day. Under the Iroquois Tariff, Con Edison can receive a maximum of 5% of daily scheduled supply (1,000 Dth/Hr under this contract) for up to three consecutive hours twice in a 24-hour period, provided the second 5% (1,000 Dth/Hr) take starts no sooner than eight hours after the end of the first maximum take period.

[21] Spectra which owned Texas Eastern was merged into and is now owned by Enbridge.

[22] The Texas Eastern posting of firm contracts as of January 1, 2019 shows Con Edison with 170,000 Dth/d contracted to "ConEd-Manhattan Delivery." Other shippers hold an additional 630,000 Dth/day to Con Edison at this same location.

[23] *Petition of Consolidated Edison Company of New York, Inc. for Approval of the Smart Solutions for Natural Gas Customers Program*, Case No. 17-G-0606 (September 29, 2017) ("Smart Solutions Petition").

Q. Was this suite of non-traditional solutions sufficient to address the Company's obligation to plan for its firm customer needs?

A. No, the Smart Solutions Petition states that "the Enhanced Gas EE Program, the Gas DR Program, and the Gas Innovation Program may provide relief to meet approximately three percent of the Company's overall pipeline capacity needs by 2023. Assuming a gas supply portfolio that would include up to 10 percent of Delivered Services the Company still anticipates a shortfall of approximately nine percent of peak day gas needs in 2023, prior to the impact of the Non-Pipeline RFI."[24]

Q. In other words, at the time the Company submitted its Smart Solutions Petition to the Commission, the Company acknowledged that its suite of non-traditional solutions would likely be insufficient to address system needs?

A. Yes.

Q. Is it fair to say that the Company failed to plan sufficiently for its system?

A. Yes. While the Company took certain steps outlined above to address its capacity needs, these steps did not obviate the Company's need to announce a moratorium in January 2019. Moreover, as demonstrated by the statements in the Company's 2019 Gas Long Range Plan, moratoriums appear to be a potential future management tool going forward.[25] The announcement of a moratorium should

---

[24] *Id.* at page 26.

[25] Con Edison Gas Long-Range Plan 2019-2039 at page 18 (January 2019), https://www.coned.com/-/media/files/coned/documents/our-energy-future/our-energy-projects/gas-long-range-plan.pdf ("While we continue to develop clean

only be a step of last resort after the Company has vigorously explored supply and demand solutions.

Q. The Company has asserted that "[a]fter the New York State Department of Environmental Conservation denial of Constitution Pipeline's state water permit on April 22, 2016, pipeline developers became increasingly concerned about doing business in New York. As a result, the Company recognized increasing uncertainty about its ability to negotiate precedent agreements with pipeline developers for projects that would ultimately require approval from federal, state and local agencies." (Exhibit __ (GL-3)). What do you make of this assertion?

A. This assertion is belied by the two recent projects subscribed to by Con Edison. First, on April 24, 2019, Con Edison announced that it had entered into a precedent agreement[26] with Tennessee for the East 300 Upgrade Project, a proposal to modify Tennessee's existing 300-Line in Pennsylvania and New Jersey to provide Con Edison with up to 110,000 dekatherms per day of firm

heating alternatives, we must continue to take the steps needed to provide reliable service to all of our customers through the clean energy transition, which may include additional temporary moratoriums.").

[26] Precedent agreements set forth the commercial, financial, and operational terms for new pipeline builds, committing the pipeline to build the project and the shipper to purchase the expansion capacity. Once a pipeline is approved and placed into service, the terms of a precedent agreement are carried over to an agreement for transportation service and the pipeline provides service to the shipper pursuant to these terms, along with any applicable tariff requirements.

transportation service.[27] Con Edison also recently announced an agreement with Iroquois Gas Transmission System L.P. to upgrade the pipeline's compression facilities by November 2023.[28]

Q. In your experience, are pipeline developers willing to negotiate precedent agreements with customers who sign up for firm service?

A. Yes, a repeated refrain from the pipeline industry is that "[n]atural gas transmission infrastructure is built to serve the economic needs of the market and is supported by shippers willing to commit to long-term firm transportation contracts to use the capacity."[29] Transco's Atlantic Sunrise Project, Dalton Expansion Project, and Virginia Southside Expansion Project; Columbia Gas Transmission LLC's WB Xpress Project (to feed other pipelines' flow reversal[30] projects), and Texas Eastern's myriad of flow reversal projects[31] are but a few of the projects that obtained the required environmental permits and were built based

---

27 https://www.coned.com/en/about-con-edison/media/news/20190424/con-edison-seeks-expanded-natural-gas-capacity.

28 https://www.coned.com/en/about-con-edison/media/news/20190509/con-edison-to-enhance-gas-deliverability-for-nyc.

29 The INGAA Foundation, Inc., The Role of Natural Gas in the Transition to a Lower-Carbon Economy at 6 (May 2019), *available at* https://www.ingaa.org/File.aspx?id=36337&v=11f69171.

30 "Flow reversal" is the term used to describe those projects where traditional Gulf Coast to Northeast capacity is reversed to be able to flow from North to South thus becoming bi-directional based upon supply and demand dynamics.

31 Examples include Texas Eastern's Gulf Markets, OPEN and TX-LA Markets Projects, among others.

upon the economic support of long-term agreements to unlock pent up supply and/or meet proven demand.

Q. Given Con Edison's failure to satisfy its own planning objectives, would you agree that some type of negative adjustment or penalty is warranted?

A. Yes. Just as the Company has proposed various positive incentives associated with achieving certain metrics,[32] the Company should also be subject to negative adjustments with respect to its failure to plan appropriately to meet the current and forecasted capacity needed to serve current and forecasted customer demands.

Q. Please explain what you mean by negative adjustment.

A. Given the choice of Con Edison to either ignore or fail to take notice of (and in either case fail to respond to) the growing peak hour requirements of winter period demand in the Westchester area of its service territory, the negative adjustment should be significant. I propose a 50-100 basis point reduction for every year, during which a moratorium on conversions or new connections in any part of its territory is in effect.

Q. What is your rationale for the 50-100 basis point reduction in ROE and why is that proposal reasonable?

A. The situation which has led to the declaration of a moratorium lasting until as late as the winter of 2023 – four years from now – should never have come to this point and has resulted in harm to the public welfare. A significant ROE adjustment sends a lasting message to Con Edison that this should not be allowed

[32] *See, e.g.*, Gas Policy Panel Testimony at page 51, lines 9-20.

to happen again. Such a disincentive/negative adjustment should also spur the Company to quickly resolve the issue whether by means of a right sized project or non-pipeline alternative(s).

Q. You noted that the moratorium has resulted in harm to the public welfare. Please explain.

A. The harm resulting from the moratorium has been well documented by Westchester city and county officials and other impacted stakeholders, ranging from economic harm[33] to harm to the health and safety of residents.[34]

Q. Has this Commission acknowledged that it may be appropriate to reduce rate of return in some instances?

A. Yes. This Commission has previously found that rate of return may be reduced even to zero if management errors are sufficiently egregious.[35] Other state

---

[33] *See, e.g.*, *In the Matter of Staff Investigation into a Moratorium on New Natural Gas Services in the Consolidated Edison Company of New York, Inc. Service Territory*, Case No. 19-G-0080, Comments of the County of Westchester and Request for an Order Holding Moratorium in Abeyance Until the Commission Takes Action on the Staff Investigation at pages 5-6 (February 25, 2019) (explaining that the announcement of a moratorium "sent a chill through the development community in Westchester" and documenting the economic harm caused by the moratorium).

[34] *See, e.g.*, *In the Matter of Staff Investigation into a Moratorium on New Natural Gas Services in the Consolidated Edison Company of New York, Inc. Service Territory*, Case No. 19-G-0080, Public Statement Hearing Transcript at pages 38 (February 13, 2019) (Jason Baker, Director of Sustainability for the City of Yonkers, testifying that "[w]e are not just talking about economic development of private dollars, we are talking about the health and safety of Yonkers' families").

[35] *United Water New York, Inc. Second Stage Rate Filing to Increase Its Annual Revenues*, Case No. 96-W-0294, Order Denying Rehearing at 7 (October 9, 1996) (citing *Hurley Water Co., Inc. v. Public Service Commission*, 87 A.D.2d 678 (3rd Dept., 1982), *app. den.* 58 N.Y.2d 601).

commissions have reduced ROE in instances where the utility was unable to perform fundamental functions such as providing adequate service.[36] Under the same logic, I am proposing a measured, but significant, basis point reduction to address the inadequacies of the Company's gas supply planning. This planning requirement is one of the cornerstones upon which traditionally regulated utilities are entitled to seek ratepayer compensation and a return on their investments and should not be simply ignored.

Q. Has this Commission acknowledged the connection between Con Edison's moratorium and this rate proceeding?

A. Yes, Chair Rhodes' January 28, 2019 "Statement on Consolidated Edison's Decision to Stop Accepting New Gas Customers on a Temporary Basis in Westchester County" provides that "[t]he Commission will continue to use all available methods – including its rate-making authority – to push utilities to address changing market dynamics in a manner that promotes both the State's clean energy objectives and economic growth."[37]

---

[36] *See, e.g.*, *Emera Maine Request for Approval of a Proposed Rate Increase*, Maine Public Utilities Commission Docket No. 2015-00360 (Order Part II) (December 22, 2016) (imposing a 50 basis point reduction to ROE and noting that a "standard of conduct is expected of utilities, that they operate efficiently, and that the failure to do so should be recognized in rates because it is presumed that inefficiency is harmful to ratepayers").

[37] *In the Matter of Staff Investigation into a Moratorium on New Natural Gas Services in the Consolidated Edison Company of New York, Inc. Service Territory*, Case No. 19-G-0080, Statement from Public Service Commission Chair John B. Rhodes on Consolidated Edison's Decision to Stop Accepting New Gas Customers on a Temporary Basis in Westchester County (January 28, 2019).

IV. Mountain Valley Pipeline

Q. Do you have any additional concerns regarding the Company's gas supply planning efforts?

A. Yes. The Company has committed its ratepayers to a long-term contract for pipeline capacity that does not provide any increase in capacity to Con Edison's service territory nor any meaningful benefits to customers. In fact, the contract will needlessly increase costs to customers when other, superior alternatives were available.

Q. You previously detailed the Company's failure to sufficiently plan to meet its system needs. Are you now saying that the Company entered into a contract that is not needed?

A. Yes. Not all pipeline capacity contracts are the same. A gas utility will enter into a capacity contract to either serve a growing market or to economically access new lower cost supplies and/or to replace supplies when one or more existing supply basins have been depleted. The former type of contract would address the Company's citygate capacity needs, which I discussed above. The Mountain Valley Pipeline ("MVP") contract I discuss below is needed neither to serve a growing market nor to economically access new lower cost supplies, nor to offset depletion of existing supply basins.

Q. Please describe the MVP Project.

A. The MVP project includes construction of both pipeline and compression facilities in West Virginia and Virginia and is designed to transport natural gas from the "Marcellus and Utica shale regions to the growing demand markets in the Mid-Atlantic and Southeast areas of the United States."[38]

Source: *Wood Mackenzie. 2017. Mid-Atlantic Natural Gas Demand in Support of the Mountain Valley Pipeline Project.*

Q. Please further explain terms of the MVP contract.

A. The Gas Infrastructure, Operations and Supply Panel explains that the Companies have subscribed to 250,000 Dt/d of pipeline capacity on Mountain Valley Pipeline, in which the Company's affiliate, Con Edison Transmission, has an investment interest.[39] Under the terms of the arrangement, and assuming Con Edison seeks cost recovery in one or more gas cost reconciliation proceedings, Con Edison ratepayers will pay MVP for 250,000 Dth/d of firm transportation

[38] Mountain Valley Pipeline Application for Public Convenience and Necessity, FERC Docket No. CP16-10 at Exhibit Z-4 – Open Season Notices (October 23, 2015) ("MVP Application").

[39] Gas Infrastructure, Operations, and Supply Panel Testimony at page 158, lines 7-11.

service capacity for a term of 20 years regardless of whether the capacity is needed or actually used. Historically, Con Edison recovers these costs because they are ultimately passed through to ratepayers as part of an annual gas cost reconciliation process.[40]

Q. Are there risks associated with one company being both pipeline developer and pipeline shipper?

A. Yes. Among the risks are (1) a lack of arms-length dealings in setting commercial terms; and (2) subsidization by ratepayers—to the extent such contracts are submitted for cost recovery by the regulated entity without first being vetted and approved as part of a long-range plan where need can be established and economic alternatives reviewed, as is the case in New York.

Q. Do Con Edison's shareholders stand to gain from the MVP investment?

A. Yes. The opportunity for shareholders to enjoy a hearty rate of return cannot be ignored as a significant motivation for joining the project. Although the MVP shippers have signed up for negotiated rates and thus the precise return on equity cannot be calculated from publicly available documents, MVP's application requests a 14% return on equity and calculates recourse rates using a pre-tax return of 15.77%.[41]

---

40 *See, e.g.*, Consolidated Edison Company of New York, Inc., 2016 Annual Gas Cost Reconciliation, Case No. 16-G-0431 (October 14, 2016).

41 MVP Application at 37; *see id.* at Exhibit P, Schedule 5. In terms of total costs of the project, the pre-tax return equates to $567,731,695 of the total $710,320,684 cost of service. MVP Application, Exhibit P, Schedule 2 (compare line 4 with line 7).

Q. Could Con Edison have taken advantage of any benefits the MVP Pipeline might provide, without taking an ownership interest and signing up for service on the pipeline?

A. Yes. Mountain Valley Pipeline filed its certificate application with FERC on October 23, 2015.[42] However, Con Edison did not become a shipper on the project until January 22, 2016; and, when Con Edison did become a shipper, another affiliate of the pipeline sponsor reduced their contracted capacity by the amount that Con Edison contracted for.[43]

Q. What is the significance of this timing?

A. The MVP project would have moved forward, based on the contracts set forth in its certificate application, regardless of whether Con Ed decided to take both an owner and shipper stake. Con Edison could have gained access to gas supplies from the MVP project regardless of whether it took an ownership stake in the project.

Q. Please explain the primary reasons pipeline customers would enter into a take-or-pay contract for new pipeline capacity.

---

42 MVP Application at 16.

43 Mountain Valley Pipeline Project, Docket No. CP16-10 Supplemental Information (January 27, 2016) (explaining that USG Properties Marcellus Holdings, LLC, a MVP shipper, has agreed to reduce its firm transportation capacity commitment by 250,000 Dth per day in order to accommodate the Con Edison precedent agreement).

A. Pipeline customers voluntarily enter into take-or-pay contracts for "firm" transportation capacity[44] over long periods of time for two primary reasons. If they are a producer-supplier, the primary reason is to gain access to better priced markets or gain market outlet for otherwise stranded supplies.[45] For buyers (primarily Local Distribution Companies), the primary reason to increase contracted long-term pipeline capacity is to serve a growing market or economically access new supplies, including when existing supply basins have been depleted. Over shorter periods and with existing capacity, all market participants that enter into firm contracts with pipelines do so when they determine that the cost of the capacity contract is less than the price differential between the supply points and the delivery points over the period of the contract.

Q. Please further explain the significance of the price differential between the supply points and the delivery points.

A. The price differential between the supply points and the delivery points is referred to as the "basis differential." Assuming the weighted average basis differential is

---

[44] *See Regulation of Short-Term Natural Gas Transportation Services and Regulation of Interstate Natural Gas Transportation Services*, Order No. 637, FERC Stats. & Regs. ¶ 31,091 at 31,271 (2000) ("The implicit price for transportation represents the most any shipper purchasing delivered gas at a downstream market would pay to move gas from the lower priced market to the higher priced market. For instance, the implicit value of transportation between the Henry Hub and the Chicago city gate was $.07 in September 1999 (the difference between the $2.67 price for gas in Chicago and the $2.60 price at Henry Hub).").

[45] In the case of stranded supplies, a producer, absent access to pipeline capacity, could face a heavily discounted or even zero-price situation which, in the latter case, would mean that any net positive price after taking account of capacity cost could justify subscription.

equal to or greater than the cost of transport over the duration of the contract, the shipper is thus capturing an arbitrage opportunity (i.e., profit as a seller or savings as a buyer) across a transportation network. In the natural gas transportation market, when ***new*** capacity is added to a system, that basis differential disappears the day the ***new*** pipeline capacity comes into service, as the new capacity provides a new delivery pathway between the two pricing points to eliminate the basis differential.[46]

Q. Could the Company have taken advantage of this basis differential disappearing without committing its ratepayers to a 20-year fixed transportation contract?

A. Yes. It could have done so by purchasing gas out of the MVP and into Transco Zone 5 using its existing transportation rights on the Transco pipeline to bring that gas to its citygate. Under the Company's existing transportation rights on the Transco pipeline, the Company can purchase gas into that capacity along the path of the Transco transportation capacity between Con Edison's primary receipt and primary delivery points. On Transco, Con Edison's full path capacity begins in Transco Zone 4 and continues through Transco's Zones 5 and 6. This means that Con Edison can "fill" its Transco capacity to serve its New York City markets by buying gas in any one or more of these Transco zones. It also means that Con

[46] Quadrennial Energy Review First Installment: Transforming U.S. Energy Infrastructures in a Time of Rapid Change, Appendix B (Natural Gas) at p. 34, https://www.energy.gov/sites/prod/files/2015/09/f26/QER_AppendixB_NaturalGas.pdf (explaining that analysis of basis differentials across the natural gas system provides a metric for assessing infrastructure constraints).

Edison, following a least cost purchasing process would buy gas in the zone where the gas was the least expensive.

Q. Have you analyzed the costs to ratepayers associated with the MVP contract?

A. Yes. I assisted the Applied Economics Clinic ("AEC") in preparing a report, which found that the nominal net-costs of the contract and associated gas supply would total approximately $1.0 billion.[47]

Q. Please provide an overview of the Applied Economics Clinic (AEC) report and your role in preparing that report.

A. I assisted AEC in extracting various daily price series at the Dominion South Point, TETCO M2, Transco Zone 5, and Transco Zone 4 pricing locations over a period of years.

Q. Why did you choose those locations?

A. I chose Dominion South Point and TETCO M2 because those pricing locations correspond to the supply area(s) that the MVP will access. I chose the Transco Zone 5 pricing location because that is the terminus of the MVP line. I chose the Transco Zone 4 location because that is the location where Con Edison can also buy gas into its Transco capacity to New York and because it is the alternate source of gas for Con Edison's Transco capacity (i.e., as mentioned above, the prices at the terminus of MVP in Zone 5 would have to compete with prices at Zone 4 (and/or Zone 6) to be purchased by Con Edison or other market participants).

---

[47] *See* Exhibit __ (GL-4).

Q. Have you updated your price analysis since your 2017 work with AEC?

A. Yes.

Q. What have you found?

A. I found that either assuming convergence between Transco Zone 5 and Transco Zone 4, or continued purchase at Zone 4, had the MVP been in-service this year, (i.e., since January 1, 2019 through the end of March), that the value of accessing the average price of the Dominion South Point and TETCO M2 locations (which average price was $2.67/Dth) versus accessing the average price of Transco Zone 4 (which average price was $2.85/Dth) was now only $0.17 versus a cost to access that supply of $0.78[48] per Dth assuming 100% utilization. Thus with a "savings" of $0.17 and a cost of that "savings" of $0.78 makes the net-cost $0.61 per Dth per day. For a full year, this equates to $55.66 million dollars of net costs when considering the fixed costs of MVP at what is estimated to be an anchor shipper rate. Over the course of the twenty-year contract, assuming this price relationship persisted, the net cost to ratepayers would equate to $1.11 billion in 2019 dollars.

Q. Is there a reliability justification for the Company to enter into the MVP contract?

A. No. The MVP contract does not relieve or eliminate the Company's citygate capacity needs. There is not a reliability justification for the MVP contract

[48] The $0.78 per Dth per day is the assumed rate that Con Edison will pay under its negotiated rate contract given Con Edison's anchor shipper status.

because the Company could simply use its other existing contracts to move the gas it buys into Transco to its citygate.

Q. Does the twenty-year contract period provide the Company with additional certainty that could justify its decision to enter into the contract?

A. With respect to gas price certainty, no—not without a long-term fixed price supply contract. Absent such a contract (which I am not recommending and which is contrary to Con Edison's contracting processes that I am aware of), Con Edison will be paying the market price for gas whether it purchases at the origin of MVP or into Transco at one or another zone of Transco. The only certainty that I can see is the certainty that ratepayers will bear the cost of an unneeded feeder line to Transco that Con Edison shareholders will benefit from.

Q. Do you have a suggested approach to address the concerns you have regarding the commitment to the MVP pipeline?

A. Yes. Customers should be protected from the commitment to unnecessary fixed costs, and I recommend that the Commission not allow Con Edison recovery of contracted reservation charges for the MVP capacity at all. Instead, the Commission should allow (i.e., limit) recovery of gas (and capacity) costs (for those Dth acquired through MVP) to the lesser of prices reported for Transco Zone 4, Transco Zone 5 or Transco Zone 6, all of which are pricing hubs available to Con Edison on its current Transco capacity and which can receive MVP supplies (i.e., in Zone 5). In this way ratepayers are not saddled with the fixed costs and instead are indifferent to Con Edison's decision with respect to

MVP, as ratepayers would bear gas costs no higher than if Con Edison had not subscribed to MVP.

Q. Please provide an example of your approach would work in practice.

A. If the variable cost of gas received into MVP and delivered to Transco Zone 5 for onward transportation to NYC were $2.50 per Dth and the Transco Zone 4 (or Zone 6) price (the alternative price for a Dth of gas able to be transported to NYC) were $2.75, then Con Edison would be allowed recovery of $2.75 (i.e., comprised of the $2.50 of variable cost plus $0.25 to be used by Con Edison to offset fixed costs). Note of course that pursuant to the planning refinements I outline below, the decision to receive the "$2.75/Dth" gas would still have to be governed by least cost purchasing in that the "$2.75" price was the next highest price in Con Edison's "dispatch stack"[49] considering all the other supplies available to meet the demand on Con Edison able to be served by Transco.

Q. Please explain why your suggested approach is reasonable.

A. My approach seeks to address the increased fixed cost burden to customers. To the extent cost recovery for that decision is sought by the Company, my recommendation would ensure that ratepayers are shielded by means of a hold harmless/indifference metric related to cost recovery. In other words, ratepayers are indifferent to the Company's decision.

[49] Here "dispatch stack" refers to the daily dispatch or daily choice of supplies based upon the Company's variable costs from least cost (when measured at the citygate) to highest cost (again measured at the citygate).

V. Suggested Improvements to Gas Supply Planning

Q. Please provide an overview of the current gas supply planning process in New York.

A. It is my understanding that the Commission opens a docket every year in order to examine each gas utility's supply plans. As explained by Con Edison, these proceedings contain "myriad redacted material filed by all gas utilities…in response to Staff's inquiries regarding various gas supply matters, including expected portfolio changes over the next five years; supply diversity and price risk management; evolving market conditions; and impacts on customer bills."[50]

Q. Have you reviewed the Company's most recent gas supply submittal in Case No. 18-M-0272?

A. Yes, I have reviewed the Company's July 16, 2018 response to Staff's Winter Supply Review Data Request, attached to my testimony as Exhibit __ (GL-6), and the various updates and reports submitted by the Company in that same proceeding.

Q. Please detail your concerns with the Company's submittal.

A. My first observation is that there is a significant amount of redacted material in the Company's submission. While some of this information may be redacted to protect a legitimate confidential business need (like prices under future period supply agreements, the state of negotiations with prospective suppliers and/or which Asset Management Agreements ("AMAs") the Company is considering),

---

[50] Exhibit __ (GL-5) at page 1.

there are other examples where the information should be made public. Examples of information which ***should*** be made public include:

1) Existing AMAs (redacted as to pricing);

2) The principles used by the Company to pursue capacity expansions;

3) The numbers of requests for conversion to natural gas and the results of these requests;

4) The capacity allocation percentages for mandatory capacity release to marketers;

5) Pending system expansions;

6) The types of contracts the Companies have entered into which are designed to ensure reliable service to firm customers under winter conditions;

7) The extent of planned reliance on firm gas, spot gas, swing gas, etc.;

8) The liquid points at which the Company typically purchases;

9) The Company's strategy for using storage assets going forward in light of Marcellus area production;

10) The internal reporting, oversight and audit structure of the Company's hedging program;

11) How the Company's use of local production/landfill/renewable gas has changed over the course of the past year;

12) A discussion of the impacts of the convergence of the gas and electric markets in the Company's service territory, including an increase (or

decrease) in summer load from prior year and how gas-fired electric generators' needs and behavior during prior winter impacted distribution system operations;

13) A list of all electric generators in the Company's service territory, and whether or not they are attached to the Company's distribution system;

14) Typical communications between gas-fired generators and the Company's natural gas control center and any improvements planned for those communications; and

15) How much natural gas is being sold on an annual basis for use in natural gas vehicles and how this has changed over the past few years.

Q. Why should this information be made public?

A. None of these topics contain competitively sensitive information. Where such concerns are not present, the Commission should recognize the countervailing interest that access to information in regulatory proceedings is vital to the conduct of a proceeding and underscores the integrity of the Commission process at issue.

Q. If the Commission were to decline to adopt your recommendation to make this information public, is there another approach that in your opinion might improve the gas supply planning review process?

A. At a minimum, and as I discuss below, a process should be established to allow intervenors to execute non-disclosure agreements in order to access the above cited materials and to comment on that information as appropriate.

Q. Do you have any additional concerns regarding these annual gas supply review proceedings?

A. Yes. Although the Commission has broad discretion to review the long-range programs of gas utilities,[51] the Commission historically has not made any formal public findings regarding the sufficiency of each gas utility's supply plan in these proceedings. Rather, it seems to be just a process between the utility and DPS Staff. Moreover, there is no connection between what is set forth in these planning documents and what customers ultimately will be asked to pay. Intervenors historically have not had discovery rights in these proceedings and there are no transcribed, on the record, technical conferences, let alone a formal evidentiary hearing.

Q. How does this process in New York compare to other state commissions' review of gas utility supply plans, of which you are aware?

A. At present, based upon my knowledge, there is no "perfect" state process. However, there are several states which require submissions of data, which if combined, come close to the type of transparency that could and should be the hallmark of an ideal process. For instance, in North Carolina, Piedmont Natural Gas files historic and projected load duration curves and against such curves presents its "resource stack" of pipeline capacity and on-system supplementals

[51] Public Service Law § 5(2) (the Commission has broad discretion to "encourage all persons and corporations subject to its jurisdiction to formulate and carry out long-range programs, individually or cooperatively, for the performance of their public service responsibilities with economy, efficiency, and care for the public safety….").

(e.g., LNG and CNG) to demonstrate its resource sufficiency.[52] In Massachusetts, the utilities present design day demand (net of conservation and energy efficiency) and against that they present their contractual[53] and on-system resource stack and identify surplus or deficit conditions with respect to that matching of forecasted demand to contracted resources.[54] In addition, many utilities that I am aware of also conduct post-winter analyses of peak hourly takes at the take station level and compare these experienced takes to their system model's predictions of takes under the experienced degree day conditions. In many cases this "post-action" analysis coupled with future demand growth projections identifies potential hourly demand versus hourly contracted resource deficits.

Q. In addition to staff's annual review of gas utility supply plans, does the Company engage in additional planning efforts?

---

52 Annual Review of Gas Costs Pursuant to G.S. 62-133.4(c) and Commission Rule R1-17(k)(6), North Carolina Utilities Commission Docket No. G-9, Sub 727, Testimony and Exhibits of Gennifer Raney on behalf of Piedmont Natural Gas Company, Inc. (August 1, 2018), https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=feb95b8f-afe1-4fab-8040-edd252c431a3.

53 Here, contractual includes both utility held pipeline capacity and Delivered Service contracts, the description of the service provided, and the daily quantity available under the contract.

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

A. Yes, the Company issues a Gas Long-Range Plan every few years, typically coinciding with its rate filings.[55] The most recent Gas Long-Range Plan was completed in January 2019.[56] The Company also engages in a 5-year forward planning process for the New York Facilities.[57]

Q. Do these efforts correct the deficiencies you have identified above?

A. No. My understanding is that there is no formal schedule requiring the issuance or filing of the Company's Gas Long Range Plans.[58] There is also no connection between what is set forth in these plans and what customers ultimately will be asked to pay.

Q. Do you have any recommendations to improve the Company's gas supply planning process?

A. Yes, my recommendations fall into three general categories. First, I propose changes to the process by which gas supply issues are addressed. These changes would augment and supplement the current annual Staff review of gas supply plans. Second, I propose changes to how the Commission should review and consider gas supply information. In essence, the Company would be required to submit a long range plan, which would form the basis for future cost recovery in a gas cost reconciliation proceeding. Third, I propose changes to the types of

---

[55] Exhibit __ (GL-2) at page 2.

[56] https://www.coned.com/-/media/files/coned/documents/our-energy-future/our-energy-projects/gas-long-range-plan.pdf.

[57] Con Edison Response to DPS-37 (April 26, 2019).

[58] Exhibit __ (GL-2).

information that the Company should submit to better inform gas supply decision making.

Q. Please explain your first category of changes to the process by which gas supply issues are addressed.

A. First of all, the process should, for the next five years at least, be an annual process. It should be an open process with intervenors having discovery rights, and to the extent it is more administratively efficient to have a series of technical conferences (following discovery), then those should be transcribed. If needed, an evidentiary hearing should be established. As the Commission has recently acknowledged, "[g]as supply constraint solutions will need to involve greater visibility of the distribution planning process to stakeholders and local communities, to enable joint problem solving."[59]

Q. Please explain your second category of changes to how the Commission should review and consider gas supply information.

A. As a starting place, the Company should submit a long-range plan, which would set forth projections of demand, by peak hour by Con Edison operational "division" and by day by "division." Against that demand, the resources to meet that demand should be set based upon the contracts and the on-system supply capabilities of the Company. The Company should then identify the cost of each

[59] *Petition of Consolidated Edison Company of New York, Inc. for Approval of the Smart Solutions for Natural Gas Customers Program*, Case No. 17-G-0606 at 35, Order Approving with Modification the Non-Pipeline Solutions Portfolio (February 7, 2019).

resource (fixed cost and projected[60] or known[61] variable costs) and the projected load factor utilization of the resources so that all-in costs can be reviewed and alternatives that might result in lower all-in cost be evaluated.

Q. Once the Company submits a long range plan, what would follow?

A. An agreed-upon long range plan would become the basis for both the annual gas cost reconciliation proceedings and for rate case revenue requirement development. In the annual gas cost reconciliation proceedings, the long range plan would provide the baseline. Differences between the baseline and the actuals in the gas cost reconciliation proceeding would be evaluated as "variances from plan." This is in contrast to the Commission having to review the gas cost reconciliation proceedings with information, resources, structures, and costs that may not have been revealed previously.

Q. Please explain what you mean by "all-in cost."

A. The "all-in cost" is determined by looking at the annual facilities'/fixed costs plus commodity/O&M cost per unit of demand met taking into account the load factor of the annual demand to be met. Below I provide an example of "all-in" cost calculations.

---

[60] Here, "projected" would be in those cases where future costs are based upon market indices and projections of those future values.

[61] Here, "known" would exclude instances where negotiations have not been completed or where revealing "known" would impact negotiations for similarly situated transactions.

	Annual Facilities' / Fixed Costs	Annual O&M / Commodity Costs	Peak Hour Demand (Dth/Hr)	Annual Incremental Demand Met	All-in Cost ($/Dth)
Ex. 1	$5,000,000	$1,800,000	1,000	150,000	$45.33
Ex. 2	$15,768,000	$420,000	1,000	150,000	$107.92

Ex. 1 Assumptions: Annual Cost of CNG Facility is $5 MM; CNG $/Dth $12;
Ex. 2 Assumptions: Annual Cost of New build PL Capacity at $1.80/Dthd; $/Dth $2.80;

Common Asssumptions: 1,000 Dth/Hr (24,000 Dthd); and 150 Hours/Yr Equivalent Full use.

Q. Are you saying that the figures above are representative of actual costs that Con Edison might incur?

A. Not necessarily. This is an illustrative example demonstrating how the Company would calculate the "all in" cost of various alternatives.

Q. Please explain your third category of changes as to the types of information that the Company should submit.

A. I recommend the Company file the material it files today in the gas supply planning dockets reviewed by Staff, a long range plan as outlined above, and the following:

1) Historic daily winter period demand curves for the prior 5 years by class along with the prior demand forecasts for the same periods;
2) Historic daily non-winter period demand curves for the prior 5 years by class along with the prior demand forecasts for the same periods;
3) Historic system winter period demand curves, (hourly and daily) for each of the Company's take stations for the prior five years along with the demand forecasts for the same periods;

4) Historic system non-winter period demand curves, (hourly and daily) for each of the Company's take stations for the prior five years along with the demand forecasts for the same periods;

5) The historic resource stacks of the Company employed to meet those historic demand curves;[62]

6) The Company's forecasted winter period system demand duration curves for the next five years;

7) The Company's forecasted non-winter period system demand duration curves for the next five years;

8) The Company's forecasted winter period demand curves, (hourly and daily) for each of the Company's take stations;

9) The Company's forecasted non-winter period demand curves, (hourly and daily) for each of the Company's take stations;

10) The resource stacks (including separate presentation of their respective fixed and projected variable costs and projected load factor utilization) the Company has under contract to meet the Company's forecasted forward period demand curves;[63] and

---

[62] Note that for the hourly resources by take station, the Company should indicate a) its hourly contract rights, b) any overrun services it received to meet hourly demands; and c) Company-operated facilities employed to meet demands not otherwise met by contract rights or overruns service(s). In addition, the Company should note the extent to which delivered services (either to the Company or for the benefit of the Company's transportation customers) contributed to meeting demands by take station.

[63] Note that for the hourly resources, by take station, the Company should indicate then-existing contract rights and Company-operated facilities' hourly (and total)

11) For those forecasted demands not met by existing contract rights plus Company-operated facilities, the Company should identify all potential resources (including non-pipeline solutions) under consideration and each such resource's forecasted all-in cost (as defined above) and provide the detailed analysis and assumptions used for the build-up of such resources' all-in costs presented by the Company. In addition, the Company should identify potential non-pipeline solutions not under consideration for each forecasted period, and the detailed analysis performed as to why the particular potential non-pipeline solutions are not under consideration for the subject period(s).

Q. How would this information assist the Commission?

A. The historic information would be used to evaluate previously forecasted demands to actual realized demands and the resources used to meet those actual demands. The forecasted demand information would identify gaps, if any, between forecasted demands and resources. The presentation of potential resources, their timing, all-in costs, and capabilities would assist the Commission in both understanding the available alternatives and the trade-offs involved with each. I recommend that the culmination of this planning, presentation and consensus building process be Commission approval, based on a traditional review of reasonableness.

capabilities to be employed to meet forecasted demands not met by take station contract rights. In addition, the Company should note the extent to which delivered services (either to the Company or for the benefit of the Company's transportation customers) contributed to meeting demands by take station.

Lastly, the consensus resource stack on contracts, costs and capabilities would form the baseline against which subsequent gas reconciliation proceedings are conducted and against which variances from plan are identified and worked through. In this way, hopefully there are no future surprises like those of the recent past nor are there situations where the first time the Commission reviews a new resource, the cost recovery of which is sought in a gas reconciliation case. This will be because the alternatives were under review and part of the consensus planning process.

Q. Have similar refinements been presented to other state commissions?

A. Yes. In Rhode Island, the Public Utilities Commission's Division of Public Utilities and Carriers (i.e., the Staff) and its gas utility, Narragansett Electric Company (a National Grid company) have submitted to the Rhode Island Public Utilities Commission a substantially similar baseline planning process to form the basis of both an approved plan and subsequent fuel factor reviews. A copy of the submittal outlining the proposed process is attached as Exhibit __ (GL-8).

Q. How do these refinements correct the deficiencies you have identified above?

A. A more robust planning process would lead to multiple benefits, including: (1) identifying potential issues well in advance of experiencing demand/supply mismatches requiring moratoria; (2) a way to manage and contain the fixed cost commitments made by the Company, which will protect ratepayers against unreasonable financial risk and protect the Company against prudency risk from after-the-fact regulatory challenges; and (3) a more thorough framework for the Company to consider alternatives that would have lower all-in costs to customers.

Q. Does this conclude your testimony?

A. Yes.

Exhibit __ (GL-1):
CV and List of Expert Testimony
of Gregory M. Lander

Greg Lander, President
Skipping Stone LLC

Professional Summary:

As President of Skipping Stone Inc., Greg Lander is responsible for Strategic Consulting in the mergers and acquisition arena with numerous clients within the energy industry. Generally recognized in the energy industry as an expert, he has advised and/or given testimony at numerous Federal Energy Regulatory Commission (FERC), State, arbitration, and legal proceedings on behalf of clients and has advised as well as initiated standards formation before the Gas Industry Standards Board (GISB) (predecessor to the North American Energy Standards Board (NAESB)). As Founder, President, and Chief Technology Officer of TransCapacity Limited Partnership, he was responsible for conceiving, planning, managing, and designing Transaction Coordination Systems utilizing Electronic Data Interchange (EDI) between trading partners. As a founding member of GISB, he assisted in establishing protocols and standards within the Business Practices, Interpretations and Triage Subcommittees.

Professional Accomplishments:

- Handled all Due Diligence for purchaser (Loews Corp) in acquisitions of two interstate pipelines, one natural gas storage complex, and ethylene distribution and transmission systems (Texas Gas Transmission, Gulf South Pipeline, Petal Storage, Petrologistics, and Chevron Ethylene Pipeline) most in excess of $1 Billion. Developed purchaser's business case model, including rate/revenue models, forward contract renewal models, export basis modeling and revenue models, and operating cost and capex models. Coordinated Engineering and Environmental Due Diligence Teams integrating findings and assessments into final Diligence Reports.
- Assisted major electric retailer in 9 states with business case development for entry into North Eastern U.S. Commercial & Industrial natural gas marketing business. Identified market share of incumbents; retail registration process, billing processes; utility data exchange rules and procedures and developed estimates of addressable market by utility.
- Handled all economic Due Diligence for purchaser of large minority stake in Southern Star Gas Pipeline. Developed purchaser's business case model, including rate/revenue models and forward contract renewal models, assessed potential competitive by-pass of asset located in "pipeline alley", developed revenue models and operating cost and capex models. Coordinated Engineering, Pipeline Integrity, and Environmental Due Diligence Teams integrating findings and assessments into final Diligence Reports.
- Developed post-acquisition integration plans for inter-operability and alterations to system operations to take advantage of opportunities presented by

synergistic facilities' locations and functions and complimentary contractual requirements. Implementation of plan resulted in fundamental changes to systems operations and improvement in systems, net revenues, capacity capabilities, and facilities utilization.

- Handled all economic analysis, modeling, and systems capability due diligence for potential purchaser in several preliminary or completed yet un-consummated pre-transaction investigations involving Panhandle Eastern, Northern Border, Bear Paw, Florida Gas, Transwestern, Great Lakes, Guardian, Midwestern, Viking, Southern Star, Columbia Gas, Midla, Targa (No. Texas), Ozark, ANR, Falcon Gas Storage, Tres Palacios, Rockies Express, Norse Pipelines, Southern Pines, Leaf River, LDH (Mont Belvieu), Kinder Morgan Interstate, Trailblazer, Rockies Express and South Carolina Gas Transmission.
- Post Texas Gas Transmission and Gulf South Pipe Line acquisitions, assisted with all investigations involving assessments and proposals for realizing potential synergies with/from asset portfolio; rate case strategy development and alternate case development; and strategies around contract renewal challenges.
- Headed up due diligence team in acquisition of multi-state retail (residential) natural gas and electric book by Commerce Energy.
- Headed up due diligence team in acquisition of multi-state retail (C&I) natural gas book by Commerce Energy.
- Served as lead consultant for consortium of end-users, Local Distribution Companies, Power Generators, and municipalities in several major FERC Rate Cases, service restructuring, and capacity allocation proceedings involving a major Southwestern U.S. Pipeline.
- Served as lead consultant and expert witness for consortium of end-users, Local Distribution Companies, Power Generators, and municipalities in major FERC rate case under litigation involving decades-long disputes over service levels, cost allocation, and rate levels.
- Served as lead consultant for consortium of end-users and municipalities in major FERC rate case involving implementation of proposed rate design, cost allocation, and rate level changes.
- Expert witness in numerous gas and electric utility rate cases; integrated resource plans; litigated service offerings and cost approval and allocation proceedings for public interest clients. Controversies, often involving hundreds of millions to billions of dollars over cases' time horizons, are common.
- Developed and critiqued Rate Case Models for several pipeline proceedings and proposed proceedings (as consultant variously to both pipeline and shippers). Activities included modeling (and critiquing) new services' rates, costs, and revenues; responsibilities included development of various alternative cost allocation/rate designs and related service delivery scenarios.

- Handled all market assessment, forward basis research, and transportation competition modeling for several proposed major pipelines and laterals, including two $1 Billion+ Greenfields projects that went into construction and operation providing new outlets for growing southwestern shale production. (Gulf Crossing and Fayetteville Lateral).
- Assessed supply and demand balance for Southwestern US (OK, TX, Gulf Coast and LA) including assessment of future demand and supply displacement associated with West Texas wind power development and its likely impact on pipeline export capacity from region.
- Assessed supply and demand balance for Northeast to Gulf Coast capacity additions including assessment of Gulf Coast demand and export growth and its likely impact on forward basis.
- Assessed start-up gas supply needs for Appalachian coal fired power plant, resulting in installation of on-site LNG storage and gasification to address lack of enough firm pipeline capacity to meet need.
- Assessed installed and projected wind-turbine capacity in ERCOT and its eventual impact on Texas electric market as wind power output approaches minimum ERCOT load levels.
- Designed and developed EDI based data collection system, data warehouse and web-based delivery system (www.capacitycenter.com) for delivering capacity data collected from pipelines to shippers, marketers, traders, and others interested in capacity information to support business operations and risk-management requirements.
- Assisted client in developing proposals to increase pipeline capacity responsiveness and proposed market fixes that would create price signals around sub-day non-ratable flows, including rate proposals, sub-day capacity release markets, and measures to address advance reservation of capacity for electric generation fuel to meet sub-day generation demands.
- Developed “universal capacity contract” data model for storage of all interstate capacity contract transactions from all interstates in single database.
- Led design effort culminating in FERC-mandated datasets defining pipeline capacity rights, (including receipt capacity, mainline capacity, delivery capacity, segmentation rights, in and out of path capacity rights), Operationally Available Capacity, Index of Customers, and Transactional Capacity Reports (through GISB).
- Assembled consortium of utilities to investigate and develop large high-deliverability salt storage cavern in desert southwest (Desert Crossing). As LLC’s Acting Manager, was responsible for developing business case and economic models; handling all partner issues and reporting; coordinating all field engineering, facilities design, planning and siting; and managing all environmental, legal, engineering and regulatory activities. Wrote FERC Tariff. Brought project to NEPA Pre-Filing Stage and conducted non-binding Open

Season, as well as assisted with prospective shipper negotiations. Project cancelled due to 2001 "California Energy Crisis" and contemporaneous Enron and energy trading sector implosions.

- Designed comprehensive retail energy transaction and customer acquisition data model, process flow, and transaction repository for web-based customer acquisition and customer enrollment intermediary.
- Experienced in negotiation and drafting (from both seller side and buyer side) of firm supply, firm transportation, firm storage, and power supply and capacity agreements for numerous entities including project financed IPPs and for new greenfield pipeline and expansion of storage system.
- Provided market entry assessment for large international manufacturing and service company seeking to enter U.S. micro-grid, combined heat and power, and integrated solar, gas & battery markets.
- Conducted interstate pipeline capacity utilization analysis for New England following winter of 2013/2014 price fly-up.
- Conducted PJM East interstate gas pipeline capacity utilization and comparative analysis between pipelines with standard NAESB nominating cycles versus those with near hourly scheduling practices.
- Conducted requirements analysis for several firms pursuing software selection of energy transaction systems.
- Instrumental in the formation of the GISB. Member of industry team that lead the development of the proposal for and bylaw changes related to the formation of NAESB.
- Provided support to numerous clients and clients' attorneys in disputes involving capacity contracts, capacity rights allocations, tariffs, rate cases, intellectual property rights cases, and supply contract proceedings as both up-front and behind the scenes expert.

Associations and Affiliations:

Longest serving Member of Board of Directors for NAESB and prior to that GISB – 23 years.

GISB Committees: Former Chairman, Business Practices Subcommittee – drafted approximately 450+ initial industry standards that are now codified FERC regulations (Order 567); Former Chairman, Interpretations Subcommittee – drafted and led adoption process for first 50+ standards interpretations; Former Chairman, Triage Subcommittee; Title Transfer Tracking Task Force; Order 637 GISB Action Subcommittee; and industry Common Codes Subcommittee. Currently member of NAESB Wholesale Gas Quadrant Executive Committee and of NAESB Parliamentary Committee

Past and Affiliations and Associated Accomplishments:

1981-1989: One of five initial employees of Citizens Energy Corporation, Boston Mass. Responsible for starting and growing Citizens Gas Supply, one of the first independent gas marketers of the early 1980's, into $200MM+ annual operation. Successfully lobbied for pipeline Open Access (Orders 436 and 636), introduction of pipeline Affiliated Marketer rules of conduct (Order 497), and Open Access to pipeline operational information (Order 563).

1989-1993: Independent Consultant - Natural Gas Projects, Pipeline Rate Cases, Project Financed Contract negotiations, and Independent Power markets

1993 – 1999: Founder and President, TransCapacity Service Corp – Software products and services related to pipeline capacity trading, nomination, and contracting. Raised $17 MM from industry player to establish TransCapacity. Successfully lobbied for Pipeline restructuring and formation of capacity release market (Order 636). Sold to Skipping Stone.

1999 – 2004: Principal and Partner, Skipping Stone – Energy market consultants

2004 – 2008: President of Skipping Stone following purchase of Skipping Stone by Commerce Energy, Inc.

2008: Repurchased Skipping Stone from Commerce Energy, Reformulated Skipping Stone as LLC with Peter Weigand

2008 to Present: President and Partner, Skipping Stone. In addition to handling book of clients, responsible for all Banking, Accounting, Operations, Risk Management and contract matters for Skipping Stone.

Education:

1977: Hampshire College, Amherst, MA; Bachelor of Arts

Publication:

2013: Synchronizing Gas & Power Markets - Solutions White Paper

Expert Testimony of Gregory M. Lander

Name of Case	Jurisdiction	Docket Number	Date
El Paso Natural Gas Company	Federal Energy Regulatory Commission	RP04-251-000	May 3, 2004 (Testimony)
El Paso Natural Gas Company	Federal Energy Regulatory Commission	RP08-426-000	May 19, 2009 (Answering Testimony) June 2, 2010 (Supplemental Answering Testimony)
El Paso Natural Gas Company	Federal Energy Regulatory Commission	RP10-1398-000	June 28, 2011 (Answering Testimony) March 4, 2014 (Answering Testimony)
Petition of Boston Gas Company and Colonial Gas Company, each d/b/a National Grid for Approval by the Department of Public Utilities for a Firm Transportation Contract with Algonquin Gas Transmission Company	Massachusetts Department of Public Utilities	13-157	December 12, 2013 (Direct Testimony)
Petition of Boston Gas Company d/b/a National Grid for Approval by the Department of Public Utilities of a twenty-year Firm Transportation Agreement with Tennessee Gas Pipeline Company, involving an expansion of Tennessee's interstate pipeline running from Wright, New York to	Massachusetts Department of Public Utilities	15-34	June 5, 2015 (Direct Testimony)

Dracut, Massachusetts, known at the Northeast Energy Direct Project			
Petition of Bay State Gas Company d/b/a Columbia Gas of Massachusetts for Approval by the Department of Public Utilities of a twenty-year Firm Transportation Agreement with Tennessee Gas Pipeline Company, involving an expansion of Tennessee's interstate pipeline running from Wright, New York to Dracut, Massachusetts, known at the Northeast Energy Direct Project	Massachusetts Department of Public Utilities	15-39	June 5, 2015 (Direct Testimony)
Petition of The Berkshire Gas Company for Approval of a Precedent Agreement with Tennessee Gas Pipeline Company, LLC, pursuant to G.L. c. 164, § 94A	Massachusetts Department of Public Utilities	15-48	June 5, 2015 (Direct Testimony)
Investigation of Parameters for Exercising Authority Pursuant to Maine Energy Cost Reduction Act, 35-A M.R.S.A. Section 1901	Maine Public Utilities Commission	2014-00071	July 11, 2014 (Direct Testimony)
Virginia Electric and Power Company's Integrated Resource Plan filing pursuant to Va. Code § 56-597 *et seq*.	Virginia Corporation Commission	PUR-2017-00051	August 11, 2017 (Direct Testimony)
In the Matter of the Laclede Gas Company's Request to Increase Its Revenues for Gas Service In the Matter of the Laclede Gas Company	Missouri Public Service Commission	File No. GR-2017-0215 File No. GR-2017-0216 (Consolidated)	September 8, 2017 (Direct Testimony) November 21, 2017 (Surrebuttal Testimony)

d/b/a Missouri Gas Energy's Request to Increase Its Revenues for Gas Service			
Application of San Diego Gas & Electric Company (U902M) for Authority, Among Other Things, to Update its Electric and Gas Revenue Requirement and Base Rates Effective on January 1, 2019. Application of Southern California Gas Company (U904G) for Authority, Among Other Things, to Update its Gas Revenue Requirement and Base Rates Effective on January 1, 2019.	California Public Utilities Commission	Application 17-10-007 Application 17-10-008 (Consolidated)	May 14, 2018 (Direct Testimony) June 8, 2018 (Rebuttal Testimony)
Application of Virginia Electric and Power Company to revise its fuel factor pursuant to § 56-249.6 of the Code of Virginia	Virginia State Corporation Commission	PUR-2018-00067	June 14, 2018 (Direct Testimony)
Application of Southern California Gas Company (U 904 G) and San Diego Gas & Electric Company (U 902 G) Regarding Feasibility of Incorporating Advanced Meter Data Into the Core Balancing Process	California Public Utilities Commission	Application 17-10-002	July 2, 2018 (Direct Testimony)
Virginia Electric and Power Company's Integrated Resource Plan filing pursuant to Va. Code § 56-597 *et seq*.	Virginia Corporation Commission	PUR-2018-00065	August 13, 2018 (Direct Testimony)
In the Matter of Constellation Mystic Power, LLC	Federal Energy Regulatory Commission	ER18-1639	August 23, 2018 (Answering Testimony) September 4, 2018 (Cross Answering

			Testimony)
South Carolina Electric and Gas Company Application for Approval of Merger with Dominion Resources	South Carolina Public Service Commission	2017-370-E; 2017-305-E; and 2017-207-E	September 24, 2018 (Direct Testimony)
In re: Annual Review of Base Rates for Fuel Costs of South Carolina Electric and Gas Company	South Carolina Public Service Commission	2019-2-E	March 19, 2019 (Direct Testimony)

Exhibit __ (GL-2):

Con Edison Response to EDF-1-2; Case No. 17-G-0606

Company Name: Con Edison
Case Description: Con Edison Smart Solutions for NGC Customers
Case: 17-G-0606

Response to EDF Interrogatories – Set EDF-1
Date of Response: February 13, 2019
Responding Witness: Kathleen Trischitta, Christine Cummings

Question No. : 2

Please refer to the Company's Long-Term Gas Supply Plan from December 2010, available at http://158.57.189.31/publicissues/PDF/GLRP1210c.pdf.

a. Is this 2010 Long-Term Gas Supply Plan the most recent plan drafted by the Company? If no, please provide the Company's most recent Long-Term Gas Supply Plan.

b. Does the Company draft a Long-Term Gas Supply Plan each year? If no, please explain how frequently the Company drafts a Long-Term Gas Supply Plan.

c. Please refer to page 91, which states: "Con Edison recognizes that there is a need for the construction of new interstate pipeline capacity to serve growing demand for natural gas in the New York metropolitan area. Given the high utilization level of existing interstate pipeline capacity in the region, new pipeline capacity must be developed. Con Edison supports the construction of new interstate pipeline capacity." Please detail any and all actions Con Edison has taken since 2010 to address this identified need.

d. Section 5(2) of the Public Service Law provides that "The commission shall encourage all persons and corporations subject to its jurisdiction to formulate and carry out long-range programs, individually or cooperatively, for the performance of their public service responsibilities with economy, efficiency, and care for the public safety, the preservation of environmental values and the conservation of natural resources." Does the Long-Term Gas Supply Plan consider the state's policy of achieving 80% greenhouse gas reductions compared to a 1990 baseline by 2050, which was adopted by executive order in 2009? If so, how? If not, why not?

RESPONSE:

a) The Company's most recent Gas Long-Range Plan was completed in January 2019. The latest plan can be found at the following link:

https://www.coned.com/-/media/files/coned/documents/our-energy-future/our-energy-projects/gas-long-range-plan.pdf.

b) The Company has issued its Gas Long-Range Plans every few years since 2010, which typically coincides with our rate filings.

c) The Company contracted for service on a new pipeline project in November of 2013, the Spectra NJ-NY expansion project, which included the creation of a new citygate delivery point in Lower Manhattan. Since then, when available, the Company has entered into service agreements with pipelines for pipeline capacity that has been turned back and not renewed by other existing capacity holders. In addition, please see response to 1b.for other recent efforts.

d) Yes, the Company's Gas Long-Range Plan considers State and regulatory policy initiatives. The Company examines several planning uncertainties, including evolving regulatory policy, to better understand their potential business implications. Our most current long range plan emphasizes that the Company will help customers pursue alternatives that are cleaner than natural gas.

Exhibit __ (GL-3):

Con Edison Response to EDF-1-1; Case No. 17-G-0606

Company Name: Con Edison
Case Description: Con Edison Smart Solutions for NGC Customers
Case: 17-G-0606

Response to EDF Interrogatories – Set EDF-1
Date of Response: February 13, 2019
Responding Witness: Kathleen Trischitta, Christine Cummings

Question No. : 1

Please refer to the Notice of Temporary Moratorium filed on January 17, 2019, which states: “this temporary moratorium is necessary because there are gas supply constraints in this part of our service territory that limit our ability to meet customer demand on the coldest winter days.”

a. Please provide the date on which Con Edison first identified there would be gas supply constraints in this part of its service territory.

b. Did Con Edison identify gas supply constraints as part of its ten-year supply and capacity planning analysis? If no, please explain why Con Edison did not identify the need for a temporary moratorium in its ten-year supply and capacity planning analysis. If yes, please explain any and all actions Con Edison took to address these constraints.

c. Did Con Edison identify the need for a temporary moratorium in any of its gas utility supply plans submitted in the last three years in Case Nos. 16-M-0263, 17-M-0280, or 18-M-0272? If no, please explain why Con Edison did not identify the need for a temporary moratorium in any of those submissions.

\

d. Please explain how this temporary moratorium complies with Public Service Law Section 30, which provides, “It is hereby declared to be the policy of this state that the continued provision of all or any part of such gas, electric and steam service to all residential customers without unreasonable qualifications or lengthy delays is necessary for the preservation of the health and general welfare and is in the public interest,” and with the Commission’s stated goal of expanding the natural gas system in New York State.

RESPONSE:

a) The Company publicly identified the potential for gas supply constraints on September 19, 2016 when the joint proposal became public in Case 16-G-0061. The Joint Proposal provides for a peak demand reduction collaborative and that this collaborative will "examine the potential impact that delays of upstream interstate pipeline construction may have on meeting growing demand associated with oil-to-gas conversions and new business." The Company notes that EDF participated in the settlement discussions that led to this joint proposal and that EDF is a party to this proposal.

b) Yes, the Company identifies the need for new gas pipeline capacity as part of its annual capacity planning process. The Company identified an additional need in 2014 and began discussions with developers for new pipeline capacity to its service territory.

   After the New York State Department of Environmental Conservation denial of Constitution Pipeline's state water permit on April 22, 2016, pipeline developers became increasingly concerned about doing business in New York. As a result, the Company recognized increasing uncertainty about its ability to negotiate precedent agreements with pipeline developers for projects that would ultimately require approval from federal, state and local agencies.

   After working with the gas peak demand reduction collaborative for almost a year, the Company filed its Smart Solutions programs in September 2017 to develop alternative solutions to meet growing gas peak demand. The Company recognized the importance of considering alternatives to traditional pipeline service and the need to develop clean energy alternatives for its customers. The Company did not, at that time, know how the market would respond to its initiatives, and the market is still in its infancy.

   Since then, the Company has received several approvals for its Smart Solutions proposals, including to double its energy efficiency efforts and launch a pilot demand response program. The Commission has also approved the Company's non-pipeline RFP filing as modified on February 7, 2019. While the Commission has approved these proposals, the programs are insufficient to avoid the need for a moratorium. Moreover, the implementation success and timing of the programs is not certain.

   In parallel, the Company has been continuing to work with pipeline developers to design projects with minimal impacts to the environment. These projects are intended to focus on maximizing the use of existing infrastructure while limiting the need for significant build out. The purpose of smaller, less complex project design is to increase the likelihood of both reaching mutually agreeable precedent agreement terms with developers and the projects' ability to meet federal, state and local requirements. The success of any of these initiatives remains uncertain.

c) Yes, the Company identified the potential need for a temporary moratorium in its 18-M-0272 submittal.

In the Smart Solutions for Gas Customers Petition filed on September 29, 2017, CECONY stated "the Company forecasts that in the near term it may be unable to meet demand from new customers on extremely cold days, resulting in the need to institute moratoriums on attaching new firm gas customers in areas where pipeline capacity is severely constrained." **In a supplemental May 4, 2018 filing in that proceeding, CECONY stated that it "has previously mentioned that temporary moratoriums are a possibility and is increasingly concerned that they will be necessary. As stated in that proceeding, CECONY believes that moratoriums may be necessary in the near term but it currently cannot state when and where it would institute moratoriums.** CECONY notes, however, that it recently ended its Area Growth Program for Westchester, due to both the lack of interest and pipeline constraints. CECONY cannot predict at this time when and where moratoriums may be necessary because it is currently: (1) evaluating responses to its market solicitation for Non-Pipeline Solutions; and (2) updating planning with National Grid for the jointly owned New York Facilities system. After CECONY has completed these two items it will have the information it needs to determine when and where temporary moratoriums may be needed.

d) The Company objects to this question as calling for a legal conclusion. Notwithstanding this objection, the Company's Commission approved tariff states that the Company is not required to serve new customers if gas is unavailable.

Exhibit __ (GL-4):

Applied Economics Clinic Report on MVP Pipeline

Ratepayer Impacts of ConEd's 20-Year Shipping Agreement on the Mountain Valley Pipeline

Prepared for the Environmental Defense Fund

Authors:

Rachel Wilson

Tyler Comings

Elizabeth A. Stanton, PhD

September 2017

Table of Contents

Table of Contents 2
Executive Summary 3
I. Shipping Costs on the Mountain Valley Pipeline Will Be Paid for by ConEd Ratepayers 4
II. New Pipeline Capacity Lowers Differences in the Cost of Natural Gas between Regions 5
III. The Value of the Mountain Valley Pipeline Has Declined Over Time 8
IV. Con Ed's MVP Contract Will Result in Higher Costs to Ratepayers 12
V. The MVP Contract Locks Con Edison Customers into Higher Rates for 20 Years 14

Executive Summary

The Mountain Valley Pipeline is a proposed new natural gas pipeline in West Virginia and Virginia, and is intended to bring low-cost natural gas out of the Marcellus and Utica Shales to markets in the Southeast and Mid-Atlantic. In January 2016, three months after the certificate application for the project was filed at the Federal Energy Regulatory Commission, Con Edison Gas Midstream, a non-utility subsidiary of corporate parent Consolidated Edison, Inc., announced that it was acquiring a 12.5 percent ownership interest in Mountain Valley Pipeline. At the same time, Consolidated Edison Company of New York, Inc., a regulated gas and electric utility owned by the same corporate parent, entered into a 20-year transportation agreement for 250,000 dekatherms per day of firm natural gas capacity on the proposed pipeline.

ConEd ratepayers will pay the costs to transport natural gas, while shareholders in Consolidated Edison, Inc. would benefit from any profits earned by the pipeline.

Prior to late-2016, an oversupply of natural gas from the Marcellus/Utica region, combined with constraints on pipeline infrastructure, kept prices in the region reliably cheaper than at Henry Hub in Louisiana—historically the benchmark price for U.S. natural gas. This glut of natural gas in the region has eased over the past year, however, as new pipelines and pipeline expansion projects have enabled this surplus natural gas to reach consumers and led to increasing prices in the Marcellus and lower prices in regions that had not previously had access to this natural gas. This difference in prices between regional pricing hubs is known as the "basis differential." As additional natural gas pipeline capacity became available, basis differentials between regional pricing hubs narrowed appreciably as prices in Appalachia rose and prices at other hubs declined.

Given that the MVP project had already been filed with FERC, ConEd customers would benefit from the diminishing basis differentials resulting from the project, whether or not the utility signed a 20-year transportation contract. Rather than contracting for firm transportation service, ConEd could purchase gas out of the MVP and into Transco Zone 5, using its existing transportation rights on the Transco pipeline to bring that gas to its City Gate. However, because Con Ed has committed its ratepayers to a 20-year transportation contract, the costs of this transportation capacity must be considered when assessing the value to ratepayers. Applied Economic Clinic was asked by the Environmental Defense Fund to determine whether ConEd's transportation contract on the MVP would result in unjust and unreasonable costs to ratepayers. We find that the expected benefit of the MVP was quickly disappearing at the time ConEd signed the transportation contract due to the falling basis differentials between the MVP supply and market regions, which erode the benefits of shipping agreements.

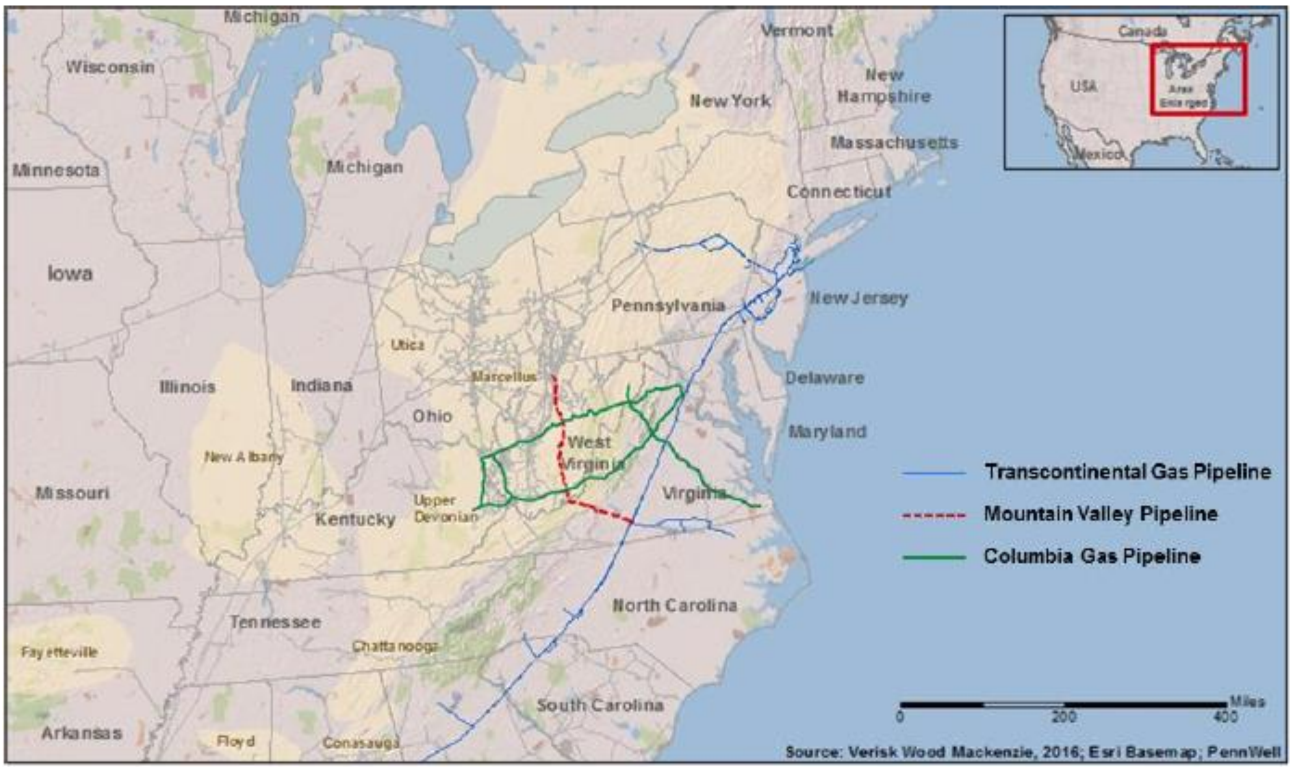
Narrowing basis differentials turned a net present value ratepayer benefit of more than $1 billion into an anticipated $630 million cost given current natural gas pricing.

The nominal costs of ConEd's MVP contract and associated gas supply, which in total will be $1.2 billion over the course of the 20-year agreement, will be shouldered by New York ratepayers, whether or not the pipeline capacity is actually used. As the New York State Public Service Commission evaluates these transportation costs, it should consider Con Ed's ownership interest in this pipeline and the burden of risk that this contract shifts from shareholders to ratepayers.

I. Shipping Costs on the Mountain Valley Pipeline Will Be Paid for by ConEd Ratepayers

The Mountain Valley Pipeline (MVP) is a proposed new natural gas pipeline that would stretch 303 miles from the Equitrans transmission system in Wetzel County, West Virginia to connect to the Transco natural gas pipeline at the Transco Zone 5 compressor station in Pittsylvania County, Virginia.[1] The proposed pipeline route is shown in Figure 1, below.

Figure 1. Mountain Valley Pipeline Route



Source: Wood Mackenzie. 2017. Mid-Atlantic Natural Gas Demand in Support of the Mountain Valley Pipeline Project.

On January 22, 2016, Con Edison Gas Midstream, a non-utility subsidiary of corporate parent Consolidated Edison, Inc., announced that it was acquiring a 12.5 percent ownership interest in Mountain Valley Pipeline, LLC, which is a joint venture between EQT Midstream Partners, LP; NextEra US Gas Assets, LLC; WGL Midstream; and RGC Midstream, LLC.[2] This was Con Edison Gas Midstream's first investment in natural gas infrastructure.[3] On the same day, Consolidated

[1] Mountain Valley Pipeline. 2017. Overview. Available at: https://www.mountainvalleypipeline.info/overview

[2] Mountain Valley Pipeline, LLC. 2016. Mountain Valley Pipeline Secures New Shipper Commitment with Con Edison. News Release.

[3] Con Edison Transmission. 2017. Projects. Available at: http://www.conedtransmission.com/projects.asp

Edison Company of New York, Inc. (ConEd), a regulated utility (owned by the same corporate parent) that provides electric, gas, and steam service in New York City and Westchester County, entered into a 20-year transportation agreement with Mountain Valley Pipeline, LLC for 250,000 dekatherms per day (Dthd) of firm natural gas capacity on the MVP.[4]

These long-term natural gas transportation agreements are important to pipeline developers for two reasons:

- First, pipeline developers typically use these agreements as evidence to the Federal Energy Regulatory Commission (FERC) that there is a need for the project, which must be demonstrated before FERC will grant its approval to build the pipeline. In its application, Mountain Valley Pipeline, LLC stated that "…the increasing natural gas demand by local and regional markets, and the Project shippers' contractual commitments for the entire capacity of the project, are clear evidence of the need for the Mountain Valley Project."[5]
- Second, long-term contracts with shippers, called "anchor" or "foundation" shippers, are also important to pipeline developers as a way to attract financing to fund the project, as they facilitate lenders' confidence that the project's costs will be recovered from shippers and that lenders will be paid the interest on their loaned money.

The existence of long-term transportation agreements for firm natural gas capacity thus aids directly in the construction of new natural gas pipelines by increasing the likelihood of securing both regulatory approval and project financing.

When natural gas begins to travel on a new pipeline, the cost of shipping that gas becomes an operating cost for the capacity purchasing utility. A regulated utility passes that cost, which includes both the actual cost of moving the natural gas as well as a FERC-approved rate of return to the pipeline owners, on to its customers. Pending approval by the New York Public Service Commission, ConEd ratepayers will pay the costs associated with the 20-year transportation agreement on the Mountain Valley Pipeline. Shareholders in Consolidated Edison, Inc., the parent company of ConEd and Con Edison Gas Midstream, would benefit from any profits earned by the pipeline. Any analysis of ConEd's interest in this project must be viewed in light of this affiliate relationship and the potential shifting of risk from shareholders to ratepayers.

II. New Pipeline Capacity Lowers Differences in the Cost of Natural Gas between Regions

In the absence of other significant influences, the construction of new natural gas pipelines would be driven by market demand for, and supply of natural gas, with new pipelines being constructed along paths that would bring large volumes of natural gas supply to areas of high demand. Market inefficiencies or constraints on pipeline capacity lead to regional differences in natural gas prices, which are typically expressed as the difference in natural gas prices between two locations or "hubs." The difference in natural gas prices between two regional hubs is known as the "basis

[4] Mountain Valley Pipeline, LLC. 2016. Mountain Valley Pipeline Secures New Shipper Commitment with Con Edison. News Release.

[5] Mountain Valley Pipeline, LLC. 2015. Application of Mountain Valley Pipeline, LLC for Certificate of Public Convenience and Necessity and Related Authorizations. Docket No. PF15-3-000. Page 10.

differential." The greater the basis differential between regions, the greater the incentive for pipeline developers to construct new capacity to move natural gas from a lower price region into a higher price region. When that new capacity comes online, natural gas prices should both become less volatile and equilibrate as the basis differentials between the supply and the demand regions diminishes. According to the U.S. Department of Energy, shippers that contract for firm transportation service can rely on their contracts "to capture the resulting basis differential. Basis differentials, and how the captured revenues compare to the cost of constructing pipelines, largely determine how much and in which locations pipeline capacity is likely to be added."[6]

This dynamic can be observed in Appalachia, where prices in the region depend on production rates and the availability of natural gas transportation infrastructure. Shippers on the Mountain Valley Pipeline justify their long-term contracts with the argument that they will make it possible to take advantage of cheaper natural gas from the Marcellus and Utica shales once the pipeline is operational. Indeed, an oversupply of natural gas from the region, combined with constraints on pipeline infrastructure, has kept prices in the region reliably cheaper than at Henry Hub in Louisiana—historically the benchmark price for U.S. natural gas. This glut of natural gas in Appalachia has eased over the past year, however, as new pipelines and pipeline expansion projects have enabled this surplus natural gas to reach consumers and led to increasing prices in the Marcellus and lower prices in regions that had not previously had access to this natural gas.

According to the U.S. Energy Information Administration (EIA), the difference between the price of natural gas at Henry Hub and the prices at the various hubs in Appalachia has narrowed as new pipeline projects and expansions have been completed. Prices at Dominion South (in southwestern Pennsylvania) averaged $0.76 per MMBtu lower than Henry Hub in the first seven months of 2016. Between July and December of 2016, more than 3.0 Bcf/d of interregional capacity was added, and the average basis differential between the two hubs dropped to a difference of $0.53 per MMBtu during the first seven months of 2017.[7]

Figure 2, below, presents daily natural gas prices for two price hubs—Dominion South and Henry Hub—from October 2013 through May 2017 and shows a notable tightening of the difference between prices at these hubs, with an obvious convergence of these price points starting in October 2016 following the completion of the Ohio Valley Connector Expansion and the Rockies Express Pipeline Zone 3 expansion.[8] There are 25 additional pipeline projects in development that are scheduled to be completed by the end of 2017, which would add an additional 7.2 Bcf/d of natural gas transportation capacity.[9] If the pipeline capacity expansion keeps pace with, or exceeds, the production of shale gas then one would expect the basis differentials between regions to disappear and the prices of natural gas to equilibrate between regions.

[6] US Department of Energy. 2015. Natural Gas Infrastructure Implications of Increased Demand from the Electric Power Sector. Page 3. Available at: https://energy.gov/sites/prod/files/2015/02/f19/DOE%20Report%20Natural%20Gas%20Infrastructure%20V_02-02.pdf

[7] US Energy Information Administration. 2017. Natural gas pipeline projects lead to smaller price discounts in Appalachian region. Available at: https://www.eia.gov/todayinenergy/detail.php?id=32512

[8] *Id*.

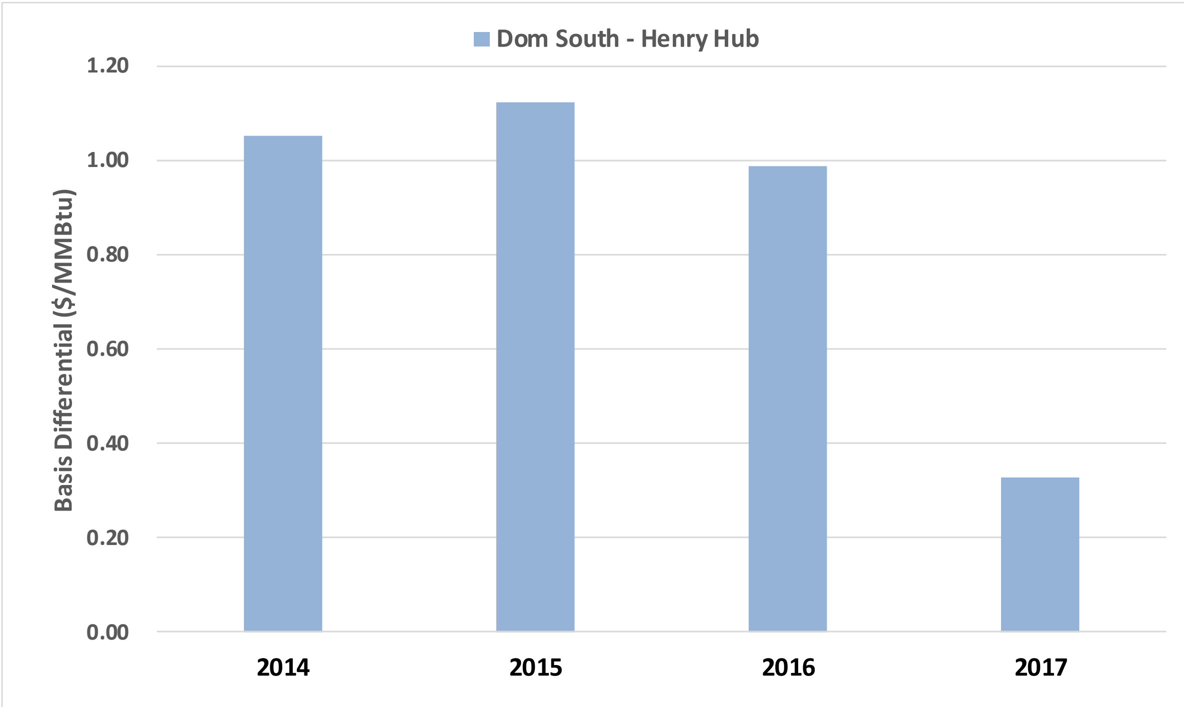
[9] *Id.*

Figure 2: Historical Natural Gas Prices for Dominion South and Henry Hub ($/MMBtu)[10]

The change in annual average basis differentials from 2014 to 2017 (partial year) between Dominion South and Henry Hub is shown in Figure 3.

[10] Natural Gas Intelligence, Historical Daily Prices. (http://www.naturalgasintel.com/)

Figure 3: Basis Differential between Dominion South and Henry Hub ($/MMBtu)[11]



As shown in Figure 3, Dominion South natural gas was more than $1 per MMBtu cheaper than at Henry Hub in 2014, and this basis differential persisted for the next two years. However, with the new pipeline capacity that came online in late 2016 and early 2017, the annual average basis differential between these regions fell by 67 percent. This means that much of Dominion South's previous discount (relative to Henry Hub) for shale gas resulting from oversupply conditions has disappeared.

III. The Value of the Mountain Valley Pipeline Has Declined Over Time

The non-binding open season for the MVP project was announced in June 2014, inviting commitments for contracts for firm transmission capacity.[12] By September, the project had received firm capacity commitments totaling 1.5 Bcf/d—a milestone that an EQT officer stated "confirms that we have an economically viable project."[13] Indeed, natural gas production in 2014 in the Marcellus Shale had outpaced growth in the natural gas pipeline capacity in the region, leading

[11] *Id.* Note that the data presented for 2017 include January 1 through May 19 only. Basis differentials between Dominion South and Henry Hub increased slightly in June and July, which accounts for the $0.53 per MMBtu difference reported by EIA and discussed on page 6 of this report.

[12] EQT. June 2014. EQT and NextEra Energy Announce Southeast Pipeline Project. Available at: http://media.eqt.com/press-release/eqt-and-nextera-energy-announce-southeast-pipeline-project

[13] EQT. September 2014.

to an oversupply of natural gas and declining prices at regional hubs and a basis differential of more than $1.00 per MMBtu between Dominion South and Henry Hub.[14] Based on these 2014 price differentials, the Mountain Valley Pipeline appeared to be a reasonable project to undertake, as foundation shippers contracting for firm transmission capacity would have had access to lower cost natural gas from the surrounding region.

The value of these 20-year foundation transportation agreements on the MVP has diminished over time, however, with the addition of new and expanded pipeline capacity that came online at the end of 2016 and the beginning of 2017, as discussed in Section II above.[15] The diminishing value is evidenced through the dissipating basis differentials between Transco Zone 5, Dominion South, and TETCO M2 hubs versus Henry Hub. Transco Zone 5 was selected for this analysis because it is the point at which the MVP connects to the Transco pipeline, and is the area in which ConEd would buy gas in the absence of the MVP. The Dominion South and TETCO M2 hubs were selected because they are the pricing hubs at which ConEd would purchase natural gas that would then be shipped on the MVP under the 20-year contract.[16] The locations of those pricing hubs are shown in Figure 4, below.

[14] US EIA. 2014. Some Appalachian natural gas spot prices are well below the Henry Hub national benchmark. Available at: https://www.eia.gov/todayinenergy/detail.php?id=18391

[15] During this timeframe, the ownership structure of the Mountain Valley Pipeline project changed, with Vega Midstream MVP LLC, WGL Midstream, and RCG Midstream joining EQT Corporation and NextEra Energy Inc. as owners of the project. WGL Midstream purchased Vega Midstream MVP LLC's ownership interest on October 31, 2016. Business Wire, "WGL Midstream Acquires Additional 3 Percent in Mountain Valley Pipeline," (October 31, 2016), http://www.businesswire.com/news/home/20161031005163/en/WGL-Midstream-Acquires-Additional-3-Percent-Interest.

[16] In 2018, the difference is taken between the average basis differentials from 2014-2017 from TCO (Columbia Gas) and Transco Zone 4 in order to represent the change in basis differential that might be expected when the MVP begins operation.

Figure 4. Map of natural gas pricing hubs

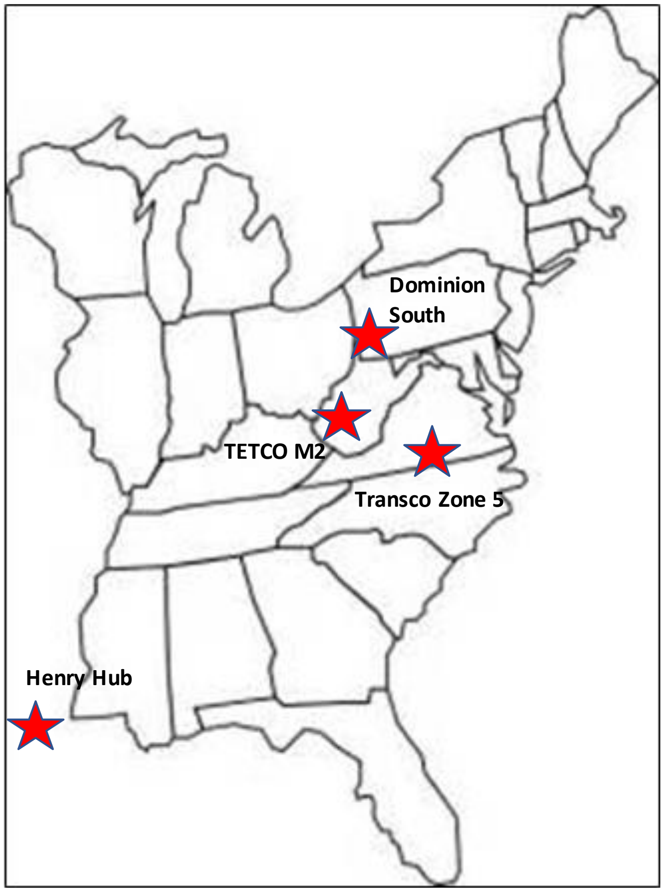
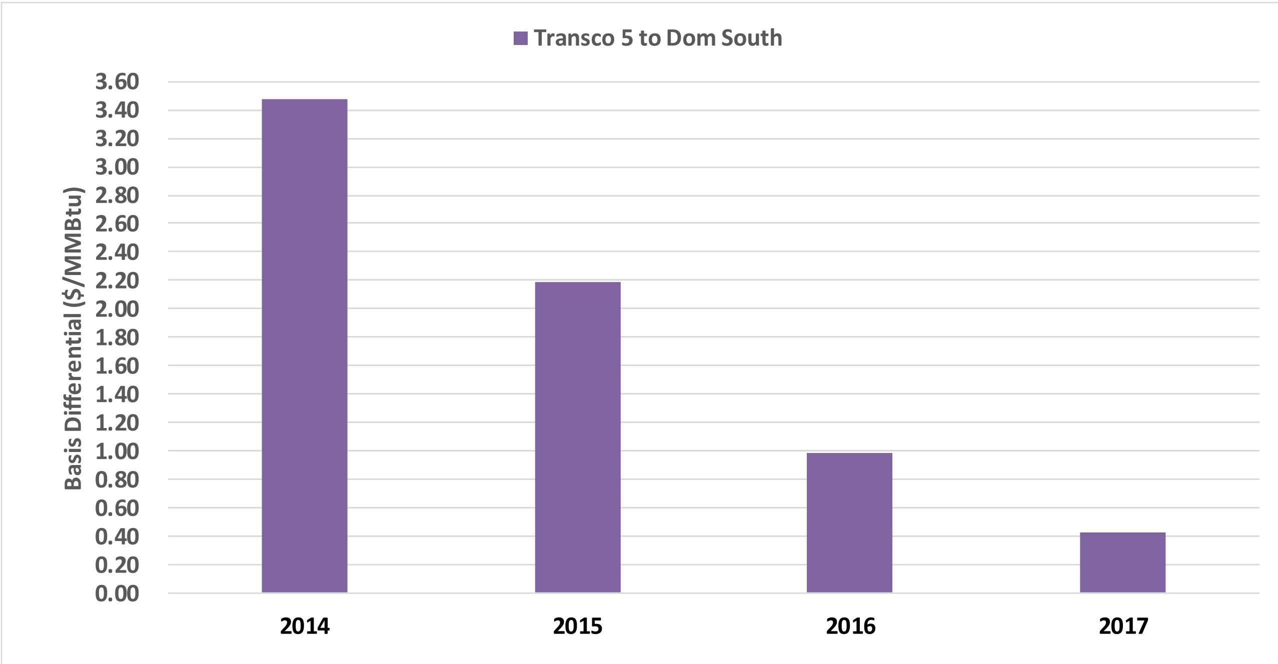


Figure 5, below, shows the shrinking basis differentials between Transco Zone 5 and Dominion South from 2014 to 2017 (partial year). This means that customers are already receiving the benefits of lower natural gas prices due to expanding pipeline capacity, as prices are equilibrating across regions and hubs.

Figure 5: Basis Differential between Transco Zone 5 and Dominion South ($/MMBtu)[17]



Additional analysis of these regional basis differentials[18] demonstrates the diminished value of the MVP pipeline over time, which is arrived at by subtracting the supply area basis differential (i.e., average of the differentials from Dominion South to Henry Hub and TETCO M2 to Henry Hub) from the Transco Zone 5 to Henry Hub basis. This represents the difference between the costs of:

(1) Natural gas that could be procured from the Marcellus and delivered via the Mountain Valley Pipeline, and

(2) Natural gas purchased at Transco Zone 5.

[17] *Id.* After July 1, 2016, Transco 5 is represented by Transco 5 North.

[18] This analysis was prepared by Greg Lander of Skipping Stone, and provided to us by EDF. Under these given assumptions, we calculated the basis differential change as follows. The basis of TETCO M2 from the Henry Hub, (a negative number), and the basis of Dominion South from the Henry Hub, (also a negative number), were averaged to calculate a composite basis supply area. Then the basis of Transco Zone 5 from the Henry Hub (a positive number in the years and in 2017, alternating between slightly negative and slightly positive numbers) was calculated to arrive at the market area basis. To calculate the value of the basis differential between the supply area and the market area, the supply area basis is subtracted from the market area basis. Subtraction of the supply area basis (a negative number) from the market area basis (recently sometimes slightly negative and sometimes slightly positive) yields the basis differential, which represents the value of holding capacity to connect those two regions. Subtracting a negative number in a supply area is the same as adding the absolute value of that number to the market area value.

This difference does not include the cost of shipping. The difference between these basis differentials is the value of the MVP; it diminishes over time as shown in Table 1. The timeline begins in 2015, the first full year in which foundation shipping agreements were available for contract on the MVP.

Table 1: Value of MVP Capacity over Time[19]

Year	Value of MVP Capacity (Dth/d)
2015	$2.17
2016	$0.99
2017	$0.42
2018 and forward	$0.08

IV. Con Ed's MVP Contract Will Result in Higher Costs to Ratepayers

The Mountain Valley Pipeline developers filed an application for a certificate of public convenience and necessity with FERC on October 23, 2015. Three months later, on January 22, 2016, ConEd announced its decision to become a shipper and Con Edison Gas Midstream an owner of the project. ConEd's stated rationale for signing up for service on the project was to gain access to lower cost natural gas supply for its customers.[20] The New York Public Service Commission evaluates the prudency of utilities' decisions at the time they enter into transactions,[21] noting that "[c]ompetitive conditions and market prices and proper provision for the future must be taken into account."[22] It is, therefore, imperative that the pricing dynamics are analyzed with a view to the time at which Con Ed made the decision to enter into this agreement (i.e., January 2016), taking into account the forecasts and projections of future trends with respect to natural gas supply, demand, and pricing that were available at that time.

[19] 2015 through 2017 values are actuals. The 2018 and forward value is calculated based upon long-term dynamics at work in the relevant supply and market areas. We assumed that the completion of projects already under construction would relieve over-supply issues in the supply area and increase supply to the market area such that those respective area prices would equilibrate to their adjacent pricing hubs. In the case of the MVP supply area, those prices are assumed to converge with the Columbia Gas Transmission supply pool (TCO Pool) while the Transco Zone 5 prices would converge with the Transco Zone 4 pricing point. The result is a lower basis differential across MVP over the long term.

[20] *See* Consolidated Edison 2016 Rate Case, Case 16-G-0061, Ivan Kimball Gas Supply Testimony at page 21.

[21] *Long Island Lighting Co. v. Pub. Serv. Comm'n*., 134 A.D.2d 135 (N.Y. App. Div 3d Dep't 1987) (explaining that the legal test for prudence is whether the utility acted reasonably, under the circumstances at the time, "considering that the company had to solve its problems prospectively, rather than in reliance on hindsight.").

[22] *In the Matter of Republic Light, Heat and Power Co., Inc. v. Pub. Serv. Comm'n of N.Y.*, 265 A.D. 74 (N.Y. App. Div 3d Dep't 1942).

With this framework in mind, Applied Economics Clinic was asked by Environmental Defense Fund to perform an assessment of whether ConEd's subscription of capacity on the Mountain Valley Pipeline would result in unjust and unreasonable costs to ratepayers. Given that the project had already been filed at FERC, ConEd could benefit from the diminishing basis differentials resulting from the project, irrespective of whether it signed a 20-year transportation contract. In short, ConEd could purchase gas out of MVP and into Transco Zone 5 and use its existing transportation rights on Transco to bring that gas to its City Gate.

Because Con Ed has already committed its ratepayers to a 20-year transportation contract, however, the costs of this transportation capacity must be considered in assessing the value to ratepayers. We estimated the ratepayer impact of the 20-year transportation agreement over time using EDF's assumption of a $29.60 per Dthd monthly cost of ConEd's MVP contract.[23] At a load factor rate of 100 percent, and with an assumed 20 percent discount for foundation shippers, the likely ConEd shipper rate was estimated by EDF to be $0.78 per Dth.[24] EDF added the value of the MVP capacity, shown above, to this shipper cost to arrive at the net daily cost to ConEd ratepayers of natural gas plus transportation. By multiplying this cost by the ConEd subscription of 250,000 dekatherms per day, we estimated costs (or savings) to ratepayers. These costs (or savings) are shown in Table 2. Red values in parentheses represent savings to consumers from the MVP, from a lower cost of gas from the Marcellus plus MVP transportation than the cost of purchasing gas at Transco Zone 5. The values in black represent a cost to consumers of Marcellus gas plus MVP transportation, above the cost of purchasing gas at Transco Zone 5.

Table 2: Costs/(Savings) to Ratepayers from the 20-year transportation agreement and cost of Marcellus gas[25]

Year	2015	2016	2017	2018+
NPV 20-year gas + contract cost	($1,244,597,148)	($186,241,814)	$318,369,888	$629,876,647
Average annual cost	($62,229,857)	($9,312,091)	$15,918,494	$31,493,832
Levelized net cost ($/MMBTU)	($1.39)	($0.21)	$0.36	$0.70

Under these assumptions, the MVP would have had a benefit to ConEd ratepayers in 2015 and 2016 due to the basis differentials that existed between natural gas pricing hubs in the Marcellus and Henry Hub, but the expected benefit was rapidly diminishing at the time ConEd entered into a contractual obligation for firm transportation service. As new and expanded pipeline capacity came online at the end of 2016 and the beginning 2017, basis differentials between the MVP supply and market regions fell, eroding the benefits of the shipping agreement on the Mountain Valley

[23] This value is derived from MVP's FERC application in Docket No. CP16-10 at Exhibit N (Revenues, Expenses, and Income).

[24] The $29.60 monthly reservation rate is rounded up from $29.5967 in MVP's FERC application at Exhibit N. Assuming an average of 30.4 days per month in a 12 month year (i.e., 365/ 12) the daily reservation rate is derived by dividing $29.60 by 30.4 or $0.9730 per Dth per day. Then discounting this by 20% yields the assumed $0.78 per Dth per day (Dthd).

[25] Average annual cost and levelized net cost are on an NPV basis.

Pipeline. It is difficult to fathom how ConEd could have failed to anticipate these diminished basis differentials, given the volume of pipeline capacity expected to come online during this period, and the number of projects still in advanced stages of development.

V. The MVP Contract Locks Con Edison Customers into Higher Rates for 20 Years

In its most recent natural gas rate case in 2016, ConEd witness Ivan Kimball stated that the Company "is looking to select pipeline projects that increase the reliability of our system, increase our flexibility, provide access to an abundant source of supply, are feasible to complete, and provide delivered gas that is economic compared to existing alternatives."[26] Signing a 20-year transportation agreement on the MVP for 250,000 dekatherms per day runs counter to this strategy of increasing flexibility at a lower delivered cost of natural gas. With the signing of this agreement, ConEd customers are locked into the 20-year transportation costs on the Mountain Valley Pipeline at a total nominal cost of $1.2 billion over twenty years.[27] The utility must also purchase natural gas from a supplier along the pipeline in order to utilize that firm transportation capacity. Natural gas from the MVP must be shipped along additional pipelines, incurring additional shipping fees, in order to bring it to customers in ConEd's service territory. If lower priced natural gas becomes available elsewhere, ConEd loses the opportunity to purchase that gas and pass those lower prices on to consumers. ConEd ratepayers are locked into higher prices for the 20-year duration of the Mountain Valley Pipeline agreement.

Given that the MVP had a sufficient number of signed shipper agreements to confirm that the project was "economically viable" in 2014, and that MVP filed a certificate application with FERC three months before ConEd decided to take service on the project, the pipeline construction would have proceeded whether or not ConEd committed its customers to a 20-year obligation to buy transportation service. Nonetheless, the utility has obligated its ratepayers to take on the costs to reserve shipping rights on that new pipeline.

The costs of the MVP contract, which total $1.2 billion (nominal) over the course of the 20-year contract, will be shouldered by New York ratepayers, whether or not the pipeline capacity is used.[28] These transportation costs are recovered from ratepayers as part of a gas cost reconciliation process before the New York State Public Service Commission. As the Commission assesses these costs, it has a responsibility to consider the affiliate relationship underpinning ConEd's interest in this pipeline and require ConEd to demonstrate that its decision to enter into this agreement is in the public interest.

[26] *See* Consolidated Edison 2016 Rate Case, Case 16-G-0061, Ivan Kimball Gas Supply Testimony at page 22. Available at: https://legacyold.coned.com/2016-rate-filing/pdf/testimony-exhibits-gas/13-gas-supply-testimony-final.pdf

[27] And a net present value cost of over $600 million, as calculated above.

[28] This cost could be reduced to $600 Million of net cost, only if the capacity is fully used and the calculated $0.08 per Dth "value" is realized thus reducing the $0.78 per Dthd cost to $0.70 per Dthd. However, this would only be the case if there are no other sources of supply into pipelines directly connected to ConEd that are more advantageous than receiving gas into Transco at the Zone 5 terminus of MVP.

Exhibit __ (GL-5):

Letter from Con Edison to EDF; Case No. 93-G-0932

conEdison
a conEdison, inc. company

Consolidated Edison Company
of New York, Inc.
4 Irving Place
New York, NY 10003
www.conEd.com

December 27, 2016

Kathleen H. Burgess
Secretary to the Commission
New York State Public Service Commission
Three Empire State Plaza
Albany, NY 12223

Re: Case No. 93-G-0932 – EDF Request for Heightened Scrutiny of Precedent Agreements Supported by Affiliates

Dear Secretary Burgess:

On November 29, 2016, the Environmental Defense Fund ("EDF") filed a letter in the above-referenced proceeding regarding the Commission's review of natural gas supply and transportation agreements. EDF says that current practices designed to meet statutory requirements for gas utilities to file such agreements with the Commission are no longer adequate. According to EDF "[a] new predominant model has emerged regarding the funding of long-term pipeline capacity," as evidenced by several recent certificate applications before the Federal Energy Regulatory Commission ("FERC") where pipeline developers and regulated utilities contracting for new pipeline capacity are increasingly part of the same corporate group. Because of this, and EDF's related concern that these circumstances could shift risk to, and impose long-term environmental and economic costs on, captive ratepayers, EDF states "the Commission should require any utility seeking to enter into any affiliate transaction to provide advance notice to the Commission and obtain Commission approval to initiate negotiations as among affiliates," and that these affiliate arrangements be subject to "enhanced scrutiny." For the reasons explained in this letter, the Commission does not need to take action on EDF's request.

First, EDF's request for "enhanced scrutiny" springs from its belief that the Commission's review process is limited to the Public Service Law ("PSL") §110 requirement for gas utilities to file with the Commission their gas supply agreements with affiliates and non-affiliates. It does not account for the current Commission processes that precede gas utilities reaching the contract filing stage. For example, each year, the Commission establishes a formal proceeding the subject of which is examination of gas utility supply plans by the Staff of the Department of Public Service ("DPS Staff"). For 2016, the proceeding is Case 16-M-0263. On the Commission webpage for that proceeding is myriad redacted material filed by all of the State's gas utilities, including Consolidated Edison Company of New York, Inc. ("CECONY" or the "Company"), in response to Staff's inquiries regarding various gas supply matters, including expected portfolio changes over the next five years; supply diversity and price risk management; evolving market conditions; and impacts on customer bills. These interactions between utilities in the State and DPS Staff pursuant to this annual Commission process are supplemented by additional and ongoing informal interactions, as necessary and appropriate, when circumstances change and/or new information becomes available.

Second, EDF does not account for long-standing Commission policy that gas supply arrangements and other gas strategy information contain commercially-sensitive information and protected confidential information that, if disclosed, could adversely affect utility customers.[1] Accordingly, information filed by gas utilities in the annual gas supply review proceedings is filed pursuant to the Commission's trade secret provisions, as are utilities' executed gas supply arrangements.[2]

Third, EDF advocates for a change in Commission policy for new infrastructure projects involving affiliates, citing as an example a recently filed precedent agreement between CECONY and Mountain Valley Pipeline, presumably because this indicates a change in the status quo. That is not the case. Gas infrastructure projects designed to meet the needs of New York utility customers, in which a utility affiliate has an interest, are not new and have resulted in material benefits to New York consumers. Moreover, such transactions are adequately and appropriately addressed by existing Commission processes.[3]

Fourth, EDF's proposal to require gas utilities to obtain Commission approval prior to initiating negotiations with an affiliate forecloses options that may be beneficial to customers and conflicts with the Public Service Law. New gas infrastructure is needed to meet the needs of gas customers in CECONY's service territory, including new gas customers and/or to enhance utility access to new lower cost gas supplies. Requiring Commission approval before a gas utility may initiate steps to obtain rights to pipeline or storage capacity because its affiliate has an ownership interest in such project could preclude gas supply opportunities that may be the preferred alternative to meet utility customer needs. And while CECONY will advocate strongly for the success of a pipeline project needed to serve its customers irrespective of affiliate involvement, having an affiliate as an investor in the project will add a strong advocate that is informed of and sensitive to issues that may be of concern to the New York Commission and other local authorities, as well as having a vested interest in its affiliated utility achieving gas supply objectives needed to meet the needs of New York consumers. Further, subjecting an affiliate's ability to participate in such pipeline projects to advance Commission approval would constitute undue discrimination under the provisions of the Public Service Law and unfairly and adversely impact gas utility affiliates' pipeline project opportunities. In short, a requirement that the gas utility obtain approval prior to initiating negotiations with a developer in which an affiliated entity has an interest conflicts with the letter and spirit of PSL §110 and may eliminate the ability of the utility to enter into an agreement that would provide customer benefits.

---

[1] *See*, for example, Case 08-G-0609, *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Niagara Mohawk Power Corporation for Gas Service*, Ruling Granting Protection from Disclosure for Gas Supply Contract Information and Large Gas Customers' Usage Information (issued June 20, 2008).

[2] Neither of the cases cited by EDF regarding Commission implementation of PSL §110 (*see* EDF Letter, p.2, footnotes 4 and 5), nor the Bay State decision (footnote 6), support public disclosure of the commercially sensitive information at issue.

[3] CECONY takes exception to EDF's suggestion that the Company has not been transparent regarding its contracting for capacity on a new pipeline in which its affiliate is a minority owner. While EDF is correct that the Company did not state an affiliate relationship when the Mountain Valley Pipeline precedent agreement was filed with the Commission (nor is there such a requirement), the Company has affirmatively disclosed this relationship in other publicly available documents, including, for example, in its Gas Long Range Plan (at p.51), which is posted on the Company's website (http://www.coned.com/publicissues/PDF/Gas-Long-Range-Plan.pdf) and was made available to all parties in the Company's current gas rate proceeding, including EDF.

Finally, EDF suggests that requiring a utility to obtain Commission approval to initiate negotiations as among affiliates would be similar to the requirements applied by numerous state public utility commissions. In support of this generalization, EDF provides one example, citing an order issued by the State of North Carolina Utilities Commission ("North Carolina Commission"). However, nothing in that order indicates that either public notice or prior approval of the North Carolina Commission was required for the initiation of negotiations for the affiliate transactions at issue.[4] And, as discussed above, EDF's proposed "pre-approval" requirement for initiating negotiations with an affiliate would not only violate the letter and spirit of PSL §110, it is unnecessary in light of the formal and informal review processes already undertaken by the Commission and DPS Staff.[5]

For all of the foregoing reasons, the Commission should maintain its current processes, which enable the Commission, DPS Staff and gas utilities to meet their statutory obligations as respects gas supply arrangements in a wholly effective manner, and should resist adding impediments to longstanding regulatory and business processes that may likely have adverse consequences for New York gas customers.

Respectfully submitted,

Consolidated Edison Company
of New York, Inc.

Ivan Kimball
Vice President, Energy Management
(212) 460-6060; kimballi@coned.com

Marc Richter

Marc Richter
Vice President, Regulatory Services
(212) 460-4615; richterm@coned.com

Cc: N. Jonathan Peress, EDF
Natalie Karas, EDF
Parties in Case 93-G-0932

[4] The North Carolina decision also notes that "Piedmont [the South Carolina utility] submitted the agreements under seal on the grounds that they are confidential and proprietary and have been designated as such pursuant to G.S. 132-1.2" (Order, p. 1), thereby further validating the New York Commission's long-standing practices regarding review of gas supply initiatives between utilities and DPS Staff.

[5] EDF seeks to bolster its position by citing comments submitted in 1999 by CECONY to FERC in support of constructing facilities only where market demand warrants and to reduce costs borne by consumers. The Company stands by its comments in that proceeding, which were filed in response to a FERC Notice of Proposed Rulemaking and Notice of Inquiry and made in the context of very specific facts and circumstances. In contrast, EDF raises no specific facts or circumstances that warrant a change to current Commission practices, which are designed for gas utilities to pursue gas supply arrangements at lowest reasonable costs consistent with reliability and operational and other considerations, whether with affiliated or unaffiliated companies.

Exhibit __ (GL-6):

Winter Supply Review Data Request;

Case No. 18-M-0272

Case 18-M-0272
Submission Date July 16, 2018
Version #:1

Case 18-M-0272 - Winter Supply Review Data Request

Issues 1 and 2
Please provide the following information related to your company' s portfolio and purchasing strategy for the upcoming 2018-19 send out year and anticipated portfolio changes over the next five years, and:

1. Table 1: System design day capacity capability by service area (or gate when indicated) and peak design day demand by service area (or gate when indicated). Please include all capacity volumes, including all recallable capacity assets that are available or needed for peak design day and specify the volumes supporting sales, transportation customers and retail access capacity release. Include last year's 2017-18 Table 1 (final update) data for purposes of comparison. The total capacity capability must meet or exceed the design peak day demand value provided. Identify any projected capacity assets that are not yet finalized but will be prior to the upcoming winter heating season, including both a description and projected completion date.

Response 1 (Business Confidential)

Table 1 shows the Companies' combined system peak day capacity submitted last year for the 2017-18 winter period and currently projected for the 2018-19 winter period. Volumes are by service area are intended to support all firm customers.

2. Table 2: Estimated annual, winter season, and daily requirements by service area (or gate when indicated) for last year and the next five years, using design weather. Include a description of the design weather criteria and explain any changes from the previous year. Specifically, since many areas of the state experienced **an extended period of colder than** normal weather **last winter,** how does this experience impact your daily or winter season design parameters and are there any changes required? Also, how is this affecting your storage injection season and how will it be addressed? The 2017-18 actual data experienced last year is to be included for purposes of comparison. **Also include any and all service areas (or gate stations when indicated) where moratoriums have been put into place or have the possibility of being instituted in the next five years. Identify where any curtailments to firm customers may occur.**

Case 18-M-0272
Submission Date July 16, 2018
Version #:1

Response 2 (Business Confidential)

[redacted]

In the Smart Solutions for Gas Customers Petition filed on September 29, 2017, CECONY stated "the Company forecasts that in the near term it may be unable to meet demand from new customers on extremely cold days, resulting in the need to institute moratoriums on attaching new firm gas customers in areas where pipeline capacity is severely constrained." In a supplemental May 4, 2018 filing in that proceeding, CECONY stated that it "has previously mentioned that temporary moratoriums are a possibility and is increasingly concerned that they will be necessary." As stated in that proceeding, CECONY believes that moratoriums may be necessary in the near term but it currently cannot state when and where it would institute moratoriums. CECONY notes, however, that it recently ended its Area Growth Program for Westchester, due to both the lack of interest and pipeline constraints.

CECONY cannot predict at this time when and where moratoriums may be necessary because it is currently: (1) evaluating responses to its market solicitation for Non-Pipeline Solutions; and (2) updating planning with National Grid for the jointly owned New York Facilities system. After CECONY has complete these two items it will have the information it needs to determine when and where temporary moratoriums may be needed.

O&R does not anticipate the need for any moratoriums in its service territory within the next 5 years.

In the absence of extreme weather, neither Company currently believes that there will be any curtailments to firm customers over the next five years.

3. Table 3: Same information as requested in (2), but using normal weather. Include a description of the normal weather criteria and the calculation methodology. The 2017-18 data submitted last year is to be included for purposes of comparison. Please Note: if Table 3 is based on a sales forecast using anything less than 30 years of weather data, no part of Table 3 may be used to develop any part of Table 2.

Response 3 (Business Confidential)
Table 3 shows, by service area, the Companies' estimated annual, winter season, and peak day requirements for last year and the next five years, using normal weather.

4. Identify your source for heating degree day (HDD) data, including the specific weather data points used for forecast purposes. Describe your source and/or your calculation of design day and design winter data (i.e. calculated from normal usage or an actual historic period). Identify the time periods used to develop usage per HOD for both design and normal usage, and explain the frequency of updates. If 30 years of data is not being used for design, please explain why. Please explain how usage per HDD for the peak period is calculated and verified.

Response 4

The CECONY and O&R Normal Demand Forecast for volume equations are developed based on data from the latest 12 month period. 30 years of HDD data is then used to calculate the seasonal and annual forecasted normal volumes. Central Park weather data (including HDD) is obtained from a vendor and ORU weather data (including HDD) is obtained from the Company's Spring Valley weather station.

The CECONY Peak Demand Forecast equations are developed based on pooled weather adjusted data from past winters.. Our weather adjustment is based on a design criteria of zero degree Temperature Variable (TV). The gas day average (GDA) temperature is a 24 hour arithmetic average starting at 10 AM using the Central Park Weather Station dry bulb temperature. The TV is calculated by taking 70% of the current day's GDA and 30% of the previous day's GDA. Regression analysis is performed to determine the weather adjusted system firm peak demand. Typically, a pooled, linear regression is developed using up to five years of peak-day demand, TV, and wind speed data for the winter season (typically November 1 to March 31).

The O&R Peak Demand Forecast equations are developed based on pooled weather adjusted data from past winters. Our weather adjustment is based on a design criteria of zero degree TV. The GDA temperature is a 24 hour arithmetic average starting at 10 AM using the Spring Valley Weather Station dry bulb temperature. The TV is calculated by taking 80% of the current day's GDA and 20% of the previous day's GDA. Regression analysis is performed to determine the weather adjusted system firm peak demand. Typically, a pooled, linear regression is developed using up to three years of peak-day demand, TV, and wind speed data for the winter season (typically November 1 to March 31).

5. Describe the load forecasting tools used to develop the above forecasts. Indicate how all natural gas efficiency programs, Demand Response Programs, Microgrids, and Non- Pipe Alternatives (NPA) conducted by your company, contractors or the New York State Energy Research and Development Authority (NYSERDA) have been incorporated into these forecasts and your capacity planning. Provide a summary of the projected energy savings and the actual savings realized to date. How are these savings translated into the normal usage projection in Table 3?

Response 5

The forecasting tools Gas Forecasting utilizes for the CECONY and O&R Peak Demand Forecasts are: A customized regression model for the weather adjusted peak (Excel/SAS), and a customized forecasting model for adding load growth and subtracting energy efficiency to the weather adjusted peak (Excel). Weather vendor services, EViews, Moodys Economic Model Results, Company Project Management System for CECONY new business, and the New Construction system for O&R

new business are tools that provide data for these models, and taking inputs from other areas of the Companies to determine the level of gas conversions, energy efficiency, distributed generation, and any other factor that may have an impact on future peak demand.

The forecasting tools Revenue and Volume Forecasting utilizes for the CECONY and O&R gas energy forecasts are customized models for customer growth, establishing a base period from actual energy, and taking inputs from other areas of the Company to determine the level of gas conversions, energy efficiency, distributed generation, and any other factor that may have an impact on future energy use.

The CECONY Gas Peak Demand Forecast is developed based upon a weather adjusted peak which is modified for load growth and energy efficiency programs. The load growth accounts for: conversions of #2, #4, and #6 oil to natural gas, large new construction, steam to gas conversions, DG/CHP, changes in projections for multifamily housing completions in N.Y. Metropolitan Area, natural conservation and energy efficiency programs, customer movement between firm and interruptible service.

For 2017, the CECONY Energy Efficiency Transition Implementation Plan (ETIP) resulted in approximately 326,154 Dt of natural gas savings. The effect on the peak gas day was an estimated reduction of about 2,100 Dt. For the next 5 years, the Company projects the annual savings from Energy Efficiency and Demand Response to reach approximately 3,200,000 Dt, or roughly 30,000 Dt for the peak-day for CECONY. These amounts are embedded in the peak and sales information included in Table 3. Additionally CECONY's Forecast includes a projection of organic EE and natural conservation. This category bounds any other NYSERDA, NYC, and other federal EE programs.

The O&R Gas Peak Demand Forecast is developed based upon a weather adjusted peak which is modified for load growth and energy efficiency programs. The load growth accounts for: conversions of #2 oil to gas, commercial and residential growth, new businesses, DG/CHP, and natural conservation and energy efficiency programs.

For 2017, the O&R ETIP resulted in approximately 38,249 Dt of natural gas savings. The effect on the peak gas day was an estimated reduction of about 25 Dt. For the next 5 years, the Company projects the maximum annual savings from ETIP to reach approximately 43,106 Dt, or about 29 Dt for the peak gas day for O&R. These amounts are embedded in the peak and sales information included in Table 3. Additionally O&R's Forecast includes a projection of organic EE and natural conservation. This category bounds any other NYSERDA and other federal EE programs.

For CECONY and O&R demand equations (base and heat) are calculated by performing regression analyses of anticipated customer load and weather conditions. The forecasted load requirements under normal and design weather conditions are developed with the application of calculated demand equations to both normal and design weather patterns.

The impact of Con Edison's December 15, 2017 Non-Pipeline Solutions RFP was based on a preliminary estimate of the peak day impacts of the 8 credible demand-side proposals received. The proposals would implement a number of electrification, energy efficiency and demand response measures across the company's service territory. Because evaluation of the proposals and contract

Case 18-M-0272
Submission Date July 16, 2018
Version #:1

negotiations are not complete, the respondents' estimate of 39,000 Dt/day of design day load reductions were adjusted downwards by several factors, including factors intended to recognize potentially overly optimistic estimates of performance and factors intended to recognize the risk associated with planned program or project and the qualification level of the respondent, as determined by Con Edison's internal selection committee.

Determining the impact of the pilot Gas Demand Response program was based upon a preliminary estimate of the potential reduction across Con Edison's gas territory. The total energy savings was based on several data points including neighboring utilities, experience from electric demand response, bill analysis and external party analysis. The reduction level ramp rate corresponds to the AMI rollout since the Company believes the installation of AMI will encourage customers to become more sensitive to their gas consumption.

The "Con Edison DER Potential Study Supplemental Report: Natural Gas Add-On Analysis" was used in developing the forecast for the incremental energy and peak day savings impact resulting from Con Edison's Enhanced Gas Energy Efficiency Programs.

6. What is your current forecast/planning horizon for supply and capacity purposes and explain why it is used? If you aren' t using a minimum of five years for system planning, please explain.

Response 6

The Companies' develop a Long-term Gas Supply Plan that evaluates supply and capacity requirements over a ten-year planning horizon. In addition, the Plan is integrated into and extended as part of the Companies' Gas, Steam and Electric long-term plans over a 20-year planning horizon.

7. A winter season load duration curve for 2018-19 send out year that shows how supplies can meet a severe winter season and peak design day. This should be provided for each service area (or gate when indicated). Include all data in an unlocked digital Microsoft Excel file.

Response 7

Exhibits 1 shows, by service area, the Companies' current system forecasts winter season firm customer load duration curve under design weather condition and available assets to meet the requirements for winter 2016-17.

8. Provide this years and last years planned storage curves versus actual storage curves for injections and withdrawals.

Response 8 (Business Confidential)

Case 18-M-0272
Submission Date July 16, 2018
Version #:1

[redacted]

[redacted]

9. Describe the storage injection plan for this injection season and highlight any modifications from the prior year plan.

Case 18-M-0272 Submission
Date July 16, 2018 Version #:1

Response 9 (Business Confidential)

[redacted]

[redacted]

[redacted]

10. Provide the method(s) used by the Company to determine or ensure the least cost dispatch when the heating season is warmer than normal.

Response 10

The Companies considers several factors for providing least cost dispatch. During periods when the heating season is warmer than normal, the Companies consider supplies that have already been procured, the cost of storage inventory at each facility (taking into account requirements for must turn), the injection capabilities of the storage fields during the heating season, the decrease in requirements at the various gates and the pipelines that deliver there, and the price of spot gas at the various citygate locations.

11. Provide the Company must turn requirements for each storage facility(s).

Response 11 (Business Confidential)

[redacted]

[redacted]

Case 18-M-0272
Submission Date July 16, 2018
Version #:1

[redacted]

Issue 3
Please provide the following information related to your company's operations and optimization procedures:

12. A send out schedule (or curve) for forecasting requirements under the varying conditions that are considered in developing the estimates (M-, temperature, wind, weekend/weekday, etc.).

Response 12

Exhibit 2 shows the curve for estimating send out requirements as a function of heating degree-days for the combined CECONY and O&R service areas. Also included on the same page are adjustment tables, based on empirical data, for the CECONY and O&R service areas.

13. Gas supply portfolio information (highlight changes as indicated on the charts, including all capacity or supply contracts remaining to be finalized prior to the winter heating season):

a. Table 4: Transportation capacity data including contract volumes and expiration dates. Please be prepared to discuss how the capacity is actually used during our meeting.
b. Table 5: Storage capacity data, including contract volumes and expiration dates.

Case 18-M-0272
Submission Date July 16, 2018
Version #:1

At our meeting, please be prepared to provide the current average price of gas in storage and your forecast for November.

c. Table 6: Gas supply contract data including contract volumes, terms and expiration dates.

Response 13a

Table 4 includes all of the pipeline firm transportation capacity contract paths for the combined Companies. As capacity contracts expire, the Companies plan to renew contracts that are necessary to meet core customer requirements, to meet forecasted design conditions, and to maintain system reliability.

Response 13b

Table 5 includes all of the firm storage contracts with the requested information for both the market area and production area storages.

Response 13c

Table 6 is still being developed and will be included in the August update to this filing. Table 6 will include the firm gas supply contracts for long-term and short-term supplies. The Companies have entered into a combination of annual and winter supply contracts with some of the major producers and marketers in the production area and will utilize long-haul pipeline transportation contracts for deliveries to the Companies' citygates. In addition, the Companies have also entered into citygate delivered winter peaking supply contracts with suppliers that hold primary firm pipeline capacity to the Companies' citygates.

14. Please provide a flow diagram of the gas system showing how the assets included in Tables 4, 5 and 6 are utilized to provide service to your customers.

Response 14

A flow chart depicting Gas Supply's assets flow is included as Exhibit 3.

15. Are you aware of any pipeline or other capacity asset projects that will or could impact your ability to deliver or supply gas (i.e. Constitution Pipeline, NFGS Northern Access, Williams Northeast Supply Enhancement Project, etc.)?

Response 15

[redacted]

[redacted]

Case 18-M-0272
Submission Date July 16, 2018
Version #:1

[redacted]

[redacted]

[redacted]

16. Describe, if applicable, current practices and any anticipated changes related to on- system peaking facilities and other peak shaving techniques. If you operate LNG peaking facilities, please describe current plans for any activities at the facilities that would interrupt their availability and steps being taken to mitigate those interruptions. Please also list any anticipated permitting issues or resistance from local or other government entities.

Response 16

There has been no change to the storage and vaporization capability of the LNG plant since the 2016-2017 winter preparedness meeting.

17. A list of the dates, times and durations of all OFOs and interruptions or curtailments on your system during the 2017-18 heating season. Please differentiate the interruptions and curtailments between electric generator and other interruptible customer class curtailments.

Response 17

OFOs issued to Power Generation during the 2017-18 Winter Season

Case 18-M-0272
Submission Date July 16, 2018
Version #:1

2017-2018 Power Generation OFO Log						
Start Date	**Start Time**	**End Date**	**End Time**	**Steam Hourly Limitations**	**Power Gen Hourly Limitations**	**Daily Balancing Limitations**
11/4/2017	10:00 AM	11/6/2017	10:00 AM	None	None	Low burn 2% or less
11/10/2017	10:00 AM	11/13/2017	10:00 AM	None	None	High Burn 2% or less
12/14/2017	10:00 AM	12/16/2017	10:00 AM	None	None	High Burn 2% or less
12/26/2017	10:00 AM	1/9/2018	10:00 AM	120%	120%	High Burn 2% or less
1/14/2018	10:00 AM	1/19/2018	10:00 AM	120%	120%	High Burn 2% or less
1/27/2018	10:00 AM	1/29/2018	10:00 AM	None	None	Low burn 2% or less
2/2/2018	10:00 AM	2/5/2018	10:00 AM	None	None	High Burn 2% or less
2/8/2018	10:00 AM	2/9/2018	10:00 AM	None	None	High Burn 2% or less

OFOs issued to Gas Marketers during the 2017-18 Winter Season

2017-2018 Marketer OFO Log				
Start Date	**Start Time**	**End Date**	**End Time**	**Reason**
11/4/2017	10:00 AM	11/6/2017	10:00 AM	Under Burns
11/10/2017	10:00 AM	11/13/2017	10:00 AM	Over Burns
12/14/2017	10:00 AM	12/16/2017	10:00 AM	Over Burns
12/26/2017	10:00 AM	1/9/2018	12:00 PM	Over Burns
1/14/2018	10:00 AM	1/19/2018	10:00 AM	Over Burns
1/27/2018	10:00 AM	1/29/2018	10:00 AM	Over Burns
2/2/2018	10:00 AM	2/5/2018	10:00 AM	Over Burns
2/8/2018	10:00 AM	2/9/2018	10:00 AM	Over Burns

Interruption dates for Electric Generation Customers during the 2017-18 Winter Season

2017-2018 Power Generation Interruption Log					
Start Date	**Start Time**	**End Date**	**End Time**	**Duration (Hrs)**	**Customer Type**
1/7/2018	04:00AM	1/7/2018	10:00AM	6	Power Gens

Interruption dates for Interruptible Customers during the 2017-18 Winter Season

Case 18-M-0272
Submission Date July 16, 2018
Version #:1

2017-2018 Notification Interruption Log					
Start Date	**Start Time**	**End Date**	**End Time**	**Duration (Hrs)**	**Customer Type**
11/7/2017	10:00 AM	11/7/2017	02:00PM	4	Pre-Season Test
12/27/2017	10:00 AM	1/8/2018	10:00 AM	288	Sales & Transportation

2017-2018 Temperature Controlled Interruption Log					
Start Date	**Start Time**	**End Date**	**End Time**	**Duration (Hrs)**	**Customer Type**
12/27/2017	6:00 AM	12/27/2017	2:00 PM	8	Temp. Control
12/27/2017	8:00 PM	1/2/2018	12:00 PM	136	Temp. Control
1/3/2018	12:00 AM	1/3/2018	10:00 AM	10	Temp. Control
1/5/2018	12:00 AM	1/8/2018	9:00 AM	81	Temp. Control
1/14/2018	12:00 AM	1/15/2018	10:00 AM	34	Temp. Control
1/31/2018	6:00 AM	1/31/2018	10:00 AM	4	Temp. Control
2/2/2018	9:00 PM	2/3/2018	10:00 AM	13	Temp. Control

18. An explanation of how the company determines capacity and peaking supplies required for each of its interruptible service classes, if utilized.

Response 18

The Companies do not purchase capacity or peaking supply for their interruptible customers.

19. A description of the long and short-term forecasting process used for gas dispatch purposes. Include all weather services and a description of any in-house software utilized. Please explain how accurate your short-term forecasts were during the 2017-18 heating season by using a back cast after the actual weather is known.

Response 19

The Companies use a single forecasting model (1 to 5 days). It is done by Gas Control and utilizes an in-house developed similar day look-up algorithm (look up includes weather, day of week, and month) as well as a neural network application developed and provided by Marquette University; an in-house network application has been developed by Itron to back up the neural network application. The weather forecast service provider is Telvent / Schneider Electric. The average daily forecasting error was 2.7% for this period.

20. If your company has had a management audit within the last three years, please list any recommendations from that audit that relate to gas supply procurement, load forecasting , gas price risk management, or system planning. Explain whether or not these recommendations have been implemented, and the status of any changes.

Response 20

CECONY completed a management audit in 2016. There was one recommendation related to gas system planning:

Reevaluate the projected costs and timeline of the Accelerated Main Replacement program for consistency with project objectives.

CECONY has revisited the Accelerated Main Replacement program during the current rate case filing and has addressed resource and knowledge gaps as a result of discussion prior to and during the management audit process. CECONY believes the plan outlined in the current rate case filing is feasible and needs no further alteration. PSC Staff closed this recommendation as of company's Audit Implementation Plan update, dated June 13, 2017.

21. A detailed description of any existing asset management or asset optimization agreements, as well as any such agreements being considered or planned. All agreements that include firm capacity and/or supply that is recallable during the winter heating season should be included in table 1.

Response 21 (Business Confidential)

This year, the Companies have entered into AMAs with counterparties to manage a combination of supply/capacity to the citygate, summer storage fill requirements, and winter storage delivery to the citygate. The Companies have entered into the following AMAs:

[redacted]

Case 18-M-0272
Submission Date July 16, 2018
Version #:1

[redacted]

Future asset management arrangements will be considered as opportunities arise.

22. A description of your company's plans and strategy with respect to off-system sales, capacity release and streaming arrangements for the 2018-19 winter season as well as any such transactions that extend beyond the 2018-19 winter.

Response 22

During the 2018-19 winter season, the Companies plan to optimize their portfolio through capacity release, off-system bundled sales, and asset management arrangements (AMA) with third parties. Capacity is released on a seasonal, monthly and daily basis.

The Companies may make bundled sales to: (a) mitigate pipeline cashouts or penalties that could result during periods of unusually low demand, (b) manage unplanned outages at pipeline delivery points, (c) provide the system and customers operational flexibility, and (d) capture capacity value through commodity purchases at a receipt point and commodity sales at a delivery point

The Companies release transportation capacity to marketers that participate in their Retail Access Programs. For the 2018-2019 Capacity Release Program year, capacity will be released on Algonquin, Columbia Gas Transmission, Iroquois, Millennium, National Fuel, Tennessee, Texas Eastern, and Transcontinental Pipelines as further discussed in response to 23d below.

23. Status of mandatory capacity release and grandfathered capacity programs.

a. Status of marketer compliance with the Commission's primary point capacity requirement for grandfathered capacity. Include how much grandfathered capacity remains on your system.

b. Please describe the methodology utilized to determine the mandatory capacity release to the marketers. Indicate how this compares with the methodology utilized to determine capacity required for firm sales customers.

c. Please describe how your company keeps marketers informed of changes in procedures. Include the frequency and past/proposed dates of marketer meetings relating to the 2018-19 heating season.
d. List the pipelines and allocation percentages being utilized for the mandatory assignment of capacity.
e. Please provide a comparison between your company's weighted average cost of capacity and the charges paid by marketers and direct customers for released capacity. What process, if any, is utilized to true-up any differences?
f. Please describe how your company determines the daily delivery quantities (DDQ) provided to marketers each month for their daily delivery requirements. Provide a sample calculation.
g. Please indicate if any marketers serving core customers on your system failed to perform as anticipated during the previous winter, and if so, what steps you took to ensure reliability of service.

Response 23

a. Status of marketer compliance with the Commission's primary point capacity requirement for grandfathered capacity. Include how much grandfathered capacity remains on your system.

Response 23a

The Companies have no grandfathered capacity. All Marketers in the CECONY/O&R service areas are using capacity released by the Companies to serve firm customer loads.

b. Please describe the methodology utilized to determine the mandatory capacity release to the marketers. Indicate how this compares with the methodology utilized to determine capacity required for firm sales customers.

Response 23b

For Con Edison, the methodology utilized to determine the mandatory capacity release is determined by the marketer's design day: 1) aggregated non-heat sensitive load and 2) a portion of the heat sensitive load. Each Marketer's capacity from the portion of the heat sensitive load is determined through the proration of the remaining Marketers' share of the total capacity after all marketer non-heat sensitive loads is met.

For O&R, the method used to determine a marketers' capacity release volume is established by dividing a customer's weather normalized usage volume for each of the most recent twelve billing months by the total number of days in each billing month and restating the billing month usage on a calendar month basis. The daily usage volumes will be aggregated by month for each of the twelve months for all customers within a Seller's Aggregation Group. The result obtained shall be the monthly Aggregate Daily Contract Quantity ("ADCQ"). The monthly ADCQ shall be multiplied by the Company's factor of adjustment. The highest ADCQ determined in the twelve month period is the ("Max ADCQ"). The Max ADCQ shall be the amount of daily pipeline capacity to be obtained by the Seller.

The Companies have term contracted capacity on multiple pipelines with primary deliveries to each Citygate point on the Companies' system. The firm capacity requirement is determined based on forecasted demand under a winter design profile.

Please describe how your company keeps marketers informed of changes in procedures. Include the frequency and past/proposed dates of marketer meetings relating to the 2017-18 heating season.

Response 23c

Procedural changes are communicated to Marketers via written correspondence transmitted through various means of communication (i.e., U.S. Mail, e-mail, facsimile). Depending upon the complexity of the change(s), CECONY/O&R may schedule conference calls or meetings with their Marketers through a collaborative process. These communications are in addition to the annual Marketer meeting to review changes to their transportation programs for the upcoming winter season. CECONY has hosted many meetings over the past year via teleconference and in-person with the Marketers to continue discussions about the DDS program and other items of concern to the Marketers. A meeting with all Marketers (via teleconference) will be held in September relating to the 2018-19 heating season.

List the pipelines and allocation percentages being utilized for the mandatory assignment of capacity.

Response 23d

The table below shows the pipelines and allocation percentages that will be utilized for the mandatory assignment of capacity for the Winter period November 1, 2018 through October 31, 2019. Under the CECONY program, this is Tier 1 – Capacity Assignment under the DDS program. All Marketers get a slice of the system.

[redacted]

[redacted]

Please provide a comparison between your company ' s weighted average cost of capacity and the charges paid by marketers and direct customers for released capacity. What process, if any, is utilized to true-up any differences?

Response 23e

The Companies' gas tariffs specifically provide that all firm transportation customers, including direct customers, are subject to a Capacity Release Service Adjustment ("CRSA") to their SC No. 9 and SC No. 6 transportation rate to the extent that the Companies actual weighted average cost of upstream pipeline capacity ("WACOC"), for each twelve-month period commencing November 1, varies from the projected WACOC charged to Capacity Release Sellers over the same twelve-month period.

For O&R, the CRSA will be credited or surcharged through the Monthly Gas Adjustment applicable to Firm Transportation Customers over the next succeeding twelve-month period commencing November 1 and will be based on the variation between the actual WACOC and the projected WACOC for the preceding twelve-month period and the projected Ccf deliveries to Firm Transportation Customers over the next succeeding twelve-month period. The Companies' WACOC is updated periodically to reflect the Companies' current cost of firm pipeline capacity. The WACOC for the Companies effective November 1, 2017 was $0.5321

The table below shows the difference between the Companies' WACOC in effect November 1, 2016 through October 31 2017 and the CRS filed each month during this time period.

Case 18-M-0272
Submission Date July 16, 2018
Version #:1

Capacity Month	**Monthly Filed Rate**	**Monthly Release Rate**	**Difference**
Nov-16	$0.5974	$0.5974	$0.0000
Dec-16	$0.5975	$0.5974	$0.0001
Jan-17	$0.6081	$0.5974	$0.0107
Feb-17	$0.6149	$0.5974	$0.0175
Mar-17	$0.6159	$0.5974	$0.0185
Apr-17	$0.6141	$0.5974	$0.0167
May-17	$0.6139	$0.5974	$0.0165
Jun-17	$0.6138	$0.5974	$0.0164
Jul-17	$0.6136	$0.5974	$0.0162
Aug-17	$0.6141	$0.5974	$0.0167
Sep-17	$0.6150	$0.5974	$0.0176
Oct-17	$0.6152	$0.5974	$0.0178

Please describe how your company determines the daily delivery quantities (DDQ) provided to marketers each month for their daily delivery requirements. Provide a sample calculation.

Response 23f

For CECONY, the Company establishes for each day a quantity that the Marketer is obligated to deliver to the Receipt point on a forecasted temperature and an aggregated customer temperature equation. The equation is a heat slope formula determined through customer historical usage, with June, July and August as the months of non-heat sensitive load. Each Marketer will receive a slice of the Company's assets to meet its design day peak. The assets will be provided in three (3) tiers: Tier 1 – Mandatory Capacity Release; Tier 2 – Managed Supply Service (Storage) and, Tier 3 – Peaking Service.

Sample Calculation

February 2013 Aggregated customer temperature equation: DDQ = Slope X HDD + Non-sensitive heat load

Date	*Forecasted Temperature*	*Heating Degree Days (HDD)*	*DDQ (dth)*
Feb 1	32F	30	**700**
Feb 2	35F	27	**640**

*Assume slope of 20 and non-sensitive head load of 100

Case 18-M-0272
Submission Date July 16, 2018
Version #:1

O&R provides to marketers the Aggregate Daily Contract Quantity (“ADCQ”) based upon their customers’ average daily usage for the same month last year, weather normalized.

Sample Calculation
Feb 2013 - 20.1 dths (Actual Usage)
Feb 2013 – 1% Weather Normalization Adjustment (Actual vs Normal Degree Days)
Feb 2014 – 19.9 dths (DCQ)

Please indicate if any marketers serving core customers on your system failed to perform as anticipated during the previous winter, and if so, what steps you took to ensure reliability of service.

Response 23g

All Marketers in the CECONY and O&R service area performed according to the requirements and limitations set forth in the Gas Tariff and Gas Sales and Transportation Operating Procedures during this past winter.

24. Description and status of efforts to verify customer alternative fuel availability and equipment testing, including:

a. Methods utilized to verify dual-fuel customers' capabilities, including power generation customers.
b. Please provide the results of compliance with the interruptible rules during last winter. Be sure to include the number of customers switched to firm service or removed from gas service due to non-compliance.
c. How many customers will be visited out of how many customers in total? Will all customers with non-compliance issues last winter be visited? How often will the complaint customers be visited?
d. What are the alternate fuels and how many customers are in each fuel category?
e. Are affidavits required?
f. Outcome of review? Rechecks?
g. Provide a copy of this year's (if available) and last year's pre-season lette r(s), if applicable. Have you made or are you planning to make any changes to these letters based on the events of the 2017-18 heating season? If yes, what are the changes?
h. Did your experience servicing dual fuel customers during last winter indicate the need for additional alternate fuel inventory requirements ? Is so, what changes do you recommend?
i. Is the company aware of any issues regarding interruptible customers not receiving their oil deliveries during the winter season? If so, please provide details of when and where this occurred, as well as what the company would suggest could be done to help these customers.
j. Will you be modifying your procedures for verifying alternate fuel inve ntories being held by interruptible customers (including generators and temperature- controlled customers) as a result of the winter of 2017-2018? If

so, how? If **affidavits are not used, explain why not?**

Response 24

a. Methods utilized to verify dual-fuel customers' capabilities, including power generation customers.

Response 24a

Both CECONY and O&R require affidavits for all interruptible customers attesting to compliance with LDC tariffs and include customer's oil dealer's contact information.

In July, CECONY will send a letter to all interruptible and off-peak firm customers providing the most recent contact information on record and asking them to update their contact information as necessary.

CECONY will notify all interruptible gas customers via certified letter or electronically of any changes to the operating requirements for the 2018-19 winter heating season. The letters will be sent to customers at the end of August or by mid-September at the latest and will include the current rates and charges for any unauthorized gas use, telephone and contact information of who to call in the event an equipment failure prevents a customer from switching to its alternate fuel or energy source, and an Affidavit form. CECONY will conduct a communications test at the end of October, followed by a planned gas interruption during the month of November which is subject to unauthorized use charges. CECONY will also notify Heating Oil Providers by mid-November via e-mail of a point of contact they can use to report any supply or transportation logistical issues. In addition, CECONY provides an eLearning tool on their web sites for use by the Interruptible customers which is intended for training purposes. Any customer not in compliance with the terms and conditions of the Service Class during a planned interruption will be subject to unauthorized use charges and a strike or equipment waiver under the Two Violation Rule.

O&R will notify all interruptible gas customers via certified letters, return receipt requested, of any changes to the operating requirements for the 2017-18 winter heating season. The letters will be mailed out mid-September and will include the current rates and charges for any unauthorized gas use, as well as telephone numbers and contact personnel to call in the event that an equipment failure prevents a customer from switching to its alternate fuel or energy source. O&R plans to conduct a test of their communication systems at the end of October, followed by a planned gas interruption during the month of November. The intent of a planned interruption is to verify the customer's ability to comply with the requirements and restrictions on the use of gas during an interruption. Any customer not in compliance with the terms and conditions of the Service Class during a planned interruption will be subject to unauthorized use charges and a strike or equipment waiver under the Two Violation Rule. In addition O&R provides an eLearning tool on their web sites for use by the Interruptible customers. This eLearning tool is intended for training purposes and to assist interruptible customers in understanding their responsibilities as gas customers taking service under the dual fuel interruptible gas provisions. O&R customers are reminded to review the eLearning tool through information provided by mail and provided during site visits. Annual O& R Customer meetings will be conducted as necessary to convey new policies, tariff changes, or other important information as needed. In the absence of material changes to policies or tariff, the eLearning tool is available to O&R Customers on line to refresh the Customers' understanding of the interruptible programs' terms and conditions. Upon request by the O&R Customer, a Major Account Engineer will meet with the Customer to provide additional information or answer any questions the customer may have regarding the terms and conditions of the interruptible customer program.

The CECONY and O&R Gas Control Department maintain an up-to-date telephone and email listing for all Power Generation gas customers that contains all on-site and off-site personnel that are available 24/7.

Power Generation Customers are required to provide alternate fuel capability affidavits on an annual basis.

b. Please provide the results of compliance with the interruptible rules during last winter. Be sure to include the number of customers switched to firm service or removed from gas service due to non-compliance.

<u>Response 24b</u>

CECONY interruptible compliance results were:

- November 8, 2017 for a total of 4 hours – 14 customer violations
- December 27, 2017 for a total of 288 hours – 28 - customer violations – 2 customers transferred to firm rate

In addition to the two (2) customers listed above that were transferred to firm rate due to 2-strike violations, there were also 4 Temperature Control customers who were transferred to a firm rate due to 2-strike violations, and 5 customers who voluntarily transferred to a firm rate. In total, these transfers contributed a nine (9) mdt/day increase to the Company's peak day.

O&R had 89 interruptible service accounts for the 2017-2018 season. O&R experienced 3 interruptions during that period which are as follows:

November 30, 2017 total of 6 hours (system compliance) - one customer violation.
December 31, 2017 total of 48 hours (system compliance) - one customer violation.
January 5, 2018 total of 48 hours (system compliance) - five customer violations

There was one customer that had two strikes and moved to firm gas service

c. How many customers will be visited out of how many customers in total? Will all customers with non-compliance issues last winter be visited? How often will the complaint customers be visited?

<u>Response 24c</u>

The Companies require Interruptible and Off-peak firm customers to fill out, sign and return an affidavit (which is included in the pre-season letter) attesting that they have executed contracts with one or more suppliers for their alternate fuel to provide for the delivery of such alternate fuel during the 2018-19 Winter Season in quantities sufficient to meet the customer's alternate fuel reserve requirement, or that they will shut down their business operations during periods of interruption.

CECONY will send a broadcast e-mail to all customers who do not respond to the pre-season letter as agreed to in the Joint Proposal of the rate case effective October 1, 2010.

The Companies also provide a follow-up contact for those customers that do not return an executed affidavit.

In addition, O&R performs pre-season customer site inspections, representing 60% of the interruptible load or on average, 10-20 customer site inspections per year. Customers who may have had problems interrupting the year prior will also be included in these inspections.

d. What are the alternate fuels and how many customers are in each fuel category?

Response 24d

In CECONY's service area, 487 customers use No. 2 oil, 76 customers use No. 4 oil, and 18 customers use No. 6 oil. One customer uses electric and 1 customer uses waste oil. The total number of customers is 583.

In the O&R service area, 86 customers use No. 2 oil and 3 customers utilize propane as an alternate fuel totaling 89 customers.

e. Are affidavits required?

Response 24e

As indicated in Response 24c, CECONY and O&R customers are required to return affidavits that are contained in the pre-season letter in which they indicate their alternate fuel supply capability or shut down option.

f. Outcome of review? Rechecks?

Response 24f

Both Companies re-check all customers that had previous communications and/or mechanical problems, and reiterates the importance of being compliant in order to avoid the risk and cost of being returned to firm service. CECONY and O&R utilize the planned interruption during the month of November to verify the customer's ability to comply with interruption requests.

g. Provide a copy of this year's (if available) and last year's pre-season letter(s), if applicable. Have you made or are you planning to make any changes to these letters based on the events of the 2016-17 heating season? If yes, what are the changes?

Response 24g

The 2017-18 CECONY and O&R pre-season letters are included as an attachment. The 2018-19 pre-season letters are not available at this time.

h. Did your experience servicing dual fuel customers during last winter indicate the need for additional alternate fuel inventory requirements? Is so, what changes do you recommend?

Response 24h

The Companies did not experience any problems servicing dual fuel customers during last winter. Response 24i provides detail.

The Companies will follow the Communication Protocols in compliance with Commission Order in Case 15-G-0185.

i. Is the company aware of any issues regarding interruptible customers not receiving their oil deliveries during the winter season? If so, please provide details of when and where this occurred, as well as what the company would suggest could be done to help these customers.

Response 24i

In CECONY's service area there was a 12-day interruption during the period 12/27/17 – 1/8/18. After 10 days we did get reports from some customers that they were anxious about waiting for oil deliveries because their tanks were getting low. One customer reported only being able to get half of their delivery. We should continue to work closely internally to monitor the system during these times and work closely, as we have been doing, with PSC Staff during the cold weather calls with other downstate utilities and the oil industry.

In Orange and Rockland service area, there were no customers who reported running out of oil.

j. Will you be modifying your procedures for verifying alternate fuel inventories being held by interruptible customers (including generators and temperature-controlled customers) as a result of the winter of 2016-2017? If so, how? If affidavits are not used, explain why not?

Response 24j

The Companies will not be modifying procedures as a result of the winter of 2017-18. CECONY did file modifications to its GTOP in February 2017 to comply with Order 15-G-0185 (Interruptible Communication Protocol).

25. Describe the methods used to communicate with interruptible customers, their marketers/fuel suppliers, NYSERDA and the various Oil Associations in New York prior to, and during, periods of interruption in compliances with Commission Order in Case 11-0-0543.

Response 25

In preparation of the winter, CECONY will send a letter to all interruptible and off-peak firm customers in July providing the most recent contact information on record and asking them to update their contact information as necessary. The Companies will conduct a communications test at the end of October. The Companies will also notify Heating Oil Providers by mid-November via e-mail of a point of contact they can use to report any supply or transportation logistical issues.

During the winter, CECONY will provide a minimum of eight hours advance notice of a service interruption; and to the extent practicable for the notice to be provided during business hours; to all interruptible sales and transportation customers, including Customers electing the Shut-Down Option using three (3) of the form/modes provided by the Customer as follows; (i) by telephone: the Company will provide telephone notification of a service interruption to the Customer for up to three (3) different telephone numbers provided by the Customer. The notification will provide the date and time of an interruption and any necessary CECONY contact information; (ii) by fax: a fax message containing interruption information will be sent to each customer selecting this mode of notification using up to three (3) fax numbers, (iii) email: an email notice containing interruption information will be sent to each Customer selecting this notification mode (the Company will accept three (3) individual email addresses per notice. After that, Customers can provide a single "point of contact" in the form of an internal distribution list); (iv) text message: a text message containing interruption information will be sent to each Customer selecting this mode using up to three text message numbers. In addition, e-mail notifications are sent to marketers/fuel suppliers, NYSERDA, PSC Staff and the various Oil Associations in New York. During the Winter Period, CECONY will maintain a telephone hotline where a customer can obtain information on a pending or existing interruption and/or leave a message if necessary. In addition, customers can always contact us at our dedicated email address: em-gasinterruptions@coned.com.

O&R provides at minimum, four hours advance notice of a service interruption to interruptible and off-peak firm customers, as well as affected marketers. Customer notification by O&R will be made by telephone, email and text message using Twenty First Century VRU application. The Customer may elect any or all of the three options as a means of communication. The contacts will be updated annually by the customer. O&R will communicate using various messages to the customers, such as;

1) Early warnings (if time permits)
2) Start of the interruption period
3) Updates during the interruption period
4) End of the interruption period

In each message, customers are informed of a hotline available for additional information, questions, or concerns. Additionally, customers are encouraged to contact their designated Major Account Engineer for further assistance if necessary.

In preparation for these communications, O&R will annually contact customers for accurate and up-to-date contact information and telephone numbers. Thereafter, O&R will perform a communication test to each customer to verify that a successful contact can be made. If a successful contact was not made during the communications test, O&R will follow up and address any issues with the customer.

26. Please provide the total number of firm dual fuel and interruptible customers, by service class, including how many interruptible are temperature controlled. How will the switch to their alternate fuel be accomplished and ensured? Please indicate the number of process customers that are exempt from maintaining alternate fuel supplies and have indicated intention to do so, and provide a copy of the affidavit to

Case 18-M-0272
Submission Date July 16, 2018
Version #:1

be submitted by those customers. Please provide a copy of the letter that will be sent to all dual fuel customers if there are five or more interruptions prior to February 15, per Commission Order in Case 11-0-0543.

Response 26

CECONY currently has a total of 583 interruptible and off-peak firm gas customers: 216 are SC 12 Rate 1 of which 89 customers choose temperature control as their method of interruption; and 53 are SC 12 Rate 2. CECONY also has approximately 330 firm dual fuel customers. See response number 25 which describes the communication protocol. CECONY has about 11 process customers and currently none of those customers chose the shut-down option. A sample copy of the letter that will be sent to dual fuel customers if there are five or more interruptions prior to February is attached. At the conclusion of each notification customer interruption, the Company advises customers to inventory their alternate fuel supply levels for replenishment to meet future interruption needs for the remainder of the winter season. In addition, the Companies will issue periodic communications during an interruption anticipated to last more than seven (7) days to remind customers to replenish inventories as needed to maintain minimum levels.

Temperature controlled customers have equipment on site to automatically switch to their alternate fuel when a certain temperature is reached. All notification customers require the customer to ensure they have switched over to their alternate fuel.

None of O&R's 89 interruptible customers are temperature controlled. None of O&R's interruptible customers are exempt from maintaining their alternate fuel supply.

27. A current organization chart for your company's gas supply department. Please include a list of contact people for the winter season for updated storage, peaking and other supply related information. Include the chief dispatcher and telephone numbers for both weekdays and weekends.

Response 27

A chart depicting Gas Supply's organization is included as Exhibit 4.

The table below lists the people that staff can contact in reference to supply information

Name	Title	Office	Mobile Phone
Kathleen Trischitta	Director, Gas Supply	(212) 466-8216	(914)-760-3249
Anthony Castellano	Sec. Manager, Gas Purchasing	(212) 466-8278	(914)-755-4428
Victor Dadario	Dep't Mgr., CECONY Gas Control	(718) 794-2873	(917) 217- 7554
Kenneth Fulton	Dep't Mgr., O&R Gas Control	(718) 794-2876	(646)-942-8011
CECONY Gas System Operator	CECONY Gas Control (24 hours)	(718) 794-2900	

Case 18-M-0272
Submission Date July 16, 2018
Version #:1

O&R Gas System Operator	O&R Gas Control (24 hours)	(718) 794-2889	
Aristides Flores	Sec. Manager, LNG Facility	(718) 204-4389	(347) 203-2877

28. Please provide the following information on conversions to natural gas:
a. Requests received per year, for the last five years, from customers using heating fuels other than natural gas. Provide the data broken down between residential and non-residential customers. If there has been an increase in requests, how is the company handling such an increase?
b. Do you see new opportunities to expand gas services, regardless of the ever changing cost differential between natural gas and its alternatives? If so, please explain any plans and the expected number of customer conversions. Please outline coordination of these activities with Case 12-0-0297, which is investigating expansion of the natural gas system in New York State.
c. Identify any areas within your service territory where you have placed a moratorium on the addition of new customers, new service or any restrictions on existing services. Describe the reasons why such a restriction is necessary.
d. Please provide a list of Title V air permit holders in your service territory (available on the DEC website) and indicate whether there is currently natural gas service to each.
e. If you serve customers in the New York City area, describe your analysis and the impacts to your system of the city' s anticipated proposal to require larger buildings to convert from heavy fuel oils (#4 and #6) to lighter oil (#2 and bio-fuels) and/or natural gas for space heating.
f. Please provide a list of natural gas distribution system expansion projects, including new franchise opportunities, which are being pursued in the next five years. If there are none, please explain how this is justified given the Commission's stated goal of expanding the natural gas system in New York State.
g. Please provide a 3-year forecast of all projects advancing REV clean energy/demand response natural gas solutions.
h. Please identify any potential use of renewable gas resources, **or demand response program proposals that may address capacity or pressure constrained service areas,** that could be utilized to reduce peak day demand and alleviate the need for additional interstate pipeline capacity **or gas distribution network upgrades.**
i. Please identify any potential use of CNG or LNG as a NPA to alleviate the need for additional interstate pipeline capacity or gas distribution network upgrades.

<u>Response 28</u>

a. Requests received per year, for the last five years, from customers using heating fuels other than natural gas. Provide the data broken down between residential and non-residential customers. If

Case 18-M-0272
Submission Date July 16, 2018
Version #:1

there has been an increase in requests, how is the company handling such an increase?

Response 28a (Business Confidential)

The table below shows the CECONY conversion requests for the past 5 years:

[redacted]

*Requests are for conversion in NYC only

The table below shows the O&R conversion requests for the past 5 years:

[redacted]

b. Do you see new opportunities to expand gas services, regardless of the ever changing cost differential between natural gas and its alternatives? If so, please explain any plans and the expected number of customer conversions. Please outline coordination of these activities with Case 12-G-0297, which is investigating expansion of the natural gas system in New York State.

Response 28b (Business Confidential)

CECONY and O&R continue to support expansion of gas infrastructure to provide consumers access to a clean, economical fuel source subject to available pipeline capacity and the exploration of potentially cleaner alternatives. CECONY and O&R pursue expansion in accordance with the following guiding principles:

- [redacted]

[redacted]

[redacted]

[redacted]

c. Identify any areas within your service territory where you have placed a moratorium on the addition of new customers, new service or any restrictions on existing services. Describe the reasons why such a restriction is necessary.

Response 28c

The Companies do not have any moratoriums in place, at this time.

d. Please provide a list of Title V air permit holders in your service territory (available on the DEC website) and indicate whether there is currently natural gas service to each.

Response 28d

A table with the list of all Title V air permit holders in our service territory is included as Exhibit 5.

Of the Title V permit holders currently listed on the DEC website, we identified 38 permit holders in the CECONY gas service territory. Of the 38 air permit holders in the CECONY gas service territory, 26 have a physical gas service to their property.

For Orange & Rockland, the Company has identified 15 air permit holders, 10 of which have a physical gas service to their property.

e. If you serve customers in the New York City area, describe your analysis and the impacts to your system of the city's anticipated proposal to require larger buildings to convert from heavy fuel oils (#4 and #6) to lighter oil (#2 and bio-fuels) and/or natural gas for space heating.

Response 28e

On April 20, 2011, the New York City Department of Environmental Protection passed a rule governing the emissions from the use of #4 and #6 fuel oil in heat and hot water boilers and burners.

In order to improve the air quality of the City, the Department of Environmental Protection is amending Chapter 2 of Title 15 of the Rules of the City of New York to prohibit the use of fuel oil grade numbers 4 and 6 in heat and hot water boilers and burners, unless it can be demonstrated that the emissions of Particulate Matter (PM) and Oxides of Nitrogen (NOx) are equivalent to or cleaner than set fuel types.

For owners with an existing operating permit, it requires boilers to use fuel oil grade #2, #4 and/or natural gas in order for applicants to receive a renewed Certificate of Operation. Boilers that use fuel oil grade #6 will not receive a renewed Certificate of Operation unless the applicant demonstrates that the fuel oil grade #6 that will be used will emit the same or less PM and NOx than fuel oil grade #4 on an annual basis. The use of #6 heating oil was phased out in June 2015, whereas #4 oil users have until 2030.

As of January 1, 2030, the rule requires boilers to use fuel oil grade #2 and/or natural gas in order for applicants to receive a new or renewed Certificate of Operation, unless the applicant demonstrates that the fuel oil grade #4 and/or #6 to be used will emit no more PM and NOx than fuel oil grade #2 on an annual basis. This schedule will provide owners with time to convert to fuel oil grade #2, or its equivalent, or natural gas, while ensuring more rapid transition from the most polluting fuel oil.

The following assessment only pertains to Con Edison's gas service territory in NYC:

The regulation impacts approximately 7,000 buildings in Con Edison's gas service area, of which the greatest building density is in Manhattan and the west Bronx for fuel oil grades #4 and #6. If all 7,000 affected buildings converted to using natural gas only, their aggregate peak usage would be approximately 600 MDt/day, or roughly 40% of current Con Edison's firm gas peak day usage. This demand would represent an annual (volume) use equivalent to 60 MMDt, or about 50% of firm gas demand. From 2011 to the present, the Company's estimate for #4 and #6 fuel oil to gas has increased the CECONY Gas Peak Demand by approximately **250** MDt/day. For NYC, we forecast approximately **50** MDt/day of additional increased Gas Peak Demand from the end of 2018 through 2038 for #4 and #6 fuel oil to gas conversions, with a the majority if this being realized over the next

5 years.

In the last couple of years we have seen a decline in the number of conversion requests driven by the price parity between oil and gas. However since the promulgation of the "Clean Heat regulation", we have successfully converted over 60% of buildings from #4/6 oils and almost 20% from #2 oil to natural gas.

Heavy fuel oil conversions have the potential to significantly raise natural gas usage in the Con Edison gas service area, particularly impacting system planning and reinforcement in low-pressure areas such as Manhattan. Accommodating this demand growth has significantly impacted infrastructure planning and reinforcement.

A large portion of the distribution system consists of low pressure mains, which are adequate for our current customer needs, but will require reinforcement to accept the new loads from oil conversions.

There are three techniques we could employ to reinforce an inadequate system:

Install regulators, where possible. Where there is a high pressure main nearby, we can connect a regulator and associated main ties/extensions to provide an additional supply point to the low pressure area;

Replace smaller diameter mains with larger diameter mains to add capacity; and,

Install new mains to supply new customers.

To minimize customer connection costs and to manage trenching costs, we have employed a customer aggregation or "area growth" strategy, whereby we encourage customers in close geographic proximity to convert at the same time. The objective of this strategy is to trench the street once and connect as many customers at one time to minimize costs and disruption to the community. This avoids repeated trenching efforts that would occur if customers in the same vicinity converted at different times.

f. Please provide a list of natural gas distribution system expansion projects, including new franchise opportunities, which are being pursued in the next five years. If there are none, please explain how this is justified given the Commission's stated goal of expanding the natural gas system in New York State.

Response 28f

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

g. Please provide a 3-year forecast of all projects advancing REV clean energy/demand response natural gas solutions.

<u>Response 28g</u>

For advancing REV-like solutions for electric:

The Company forecasts the amount of gas fired Distributed Generation/Combined Heat and Power (DG/CHP) in the CECONY and O&R service territories. This forecast is based on potential development of DG/CHP that are being considered and would require natural gas for Combustion Turbines, Internal Combustion Engines, Microturbines, and Fuel Cells. Such gas fired customer-sided projects would align with some of the attributes of the REV.

The current estimate in the CECONY Gas Peak Demand Forecast is for a total of approximately 14 MDt/day, which materializes from 2018 through 2020 and represents about 67 MW of natural gas fired DG/CHP capacity over the 3 year period. For gas fired DG/CHP outside of CECONY's gas service territory, but within CECONY's electric service territory (Brooklyn, Staten Island, and a large portion of Queens), the Company coordinates with National Grid/KEDNY for gas service.

The current estimate in the O&R Gas Peak Demand Forecast is for a total of approximately 0.4 MDt/day, which materializes from 2018 through 2020 and represents about 2 MW of natural gas fired DG/CHP capacity over the 3 year period.

For advancing REV-like solutions for gas:

For CECONY we forecast a total of approximately 170 MDt/day of EE, DR, and Smart RFP Solutions over the next the 20 year period and a total of approximately 86 MDt/day of Natural Conservation (Organic EE) over the next 20 year period.

For O&R we forecast a total of approximately 2 MDt/day of EE over the next the 20 year period and a total of approximately 9 MDt/day of Natural Conservation (Organic EE) over the next 20 year period.

h. Please identify any potential use of renewable gas resources, or demand response program proposals that may address capacity or pressure constrained service areas, that could be utilized to reduce peak day demand and alleviate the need for additional interstate pipeline capacity or gas distribution network upgrades.

Response 28h

CECONY is currently evaluating the use of renewable gas resources and demand response proposals as part of the Smart Solution Filing made in December 2017.

i. Please identify any potential use of CNG or LNG as a non-pipes alternative (NPA) to alleviate the need for additional interstate pipeline capacity or gas distribution network upgrades.

Response 28i

CECONY is using CNG to meet the needs of its gas customers in Westchester during cold weather periods. The CNG is able to provide up to 625 Mcfh of gas per hour with 4 hours of usage available on site and additional gas available through truck replacements. Please also see response to 28H.

Issue 4

Please provide the following information related to your company' s plans to diversify purchases and manage gas price risk:

29. A description of your company 's gas purchasing strategy, including:

a. Information regarding gas purchases for last year and any planned changes for this year. Did your experience during the winter of 2017-18 lead to any changes? If so, what are the changes? If not, why not? Please include an identification of the amount of Canadian, domestic gas (identify shale gas purchases if available) and **CNG/LNG purchased.**

b. The types of contracts and associated contract flexibility.

c. The extent of planned reliance on firm gas, spot gas, swing gas, etc.

d. The description of any triggers to purchase spot (daily) gas.

e. Pricing terms, indices , etc. of the contracts.

f. The liquid point(s) that you typically purchase at.

g. The effects that recent and proposed pipeline projects and new supply sources of gas have had on your current (and long-term) purchasing strategy. Includ e the breakdown of the volumes of gas purchased for the 2017-18 winter and projected for the 2018-19 winter purchases from the Northeast (Marcellus/Utica), mid- continent, Gulf and Canadian supply regions.

h. Strategy for using storage assets going forward in light of Marcellus area production, since what was once market area may now be considered production area.

i. Any analysis of your use of long-haul capacity versus short haul and/or local production going forward, including any contracts recently or planned to be

Case 18-M-0272
Submission Date July 16, 2018
Version #:1

converted from long-haul to short-haul.

Response 29

a. Information regarding gas purchases for last year and any planned changes for this year. Did your experience during the winter of 2016-17 lead to any changes? If so, what are the changes? If not, why not? Please include an identification of the amount of Canadian, domestic gas (identify shale gas purchases if available) and LNG.

b. The types of contracts and associated contract flexibility.

Response 29a and b (Business Confidential)

[redacted]

[redacted]

[redacted]

c. The extent of planned reliance on firm gas, spot gas, swing gas, etc.

d. The description of any triggers to purchase spot (daily) gas.

Response 29c and d (Business Confidential)

[redacted].

Case 18-M-0272
Submission Date July 16, 2018
Version #:1

e. Pricing terms, indices, etc. of the contracts.

<u>Response 29e (Business Confidential)</u>

To achieve fair market pricing, the Companies' supply contracts have pricing mechanisms that allow the option to trigger a NYMEX price, use a first-of-the month index price, or negotiate a month or longer fixed commodity price. A periodic redetermination of this mechanism helps ensure that the price and price formulas continue to reflect the market price for similar contract arrangements. The majority of Gas supply contracts are procured through a Request for Proposals (RFP) process for summer and winter supplies, which are administered by the Companies and through, ENERnoc, an on-line auction platform.

f. The liquid point(s) that you typically purchase at.

<u>Response 29f (Business Confidential)</u>

The Companies purchase natural gas at various liquid points in the production and the market areas. The following table summarizes these purchase points:

[redacted]	[redacted]	[redacted]
[redacted]		[redacted]
[redacted]	[redacted]	[redacted]
[redacted]		[redacted]
[redacted]		[redacted]
[redacted]		[redacted]
[redacted]		[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

g. The effects that recent and proposed pipeline projects and new supply sources of gas have had on your current (and long-term) purchasing strategy. Include the breakdown of the volumes of gas purchased for the 2016-17 winter and projected for the 2017-18 winter purchases from the Northeast (Marcellus/Utica), mid-continent, Gulf and Canadian supply regions.

Case 18-M-0272
Submission Date July 16, 2018
Version #:1

Response 29g (Business Confidential)

[redacted]

h. Strategy for using storage assets going forward in light of Marcellus area production, since what was once market area may now be considered production area.

Response 29h (Business Confidential)

[redacted]

[redacted]

i. Any analysis of your use of long-haul capacity versus short haul and/or local production going forward, including any contracts recently or planned to be converted from long-haul to short-haul.

Response 29i (Business Confidential)

[redacted]

Case 18-M-0272
Submission Date July 16, 2018
Version #:1

[redacted]

[redacted]

30. A description of your company's gas price risk management strategy, including answers to the following questions:
a. What percentage of your gas supply do you hedge (1) physically and (2) financially?
b. Please break this down between storage and fixed price contracts.
c. If you use fixed price contracts, how, when and in what increments are they purchased?
d. Plea se provide the breakdown between futures and options (include quantities of each type on an annual and winter season basis).
e. How do you finance your swap/futures? Do you pay for them at the time of purchase or delivery?
f. What types of options do you use?
g. Describe how you decide which types of options to use.
h. How much and what percentage of total gas costs, booked to the GAC, do you spend on options?
i. How far out, when, and in what increments do you purchase futures?
j. How has your hedging strategy changed in the past year? Did your experience during the winter of 2017-18 lead to any changes? If so, what are the changes? If not, why not?
k. Describe any lessons learned in the past year.
l. Do you calculate gas price volatility, if so how, where and what time period do you use?
m. How do you determine the success or failure of your hedging program?
n. Please provide internal reporting, oversight, and audit structure of your hedging program.
o. <u>Table 7</u>: Actual price hedging performance versus planned price hedging performance for last year, a summary of " lessons learned", and arrangements for this year. Include separate quantities for each hedging instrument.

a. What percentage of your gas supply do you hedge (1) physically and (2) financially?

<u>Response 30a (Business Confidential)</u>

[redacted]

Case 18-M-0272
Submission Date July 16, 2018
Version #:1

[redacted]

b. Please break this down between storage and fixed price contracts.

Response 30b (Business Confidential)

[redacted]

c. If you use fixed price contracts, how, when and in what increments are they purchased?
Response 30c (Business Confidential)

[redacted]

d. Please provide the breakdown between futures and options (include quantities of each type on an annual and winter season basis).

Response 30d (Business Confidential)

[redacted]

[redacted]

e. How do you finance your swap/futures? Do you pay for them at the time of purchase or delivery?

Response 30e (Business Confidential)

[redacted]

Case 18-M-0272
Submission Date July 16, 2018
Version #:1

[redacted]

[redacted]

f. What types of options do you use?

<u>Response 30f (Business Confidential)</u>

[redacted]

g. Describe how you decide which types of options to use.

<u>Response 30g (Business Confidential)</u>

[redacted]

h. How much and what percentage of total gas costs, booked to the GAC, do you spend on options?

<u>Response 30h (Business Confidential)</u>

[redacted]

i. How far out, when, and in what increments do you purchase futures?

<u>Response 30i (Business Confidential)</u>

[redacted]

j. How has your hedging strategy changed in the past year? Did your experience during the winter of 2017-18 lead to any changes? If so, what are the changes? If not, why not?

<u>Response 30j (Business Confidential)</u>

[redacted]

k. Describe any lessons learned in the past year.

Response 30k (Business Confidential)

[redacted]

l. Do you calculate gas price volatility, if so how, where and what time period do you use?

Response 30l (Business Confidential)

[redacted]

m. How do you determine the success or failure of your hedging program?

Response 30m (Business Confidential)

[redacted]

n. Please provide internal reporting, oversight, and audit structure of your hedging program.

Response 30n (Business Confidential)

[redacted]

[redacted]

Table 7: Actual price hedging performance versus planned price hedging performance for last year, a summary of "lessons learned", and arrangements for this year. Include separate quantities for each hedging instrument.

Response 30o (Business Confidential)

Case 18-M-0272
Submission Date July 16, 2018
Version #:1

See Table 7 as attached work sheet.

31. How has your use of local production/landfill/renewable gas changed over the past year? Please provide the average daily volumes of local produced gas acquired for the previous heating season and a forecast for the upcoming season. Also, include any plans to connect new or additional local production to your distribution systems. What percentage of your system throughput is local production? Include the total volume of locally produced gas that entered your system annually since 2008 until the present. How much of this gas is directly tied into your distribution system?

<u>Response 31 (Business Confidential)</u>

[redacted]

[redacted]

[redacted]

[redacted]

32. Identify when and how standards for connecting Renewable Natural Gas (RNG) projects will be filed with the Commission. If there are no plans to file RNG standards, please explain why.

Response 32

[redacted]

Issue 5
Please provide the following information related to the changing market conditions:

33. A discussion of the impacts of the convergence of the gas and electric markets in your company's service territory, including:
a. Increase in summer load from last year.
b. Changes in system operations from last year including how gas-fired electric generators' needs and behavior during last winter impacted your distribution system operations.
c. Need for distribution system facilities improvements.
d. Available information on generators' upstream capacity arrangements.
e. Relationship between your company and its electric, steam operations or affiliate- owned generation, including any peaking service agreements.
f. Distributed Generation/C HP, including any micro-grid applications, **and their impact on peak design-day forecasting. List all known planned projects and locations on the system.**
g. Provide a list of all electric generators in your service territory, and indicate whether or not they are currently attached to your distribution system. If so, indicate the maximum daily deliver y quantity of the generating station.
h. Outline typical communications between gas-fired generators in your service territory and your natural gas control center, and explain any improvements planned for those communications.

Response 33

a. Increase in summer load from last year.

Response 33a (Business Confidential)

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

b. Changes in system operations from last year including how gas-fired electric generators' needs and behavior during last winter impacted your distribution system operations.

Response 33b (Business Confidential)

Shown below is Electric and Steam Generation Top 10 List for Monthly & Daily gas usage:

[redacted]

[redacted]

[redacted]

Shown below is the combined Distribution and Electric / Steam Generation Top 10 List for Monthly & gas usage:

[redacted]

[redacted]

[redacted]

Shown below is the combined Distribution and Electric / Steam Generation Top 10 List for Hourly gas usage:

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

c. **Need for distribution system facilities improvements.**

Response 33c (Business Confidential)

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Case 18-M-0272
Submission Date July 16, 2018
Version #:1

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

d. Available information on generators' upstream capacity arrangements.

<u>Response 33d (Business Confidential)</u>

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

e. Relationship between your company and its electric, steam operations or affiliate-owned generation, including any peaking service agreements.

<u>Response 33e</u>

[redacted]

[redacted]

Case 18-M-0272
Submission Date July 16, 2018
Version #:1

f. Distributed Generation/CHP, including any micro-grid applications.

Response 33f (Business Confidential)

[redacted]

[redacted]

NOTES

**……Maximum gas burning capability as interruptible customers

Shown below is a table that breaks down the distributed generation customers by unit type.

[redacted]

Case 18-M-0272
Submission Date July 16, 2018
Version #:1

[redacted]

g. Provide a list of all electric generators in your service territory, and indicate whether or not they are currently attached to your distribution system. If so, indicate the maximum daily delivery quantity of the generating station.

Response 33g (Business Confidential)

Listed below are the electric generators in the CECONY and O&R service territory. The generators are attached to the Companies' high pressure transmission facilities.

[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

[redacted]	[redacted]
[redacted]	[redacted]

h. Outline typical communications between gas-fired generators in your service territory and your natural gas control center, and explain any improvements planned for those communications.

<u>Response 33h (Business Confidential)</u>

[redacted]

Case 18-M-0272
Submission Date July 16, 2018
Version #:1

34. A discussion of the realized and expected impacts on gas prices, gas price volatility, and required upstream assets from recent and proposed pipeline expansions and the development of Northeast (Marcellus/Utica) shale gas wells and related infrastructure.

Response 34 (Business Confidential)

[redacted]

[redacted]

35. Please discuss any other major projects that will affect your purchasing strategy over the next five years and your anticipated responses to these changes.

Response 35 (Business Confidential)

[redacted]

[redacted]

[redacted]

36. Currently, how much natural gas is being sold on an annual basis for use in natural gas vehicles? How has this changed over the past few years and how do you anticipate that this will change over the five year planning period in your service territory?

Response 36 (Business Confidential)

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Case 18-M-0272
Submission Date July 16, 2018
Version #:1

37. Have you been approached by or had any discussions with outside entities regarding the construction of compressed natural gas (CNG) or liquefied natural gas (LNG) fueling stations? If so, please explain. What impediments do you see for the expansion of CNG and LNG transportation?

Response 37

[redacted]

[redacted]

[redacted]

38. Please list potential pipeline projects you are interested in, identifying the pipeline, delivery point, and daily delivery quantity you might take. Provide a list of all pipelines that you are communicating with on a regular basis regarding expansion projects on their pipeline systems that might be filed with the Federal Energy Regulatory Commission.

Response 38 (Business Confidential)

[redacted]

Issue 6

Please provide the following information regarding bill impacts:

Case 18-M-0272
Submission Date July 16, 2018
Version #:1

39. Table 8: Bill impact comparison of last winter versus the forecasted 2018-19 winter. lnclude the work papers used to develop Table 8 (note: they should also tie to the numbers in Table 7).

Response 39

Table 8 has the bill comparison.

Table 1

[redacted]

Table 2

[redacted]

[redacted]

[redacted]

[redacted]

Table 3

[redacted]

[redacted]

[redacted]

[redacted]

Table 4

[redacted]

Case 18-M-0272
Submission Date July 16, 2018
Version #:1

Table 5

[redacted]

Exhibit 1

[redacted]

[redacted]

[redacted]

[redacted]

Case 18-M-0272
Submission Date July 16, 2018
Version #:1

Exhibit 2

[redacted]

Exhibit 3

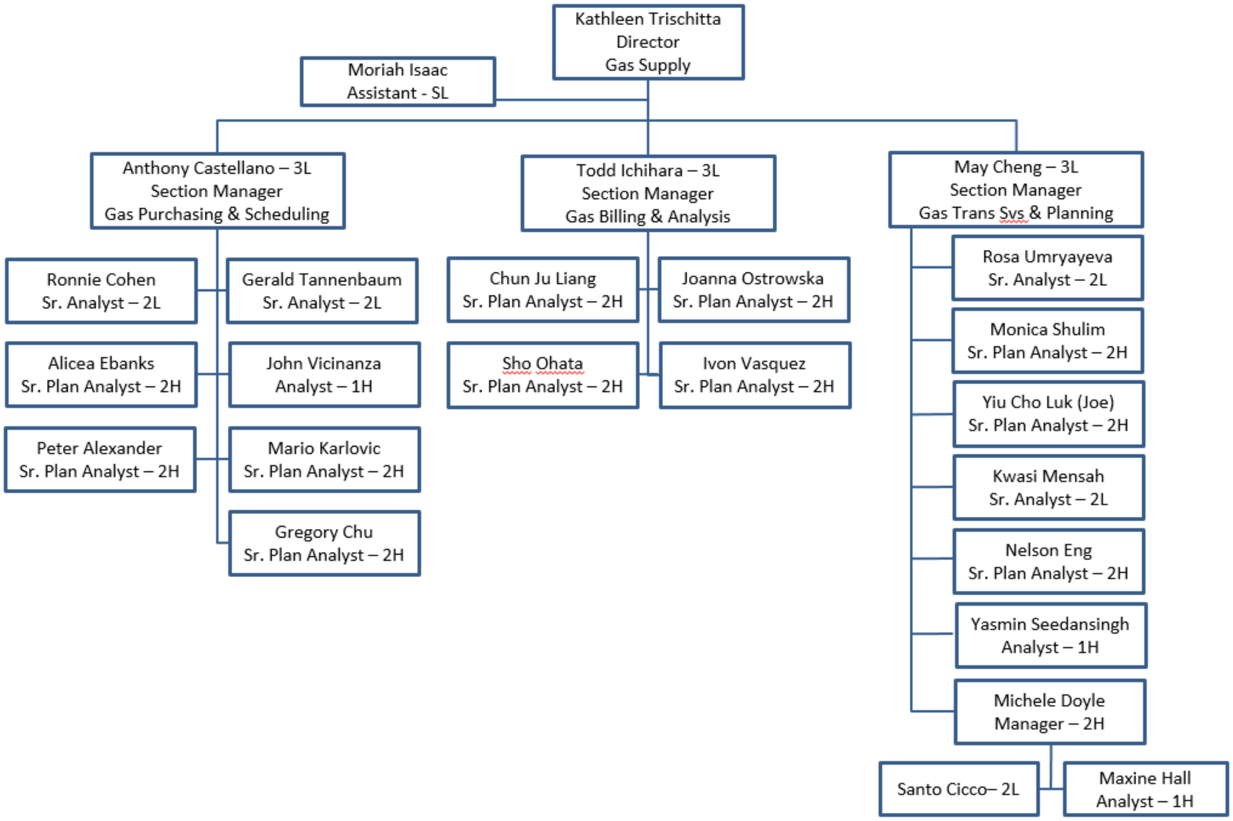
[redacted]

Exhibit 4

Case 18-M-0272
Submission Date July 16, 2018
Version #:1

Exhibit 4

Gas Supply Organizational Chart



Case 18-M-0272
Submission Date July 16, 2018
Version #:1

Exhibit 5

[redacted]

[redacted]

Table 7

Case 18-M-0272
Submission Date July 16, 2018
Version #:1

Table 7 - Winter Supply Hedges Summary

[redacted]

Case 18-M-0272
Submission Date July 16, 2018
Version #:1

Table 8

Case 17-M-0280 - Winter Supply 2018-19 Forms

Table 8 - Bill Comparison (Excluding Taxes)

Winter 2017-18 to Winter 2018-19

Company: Consolidated Edison Company, Inc.
Submission Date: 6/25/2018
Version #: 1

1	2	3	4	5	6
Company	2017-18 Average Residential Heating Customer Winter Bill	2017-18 Average Residential Heating Customer Winter Bill	2018-19 Forecasted Residential Heating Customer Winter Bill	Commodity Related Percent Change from Last Winter	Expected Percent Change from Last Winter
	Actual	Normalized	Normalized	(column 4 - column 3) / column 3	(column 4 - column 2) / column 2
Usage (Therms/Ccf)	907	842	842		
Total Delivery Costs	$825	$784	$844	7.8%	2.4%
Total Capacity Costs	$134	$124	$133	7.0%	-0.5%
GAC Costs (Commodity)	$261	$242	$277		
1 GAC Reconciliation	$20	$19	$36		
GAC Surcharges and Refunds	$48	$49	$0		
Total Commodity Costs	$329	$310	$313	1.0%	-5.0%
Total Winter Bill	**$1,288**	**$1,218**	**$1,290**	6.0%	0.2%

Assumptions:

Normal = 1,175 Therms/year with 842 Therms of winter use

Last Year Actual = 907 Therms of winter use

Notes:

[1] Identify the impact of any GAC reconcilliation surcharge or refund mechanism.

[2] Identify the impact of any other surcharges or refunds included in bills.

Make up of Monthly Bill Impact - ________	6.0%
1 Delivery	3.7%
2 GRT	0.3%
3 Monthly Rate (MRA) Adjustment	0.3%
4 Gas Cost Factor	1.0%
5 Systems Benefits Charge	-0.6%
6 Merchant Function Charge	0.0%
7 Revenue Decoupling Mechanism (RDM)	1.5%
8 Temporary NY State Surcharge	-0.2%
9 Other	0.0%
	6.0%

Case 18-M-0272
Submission Date July 16, 2018
Version #:1

Case 17-M-0280 - Winter Supply 2018-19 Forms

Table 8 - Bill Comparison (Excluding Taxes)

Winter 2017-18 to Winter 2018-19

Company: Orange and Rockland Utlities, Inc.
Submission Date: 6/25/2018
Version #: 1

1	2	3	4	5	6
Company	2017-18 Average Residential Heating Customer Winter Bill	2017-18 Average Residential Heating Customer Winter Bill	2018-19 Forecasted Residential Heating Customer Winter Bill	Commodity Related Percent Change from Last Winter	Expected Percent Change from Last Winter
	Actual	Normalized	Normalized	(column 4 - column 3) / column 3	(column 4 - column 2) / column 2
Usage (Therms/Ccf)	817	814	814		
Total Delivery Costs	$791	$788	$740	-6.1%	-6.4%
Total Capacity Costs	$49	$49	$53	8.9%	8.5%
GAC Costs (Commodity)	$235	$234	$268		
1 GAC Reconciliation	$5	$5	$31		
GAC Surcharges and Refunds	$43	$47	$0		
Total Commodity Costs	$283	$287	$299	4.1%	5.4%
Total Winter Bill	**$1,123**	**$1,124**	**$1,092**	-2.8%	-2.8%

Assumptions:

Normal = 1,146 Ccf/year with 814 Ccf of winter use

Actual Last Year = 817 Ccf of winter use

Notes:

[1] Identify the impact of any GAC reconcilliation surcharge or refund mechanism.

[2] Identify the impact of any other surcharges or refunds included in bills.

Make up of Monthly Bill Impact - ____	-2.8%
1 Delivery	0.0%
2 GRT	0.1%
3 Monthly Rate (MGA) Adjustment	-3.7%
4 Gas Cost Factor	1.4%
5 Systems Benefits Charge	0.0%
6 Merchant Function Charge	0.0%
7 Revenue Decoupling Mechanism (RDM)	-0.5%
8 Temporary NY State Surcharge	-0.2%
9 Other	0.0%
	-2.8%

Case 18-M-0272
Submission Date July 16, 2018
Version #:1

Pre- Season Letter

conEdison
a conEdison, inc. company

Consolidated Edison Company
of New York, Inc.
4 Irving Place
New York NY 10003
www.conEd.com

<<CUST_ NAME>>
<<MLAD_1>>
<<MLAD_2>>
<<MLAD_3>>

September XX, 2017

Re: Customer Acct. #: <<ACCT_NO>>
Service Address: <<SADD>> <TOWN>><<ZIP>>
Service Classification – SC# <<GSSC>>

Dear Interruptible Gas Customer:

The winter heating season is approaching quickly. This letter is to remind you that it is time to assess your winter fuel supply requirements. Your primary responsibility as a Con Edison interruptible gas customer is to comply with and respond to any directive to interrupt your gas service initiated by Con Edison by switching to your alternate fuel in accordance with Service Classification ("SC") Nos. 9 or 12 of the Company's Gas tariff which is available for viewing at www.coned.com .

As an interruptible gas customer that chooses temperature-control as your method of interruption, you must immediately stop using natural gas and switch to your alternate fuel or alternate energy source according to the following schedule. **Please note that the temperature setting has been revised upward by 1 degree F from last year's setting. Please be sure to reset your automated temperature-sensing equipment to the new temperature.**

	Stop Using Gas	Resume Using Gas
SC 9/12 Rate 1	**21 degrees F**	**26 degrees F**

If you purchase your gas from a Gas Marketer you are required to inform your Supplier that you have chosen the temperature control option and; in addition, you must immediately stop using natural gas and switch to your alternate fuel or alternate energy source according to the schedule above or, at a higher temperature if notified by the Company to do so.

Temperature Sensing Equipment: Please check that your temperature-sensing equipment is in working order and set to the temperature listed in the above box.

Customer Affidavits: Attached you will find your Customer Affidavit which you are required to complete, sign, and have notarized by close of business on **October 1, 2017**. **You must return this form with all the required information including the name and email contact information for your Alternate Fuel Supplier. If you do not return the affidavit with the required information you will not be eligible for the Interruptible Rate under SC9 and SC12.** Please e-mail the completed Affidavit form to EM-Affidavit@coned.com. **Please Note: the Shut-Down Option will only apply to customers who meet the criteria listed on the Affidavit under that section. Otherwise, please fill out the Alternate Fuel/Energy Source Option of the Affidavit.**

Customer Responsibility: You must have adequate reserves of your alternate fuel or alternate energy source available and have your dual fuel equipment and associated telephone lines in proper working order. In addition, you must replenish your fuel inventory during and after an interruption to the extent necessary, to operate your facilities satisfactorily, without gas whenever and so long as service is interrupted. **You must return your Customer Affidavit or you will not be eligible for the applicable rate as stated above.**

Customer Communications: *(THIS SECTION IS APPLICABLE TO EXISTING TRANSPORTATION CUSTOMERS WHO BUY THEIR GAS FROM A MARKETER AND CHOOSE TEMPERATURE CONTROL AS THEIR METHOD OF INTERRUPTION)* Notification of an interruption will be via telephone, fax, e-mail and text message and will be issued with no less than eight (8) hours advance notice. You may not resume burning natural gas until you are notified (by automated telephone, fax, e-mail or text message) to do so by the Company.

E-Mail Requirement: – You **must** provide the Company with an e-mail address for your account to help us expedite electronic communication.

Communications Test: the Company will conduct a test of its communication system at the end of October.

Page 2

Planned Interruption: *(THIS SECTION IS APPLICABLE TO EXISTING TRANSPORTATION CUSTOMERS WHO BUY THEIR GAS FROM A MARKETER AND CHOOSE TEMPERATURE CONTROL AS THEIR METHOD OF INTERRUPTION)* A planned interruption will be conducted by the Company in early November. Please be prepared for the planned interruption as failure to comply will result in the assessment of charges for unauthorized gas use and other applicable charges and/or consequences.

Unauthorized Gas Use Charges: the higher of (i) two times the sum of the market gas price as determined in accordance with the Company's Sales and Transportation Operating Procedures plus the applicable interruptible or off-peak firm transportation rate; or (ii) nine times the applicable interruptible or off-peak firm sales rate.

E-Learning FAQ: *(THIS SECTION IS APPLICABLE TO EXISTING TRANSPORTATION CUSTOMERS WHO BUY THEIR GAS FROM A MARKETER AND CHOOSE TEMPERATURE CONTROL AS THEIR METHOD OF INTERRUPTION)* Our eLearning FAQ is always available to assist you in understanding your responsibilities and will guide you through the notification process. You can access the eLearning FAQ by visiting our website at www.coned.com – choose "Become An Energy Service Company Partner towards the bottom of the page on the right side – then click on **"How To Become a Gas Supply Company"** – scroll to the bottom of the page and click on "**FAQ**" or you can use the direct link: https://www.coned.com/en/business-partners/how-to-become-a-gas-supply-partner/page-data/duel-fuel-faq. We are including in this letter a list of Operating Suggestions and Service Requirements for your use.

Gas Interruption Hotline: During the winter months, our **Gas Interruption Hotline at 212-460-3459** is available to provide additional information on the status of gas service interruptions. You can also contact us at EM-GasInterruptions@coned.com.

As a valued Con Edison gas customer, please be assured that we very much want to help you minimize your fuel costs and that we are ready to assist you to make your interruptible gas service as convenient and economical as possible. At the same time, your full compliance with the Company's gas interruption procedures is necessary for the integrity of the Company's gas system and the reliability of the Company's service to customers without dual-fuel capability. If you have any questions about any of these matters, please contact me at 212-460-6920 or at camellom@coned.com.

Sincerely,

Michael Camello

Michael Camello
Enclosures

conEdison

Con Edison Operating Suggestions and Service Requirements for Interruptible and Off-Peak Firm Gas Customers

- Ensure that your dual fuel equipment is in good working order and that a sufficient reserve of your alternate fuel or alternate energy source is always available.
- Designate a responsible individual to inspect your equipment every time an interruption of gas service is necessary to ensure the equipment is not operating on natural gas.
- Be prepared to switch to your alternate fuel or alternate energy source at any time upon notification from Con Edison, **even on holidays (see holidays observed by Con Edison on right)**.
- Admit Con Edison employees promptly to your premises for any necessary inspections of your gas usage equipment and controls.
- Notify Con Edison immediately of any emergency situation involving your gas service; or, if a condition develops that prevents you from switching to your alternate energy source. You can call the **GAS INTERRUPTION HOTLINE** at **(212) 460-3459** and leave a message. If necessary, someone will call you back. During the off-hours you can call **718-794-2900 / 2903 / 2904**. The **Gas Interruption Hotline** is activated for the entire heating season to provide you with information on interruptions and for you to leave a message, if necessary.
- **Two Violation Rule** – during the heating season, if you fail to fully interrupt your use of gas (except for any permitted use of gas for ignition purposes - maximum of 2 therms per hour) for two (2) interruption periods (including any planned interruption), the Company will notify you in a certified letter, return receipt requested that it will transfer you to the applicable firm service classification commencing with the billing month following the month in which the second violation occurs unless you choose to terminate your service at that time. ***Failure to interrupt your use of gas due to inoperable dual-fuel facilities counts as a violation towards the two-violation rule with one exception for each heating season.***
- Here is the criteria for one equipment failure exception to the Two Violation Rule:

On one occasion during each heating season a customer's failure to interrupt the use of gas due to documented inoperable dual-fuel facilities will not be counted as a violation provided that you:

(a) notify the Company within one hour of the failure of your equipment. You can do this by calling the **GAS INTERRUPTION HOTLINE** at **(212) 460-3459**. You can leave a message and, if necessary, someone will call you back.
(b) repair and make operable your dual fuel equipment within forty-eight (48) hours of the equipment's failure; and
(c) provide the Company with documentation that your equipment has been repaired and you can immediately comply with the earlier of the ongoing interruption or a separate planned interruption.

All three conditions listed above must be satisfied for this exception to the two-violation rule to apply.

Please be advised that notification to the Company of a condition that prevents you from switching to your alternate energy source **does not excuse** you from payment of any unauthorized gas use charges or other applicable charges or surcharges or consequences, including termination of service.

- Please notify the Company immediately if there is a change in your contact person, telephone or fax number. You may email updated contact information to us at EM-GasInterruptions@coned.com, or fax it to us at 718-246-3239. Our notification system cannot accept telephone numbers that require an extension, a mechanical or oral response to connect the call.

A copy of the Company's gas tariff and Gas Sales and Transportation Operating Procedures ("GTOP") can be found on our web site at: http://www.coned.com - choose **Rates and Tariffs** at the bottom of the page – choose **Gas Rate and Tariff** and scroll down to view GTOP. To view our eLearning FAQ – click on "**How to Become a Gas Supply Company**" – scroll to the bottom of the page and click on "**FAQ**".

Holidays Observed During Heating Season
(November 1 – March 31)

January
- New Year's Day
- Martin Luther King Jr.'s Birthday

February
- President's Day

November
- Veteran's Day
- Thanksgiving Day
- Day after Thanksgiving

December
- Christmas

Gas Interruption Hotline
(212) 460-3459

For Interruptible Customers With Temperature Control

- Stop Using Gas
21 degrees F
- Resume Using Gas
26 degrees F

E-mail Requirement – You must provide the Company with an e-mail address for your account to help us expedite electronic communication.

Email Contact Information
EM-GasInterruptions@coned.com

See Affidavit on Next Page

Case 18-M-0272
Submission Date July 16, 2018
Version #:1

Please Complete and E-mail the Below Affidavit to Con Edison at EM-Affidavit@coned.com

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
CUSTOMER'S AFFIDAVIT FOR SERVICE CLASSIFICATION NOS. 9 AND 12

YOU MUST SUBMIT THIS AFFIDAVIT BY OCTOBER 1ST WITH ALL THE REQUIRED INFORMATION INCLUDING THE NAME AND EMAIL CONTACT INFORMATION FOR YOUR ALTERNATE FUEL SUPPLIER 9 (Number 6). IF YOU DO NOT RETURN THE AFFIDAVIT WITH THE REQUIRED INFORMATION YOU WILL NOT BE ELIGIBLE FOR THE INTERRUPTIBLE OR OFF-PEAK FIRM RATE UNDER SC 9 AND SC12

_______________ (hereafter "Customer"), by its officer, principal or partner or, for the Alternate Fuel/Energy Source Option only, by a person authorized to bind Customer, intends to receive or is receiving service from Consolidated Edison Company of New York, Inc. ("Con Edison" or the "Company") under Service Classification Nos. 9 or 12 (SC 9/SC 12) of its Schedule for Gas Service, P.S.C. No. 9 – GAS (the "Schedule") and submits the following affidavit to Con Edison:

STATE OF NEW YORK, CITY OF ________________________

Customer's Name: ____

Customer's Service Address: ____

Account Number: ____

Customer attests that:

(Please select one of the following two options, but note that availability of each option is subject to applicable eligibility requirements.)

ALTERNATE FUEL/ENERGY SOURCE OPTION

1. Customer's type of alternate fuel/alternate energy source is (check as appropriate):

Diesel: _____ Kerosene: _____ Propane: _____ No. 2 Fuel Oil: _____
No. 4 Fuel Oil: _____ No. 6 Fuel Oil: ___ Electricity: _____
Other: ____________________ (specify)

There is in place one or more executed contract(s) with one or more suppliers for diesel, kerosene, propane, No. 2 fuel oil, No. 4 fuel oil, and/or No. 6 fuel oil to provide for the delivery of such alternate fuel during the Winter Season (*i.e.*, November 1 – March 31) in quantities sufficient to meet Con Edison's reserve requirement in accordance with SC 9 and SC 12 and Con Edison's Gas Sales and Transportation Operating Procedures Manual ("GTOP"). Customer understands that the alternate fuel requirement is:

- Ten (10) days of supply for Interruptible or Off-Peak Firm Notification Customers based on Customer's peak Winter Season requirements. Such alternate fuel is available to Customer during the Winter Season on an as-needed basis.
- Seven (7) days of supply for existing Interruptible Temperature Control Customers based on Customer's peak Winter Season requirements. Such alternate fuel is available to Customer during the Winter Season on an as-needed basis.

2. (a) Customer has the following on-site storage facilities for its alternate fuel (insert "N/A" if not applicable):

Number of storage tanks on site: ____________

Total number of gallons of storage capacity: ___________

Total estimated peak days of storage: ________________.

(b) (Please check one): Customer ( ) is OR ( ) is not a "New Customer" (a "New Customer" for this purpose is one who commenced Interruptible or Off-Peak Firm service on or after 11/1/01).

New Customers must have a minimum of three (3) peak days of on-site storage.

3. Customer will maintain operable alternate fuel or alternate energy source equipment, as required by SC 9 and SC 12.

FEBRUARY 2017

4. Customer understands that it is subject to the penalties, charges and other consequences, including termination of service, as set forth in SC 9 or 12, as applicable, of the Company's Schedule, for failure to meet the Company's alternate fuel requirements and/or cease using gas as required.

5. I have read and understand all of Customer's obligations under SC 9 and SC 12, as applicable, including that Customer is responsible for replenishing its alternate fuel storage throughout the Winter Season as necessary to meet Customer's total fuel obligations whenever and so long as service is interrupted under SC 9 and SC 12, as applicable.

6. Customer understands that it is required to provide the name and email contact information for its Alternate Fuel Supplier and that if this information is not provided customer is in violation of the Company's Gas Tariff under SC 9 and SC 12 and will no longer be eligible for the Interruptible or Off-Peak Firm Rate.

Alternate Fuel Supplier Name: ______________________________

Alternate Fuel Supplier Email Address: ______________________________

OPERATIONAL SHUT-DOWN OPTION (an Officer, Principal or Partner must Sign)

1. Customer is a process load customer (as that term is defined in SC 9 and SC 12 and in the GTOP) whose operations Customer can timely shut down in response to a called interruption.

2. Customer is NOT a school or human needs customer (as the latter term is defined in SC 9 and SC 12) or an electric generator.

3. In accordance with the New York Public Service Commission's May 23, 2012 *Order Directing Certain Utilities to Submit Tariff Amendments* in Case 11-G-0543, Customer will, in lieu of the requirement to maintain a full alternate fuel supply during the Winter Season: (1) shut down its operations for the duration of any and all called interruptions; and (2) continue to comply with all other interruptible provisions described in Con Edison's Schedule.

4. Customer understands and acknowledges that it is subject to penalties, charges and other consequences as set forth in SC 9 or 12, as applicable, of the Company's Schedule for failing to shut down operations during a called interruption including but not limited to the Company taking steps, at Customer's expense, to physically terminate gas service to Customer's premises without prior notice in the event of Customer's failure to cease using gas as required.

Customer elects:

1.___________ Alternate Fuel/Energy Source Option

Or

2.___________ Operational Shut-Down Option (You must meet the eligibility requirements and an Officer, Principal or Partner Must Sign)

Customer's Name: ______________________________

By: Officer, Principal, Partner, or Authorized Person {Signature}:

____

Title: ______________________________

Date: ______________________________

Subscribed and sworn before me this ____day of _______, 20__

____

Notary Public

[Affix Notary's Stamp]

FEBRUARY 2017

Case 18-M-0272
Submission Date July 16, 2018
Version #:1

conEdison
a conEdison, inc. company

Consolidated Edison Company
of New York, Inc.
4 Irving Place
New York NY 10003
www.conEd.com

«CUST_NAME»
«MLAD_1»
«MLAD_2»
«MLAD_3»

September xx, 2017

Re: Customer Acct. #: «ACCT_NO»
Service Address: «SADD»
City and State: «TOWN» «ZIP»

Dear Interruptible or Off-Peak Firm Gas Customer:

The winter heating season is approaching quickly. This letter is to remind you that it is time to assess and make arrangements for your winter fuel supply requirements.

Your primary responsibility as a Con Edison interruptible or off-peak firm gas customer is to comply with and respond to any directive to interrupt your gas service initiated by Con Edison by switching to your alternate fuel in accordance with Service Classification Nos. 9 and/or No. 12 of the Company's Gas tariff which is available for viewing at www.coned.com.

Customer Affidavits (Mandatory): Attached you will find your Customer Affidavit which you are required to complete, sign and have notarized by close of business on **October 1, 2017**. **You must return this form with all the required information including the name and email contact information for your Alternate Fuel Supplier. If you do not return the affidavit with the required information you will not be eligible for the Interruptible or Off-Peak Firm Rate under SC9 and SC12.** Please e-mail the completed Affidavit form to EM-Affidavit@coned.com . **Please Note: the Shut-Down Option will only apply to customers who meet the criteria listed on the Affidavit under that section. Otherwise, please fill out the Alternate Fuel/Energy Source Option of the Affidavit.**

Customer Responsibility: You must have adequate reserves of your alternate fuel or alternate energy source available and have your dual fuel equipment and associated telephone lines in proper working order. In addition, you must replenish your fuel inventory during and after an interruption to the extent necessary, to operate your facilities satisfactorily, without gas whenever and so long as service is interrupted. **You must return your Customer Affidavit or you will not be eligible for the applicable rate as stated above.**

Customer Communications: Notification of an interruption will be via telephone, fax, e-mail and text message and will be issued with no less than eight (8) hours advance notice. You may not resume burning natural gas until you are notified (by automated telephone, fax, e-mail or text message) to do so by the Company.

E-Mail Requirement: You must provide the Company with an e-mail address for your account to help us expedite electronic communication.

Communications Test: The Company will conduct a test of its communication system at the end of October.

Planned Interruption: A planned interruption will be conducted by the Company in early November. Please be prepared for the planned interruption as failure to comply will result in the assessment of charges for unauthorized gas use and other applicable charges and/or consequences.

Unauthorized Gas Use Charges: the higher of (i) two times the sum of the market gas price as determined in accordance with the Company's Sales and Transportation Operating Procedures plus the applicable interruptible or off-peak firm transportation rate; or (ii) nine times the applicable interruptible or off-peak firm sales rate.

E-Learning (FAQ): Our eLearning FAQ is always available to assist you in understanding your responsibilities and will guide you through the notification process. You can access the eLearning FAQ by visiting our website at www.coned.com – choose the "**Become An Energy Service Company Partner"** towards the bottom of the page on the right side – then click on "**How To Become a Gas Supply Company"** – scroll to the bottom of the page and click on "**FAQ"** or you can use the direct link: https://www.coned.com/en/business-partners/how-to-become-a-gas-supply-partner/page-data/dual-fuel-faq. We are including in the letter a list of Operating Suggestions and Service Requirements for your use.

Page 2

Gas Interruption Hotline: During the winter months, our **Gas Interruption Hotline at 212-460-3459** is available to provide additional information on the status of interruptible gas service interruptions. You can also contact us at EM-GasInterruptions@coned.com.

As a valued Con Edison gas customer, please be assured that we very much want to help you minimize your fuel costs and that we are ready to assist you to make your interruptible gas service as convenient and economical as possible. At the same time, your full compliance with the Company's gas interruption procedures is necessary for the integrity of the Company's gas system and the reliability of the Company's service to customers without dual-fuel capability. If you have any questions about any of these matters, please contact me at 212-460-6920 or at camellom@coned.com.

Sincerely,

Michael Camello
Enclosures

conEdison

Con Edison Operating Suggestions and Service Requirements for Interruptible and Off-Peak Firm Gas Customers

- Ensure that your dual fuel equipment is in good working order and that a sufficient reserve of your alternate fuel or alternate energy source is always available.
- Designate a responsible individual to inspect your equipment every time an interruption of gas service is necessary to ensure the equipment is not operating on natural gas.
- Be prepared to switch to your alternate fuel or alternate energy source at any time upon notification from Con Edison, **even on holidays (see holidays observed by Con Edison on right)**.
- Admit Con Edison employees promptly to your premises for any necessary inspections of your gas usage equipment and controls.
- Notify Con Edison immediately of any emergency situation involving your gas service; or, if a condition develops that prevents you from switching to your alternate energy source. You can call the **GAS INTERRUPTION HOTLINE** at **(212) 460-3459** and leave a message. If necessary, someone will call you back. During the **off-hours** you can call **718-794-2900 / 2903 / 2904**. The **Gas Interruption Hotline** is activated for the entire heating season to provide you with information on interruptions and for you to leave a message, if necessary.
- **Two Violation Rule** – during the heating season, if you fail to fully interrupt your use of gas (except for any permitted use of gas for ignition purposes - maximum of 2 therms per hour) for two (2) interruption periods (including any planned interruption), the Company will notify you in a certified letter, return receipt requested that it will transfer you to the applicable firm service classification commencing with the billing month following the month in which the second violation occurs unless you choose to terminate your service at that time. ***Failure to interrupt your use of gas due to inoperable dual-fuel facilities counts as a violation towards the two-violation rule with one exception for each heating season.***
- Here is the criteria for the one equipment failure exception to the Two Violation Rule:

On one occasion during each heating season a customer's failure to interrupt the use of gas due to documented inoperable dual-fuel facilities will not be counted as a violation provided that you:

(a) notify the Company within one hour of the failure of your equipment. You can do this by calling the **GAS INTERRUPTION HOTLINE** at **(212) 460-3459**. You can leave a message and, if necessary, someone will call you back.
(b) repair and make operable your dual fuel equipment within forty-eight (48) hours of the equipment's failure; and
(c) provide the Company with documentation that your equipment has been repaired and you can immediately comply with the earlier of the ongoing interruption or a separate planned interruption.

All three conditions listed above must be satisfied for this exception to the two-violation rule to apply.

Please be advised that notification to the Company of a condition that prevents you from switching to your alternate energy source **does not excuse** you from payment of any unauthorized gas use charges or other applicable charges or surcharges or consequences, including termination of service.

- Please notify the Company immediately if there is a change in your contact person, telephone or fax number. You may email updated contact information to us at EM-GasInterruptions@coned.com, or fax it to us at 718-246-3239. Our notification system cannot accept telephone numbers that require an extension, a mechanical or oral response to connect the call. Please make sure your fax number is not on the "Do Not Call List" or the fax will not be delivered.

Holidays Observed During Heating Season
(November 1 – March 31)

January
- New Year's Day
- Martin Luther King Jr.'s Birthday

February
- President's Day

November
- Veteran's Day
- Thanksgiving Day
- Day after Thanksgiving

December
- Christmas

Gas Interruption Hotline
(212) 460-3459

For Interruptible Customers With Temperature Control

- Stop Using Gas
21 degrees F
- Resume Using Gas
26 degrees F

E-mail Requirement – You must provide the Company with an e-mail address for your account to help us expedite electronic communication.

Email Contact Information
EM-GasInterruptions@coned.com

A copy of the Company's gas tariff and Gas Sales and Transportation Operating Procedures ("GTOP") can be found on our web site at: http://www.coned.com - choose **Rates and Tariffs** at the bottom of the page – choose Gas Rates and Tariff and scroll down to view GTOP. To view our eLearning FAQ – click on How to Become a Gas Supply Company – scroll to the bottom of the page and click on "**FAQ**".

See Affidavit on Next Page

Please Complete and E-mail the Below Affidavit to Con Edison at EM-Affidavit@coned.com

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
CUSTOMER'S AFFIDAVIT FOR SERVICE CLASSIFICATION NOS. 9 AND 12

YOU MUST SUBMIT THIS AFFIDAVIT BY OCTOBER 1ST WITH ALL THE REQUIRED INFORMATION INCLUDING THE NAME AND EMAIL CONTACT INFORMATION FOR YOUR ALTERNATE FUEL SUPPLIER 9 (No. 6). IF YOU DO NOT RETURN THE AFFIDAVIT WITH THE REQUIRED INFORMATION YOU WILL NOT BE ELIGIBLE FOR THE INTERRUPTIBLE OR OFF-PEAK FIRM RATE UNDER SC 9 AND SC12

______________ (hereafter "Customer"), by its officer, principal or partner or, for the Alternate Fuel/Energy Source Option only, by a person authorized to bind Customer, intends to receive or is receiving service from Consolidated Edison Company of New York, Inc. ("Con Edison" or the "Company") under Service Classification Nos. 9 or 12 (SC 9/SC 12) of its Schedule for Gas Service, P.S.C. No. 9 – GAS (the "Schedule") and submits the following affidavit to Con Edison:

STATE OF NEW YORK, CITY OF ________________________

Customer's Name: ____

Customer's Service Address: ____

Account Number: ____

Customer attests that:

(Please select one of the following two options, but note that availability of each option is subject to applicable eligibility requirements.)

ALTERNATE FUEL/ENERGY SOURCE OPTION

1. Customer's type of alternate fuel/alternate energy source is (check as appropriate):

   Diesel: _____ Kerosene: _____ Propane: _____ No. 2 Fuel Oil: _____
   No. 4 Fuel Oil: _____ No. 6 Fuel Oil: ___ Electricity: _____
   Other: ____________________ (specify)

   There is in place one or more executed contract(s) with one or more suppliers for diesel, kerosene, propane, No. 2 fuel oil, No. 4 fuel oil, and/or No. 6 fuel oil to provide for the delivery of such alternate fuel during the Winter Season (*i.e.*, November 1 – March 31) in quantities sufficient to meet Con Edison's reserve requirement in accordance with SC 9 and SC 12 and Con Edison's Gas Sales and Transportation Operating Procedures Manual ("GTOP"). Customer understands that the alternate fuel requirement is:

   - Ten (10) days of supply for Interruptible or Off-Peak Firm Notification Customers based on Customer's peak Winter Season requirements. Such alternate fuel is available to Customer during the Winter Season on an as-needed basis.
   - Seven (7) days of supply for existing Interruptible Temperature Control Customers based on Customer's peak Winter Season requirements. Such alternate fuel is available to Customer during the Winter Season on an as-needed basis.

2. (a) Customer has the following on-site storage facilities for its alternate fuel (insert "N/A" if not applicable):

   Number of storage tanks on site: ______________

   Total number of gallons of storage capacity: ____________

   Total estimated peak days of storage: __________________.

   (b) (Please check one): Customer ( ) is OR ( ) is not a "New Customer" (a "New Customer" for this purpose is one who commenced Interruptible or Off-Peak Firm service on or after 11/1/01).

   New Customers must have a minimum of three (3) peak days of on-site storage.

3. Customer will maintain operable alternate fuel or alternate energy source equipment, as required by SC 9 and SC 12.

FEBRUARY 2017

4. Customer understands that it is subject to the penalties, charges and other consequences, including termination of service, as set forth in SC 9 or 12, as applicable, of the Company's Schedule, for failure to meet the Company's alternate fuel requirements and/or cease using gas as required.

5. I have read and understand all of Customer's obligations under SC 9 and SC 12, as applicable, including that Customer is responsible for replenishing its alternate fuel storage throughout the Winter Season as necessary to meet Customer's total fuel obligations whenever and so long as service is interrupted under SC 9 and SC 12, as applicable.

6. Customer understands that it is required to provide the name and email contact information for its Alternate Fuel Supplier and that if this information is not provided customer is in violation of the Company's Gas Tariff under SC 9 and SC 12 and will no longer be eligible for the Interruptible or Off-Peak Firm Rate.

Alternate Fuel Supplier Name: ______________________________

Alternate Fuel Supplier Email Address: ______________________________

<u>OPERATIONAL SHUT-DOWN OPTION (an Officer, Principal or Partner must Sign)</u>

1. Customer is a process load customer (as that term is defined in SC 9 and SC 12 and in the GTOP) whose operations Customer can timely shut down in response to a called interruption.

2. Customer is NOT a school or human needs customer (as the latter term is defined in SC 9 and SC 12) or an electric generator.

3. In accordance with the New York Public Service Commission's May 23, 2012 *Order Directing Certain Utilities to Submit Tariff Amendments* in Case 11-G-0543, Customer will, in lieu of the requirement to maintain a full alternate fuel supply during the Winter Season: (1) shut down its operations for the duration of any and all called interruptions; and (2) continue to comply with all other interruptible provisions described in Con Edison's Schedule.

4. Customer understands and acknowledges that it is subject to penalties, charges and other consequences as set forth in SC 9 or 12, as applicable, of the Company's Schedule for failing to shut down operations during a called interruption including but not limited to the Company taking steps, at Customer's expense, to physically terminate gas service to Customer's premises without prior notice in the event of Customer's failure to cease using gas as required.

Customer elects:

1.___________ Alternate Fuel/Energy Source Option

Or

2.___________ Operational Shut-Down Option (You must meet the eligibility requirements and an Officer, Principal or Partner Must Sign)

Customer's Name: ______________________________

By: Officer, Principal, Partner, or Authorized Person {Signature}:

____

Title: ______________________________

Date: ___________________________

Subscribed and sworn before me this ____day of _______, 20__

____

Notary Public

[Affix Notary's Stamp]

FEBRUARY 2017

Case 18-M-0272
Submission Date July 16, 2018
Version #:1

Fuel Replenishment Letter

conEdison

Consolidated Edison Company of New York, Inc.
111 Broadway, Suite 1601, New York, NY 10006

SAMPLE LETTER

MM/DD/YY

Re: Notice of Possible Need to Replenish Oil Inventories

Dear Customer:

In accordance with the Public Service Commission's November 4, 2003 Order concerning interruptible gas sales and transportation service, please be advised that because your accumulated gas service interruptions have exceeded a total of five (5) days prior to February 15th, you should now review your oil storage inventories in order to assess the potential need for replenishment. By promptly undertaking any necessary replenishment, you will be prepared in case Con Edison should find it necessary to require any additional interruptions this winter.

Please call our Gas Interruption Hotline at 212-460-3459, if you have any questions concerning this notice. Thank you for your cooperation.

Sincerely,

Frederick Archer

Orange & Rockland
a conEdison, inc. company

Orange and Rockland Utilities, Inc.
71 Dolson Avenue
Middletown NY 10940-6501
www.oru.com

Sample Letter Certified Package

September xx, 2017

Contact name
Company.
Address
City State zip

Acct: xxxx-xxxx

Re: Winter Interruptible Gas Season Notification

Dear Customer:

The "Gas Interruptible Season" is approaching quickly. This letter serves as a reminder that it is time to assess and make arrangements for your winter fuel supply requirements.

Your primary responsibility as an Orange and Rockland Utilities, Inc. (O&R) Interruptible Gas Customer is to comply and respond to any directive to interrupt your gas service initiated by O&R by switching to your alternate fuel in accordance with Service Classification No.8 (SC No. 8) of O&R's Gas Tariff. The Gas Tariff is attached for your convenience. You can also download and view the Gas Tariff at www.oru.com.

Customer Affidavits: Attached you will find a Customer Affidavit and a Customer Contact Sheet which you are required to complete and return to O&R by October 13, 2017. The Affidavit has been revised this year to include proposed Gas Tariff changes that are pending approval with the New York Public Service Commission (NYPSC).

Gas Tariff Changes: There have been changes to the interruptible gas tariff for the 2017-2018 season. If you have any questions about the tariff changes please contact your Major Accounts Engineer to discuss.

Customer Communications: Please be sure to include direct line telephone numbers where O&R can reach you or your designated responsible party, 24 hours a day, 7 days a week, inclusive of all holidays. Please keep in mind that telephone lines with voicemail, automated answering machines, and answering machines provided through cell network providers are **not direct lines** and may interfere with the clear and accurate delivery of the message. **O&R can now provide notification by text or email**. If you wish to receive notifications via text message or email please provide that information on the contact sheet. For each location you may submit up to three contacts and can utilize land telephone lines, cell phone numbers, text and emails to receive notifications.

Communications Test: O&R will schedule a communications test of the customer provided telephone numbers and e-mail addresses using our Gas Information Notification System (GINS) on or before November 3, 2017.

Scheduled Interruption: The Company will schedule a compliance interruption in November. Please be prepared for the scheduled interruption, as failure to comply will result in the assessment of applicable charges. As a reminder, please listen closely to the entire message notifying customers to switch to their alternate fuel for the requested time and duration of the interruption. Respond to the message by pressing the **"#"** key on your telephone key pad. Acknowledging receipt of the notice is part of O&R's interruption procedures.

Additionally, during any interruption the Gas Interruptible Transportation Hot Line will be available for use and updated with current interruption information. Attached you will find the telephone number and instructions for use.

Please Complete and Fax Below Affidavit to:

Orange and Rockland at or Mail it to:

ORANGE AND ROCKLAND UTILITIES, INC.

CUSTOMER'S AFFIDAVIT FOR SERVICE CLASSIFICATION NOS. 3, 8 & 9

__________________ ___ (hereafter ("Customer"), by its officer, principal or partner or, for the Alternate Fuel/Energy Source Option only, by a person authorized to bind Customer, intends to receive or is receiving service from Orange and Rockland Utilities, Inc. ("Orange and Rockland" or the "Company") under Service Classification Nos. 8 or 9 (SC 8 or SC 9) of its Schedule for Gas Service, P.S.C. No. 4 – GAS (the "Schedule") and submits the following affidavit to Orange and Rockland:

STATE OF NEW YORK, CITY/TOWN OF ....

Customer's Full Name: ______________________________

Customer's Service Address:____

Customer' Account Number: ………………………………

Customer attests that:

(Please select one of the following two options, but note that availability of each option is subject to applicable eligibility requirements.)

OPTION 1 - ALTERNATE FUEL/ENERGY SOURCE OPTION (FUEL STORAGE REQUIRED)

(i) Customer's type of alternate fuel/alternate energy source is (check as appropriate): Diesel: ____; Kerosene:____; Propane:____; No. 2 fuel oil:____; No. 4 fuel oil:____; No. 6 fuel oil______; Other: ________________(specify).

(ii) Customer has the following on-site storage facilities for its alternate fuel: Number of storage tanks on site: ______; Total number of gallons of storage capacity:___________; Total estimated peak days of storage:________________.

(iii) SC3, SC 8 and SC 9 Customer's on-site alternate fuel storage capacity will be filled as of November 1, and Customer will maintain operable alternate fuel equipment.

(iv) There is in place one or more executed contract(s) with one or more suppliers for diesel, kerosene, propane, No. 2 fuel oil, No. 4 fuel oil, and/or No. 6 fuel oil, as applicable, to provide for the delivery of such alternate fuel during the Winter Season (i.e., November 1 through March 31) in quantities equal to the difference between Customer's alternate fuel requirement (described below), and the amount of Customer's on-site alternate fuel. Alternate fuel deliveries under said contract(s) are available to the Customer during the Winter Season on an as-needed basis. (The alternate fuel requirement for SC 8 and SC 9 Customers is ten days of fuel reserves based on peak Winter Season requirements. The reserve requirement can be met through a combination of on-site storage and arrangements with alternate fuel providers to supply Customer with the additional amount required to meet the Customer's reserve requirement. Customers initiating service on or after December 1, 2001 are required to have at least 3 days of on-site storage of their alternate fuel.)

(v) Customer understands that it is subject to the penalties, charges and other consequences, including termination of service, as set forth in SC 8, and SC 9, as applicable, of the Schedule, for failure to meet the Company's alternate fuel requirements and/or cease using gas as required.

(vi) I have read and understand all of Customer's obligations under SC 8 and SC 9, as applicable, including that Customer is responsible for replenishing its alternate fuel storage throughout the Winter Season as necessary to meet the Customer's total fuel obligations, as applicable, whenever and so long as service under SC 8, and SC 9, as applicable, is interrupted.

OPTION 2 -OPERATIONAL SHUT-DOWN OPTION

(i) Customer is a process load customer (as that term is defined in SC 8) whose operations Customer can timely shut down in response to a called interruption.

(ii) Customer is NOT a school or human needs customer (as the latter term is defined in SC 8) or an electric generator.

Compliance Inspections: Over the next two months, an O&R Major Account Engineer may contact you to perform a random site inspection at your facility to ensure compliance with the alternate fuel requirements. Please note that all customers must have the required alternate fuel supplies **in place and available** on November 1, 2017.

Firm Base Load Requirements: Pursuant to the Company's Gas Tariff, all firm base load usage needs must be declared prior to November 1st. Please note the past few years we have experienced longer interruption periods which caused many FBL nominations to be push to the maximum limits. We recommend that you review your FBL requirements to ensure compliance and eliminate any chance of unauthorized use of gas during similar weather conditions. Please contact me before November 1st if you intend on electing a firm base load this year.

E-Learning Tool: An E-Learning tutorial "Interruptible Gas Customer Training" is available on O&R's website at www.oru.com/IGTutorial. The tutorial will assist you with the details of O&R's Interruptible Gas Program. The tutorial is to be used in conjunction with the Gas Tariff. We encourage you to review the E-Learning tool to refresh your understanding of your obligations under the Program. This tool can also be used as needed to train and refresh your staff with the Program.

Interruptions: The past few years weather conditions resulted in numerous and longer interruption periods over historical years. We strongly suggest that you verify that your equipment is operational and your alternate fuel is available in all-weather conditions. As noted in the tariff, the 2-strike conditions require automatic transfer to firm service for 1-year period.

Customer Meeting: O&R will be hosting a pre-season **Customer meeting** this year because there have been tariff changes.

If you have any further questions or concerns, please do not hesitate to contact me at 845-342-8949 or at galliganiiiv@oru.com. If you would like the documents electronically please email me.

Sincerely,

Vinny Galligan

Vincent Galligan III
Manager-
Natural Gas Programs & Initiatives

Attachments:
2017 Affidavit
2017 Contact update sheet
2017 Telephone Hot Line Directions
2017 Customer Expectations

Case 18-M-0272
Submission Date July 16, 2018
Version #:1

(iii) In accordance with the New York Public Service Commission's May 23, 2012 Order Directing Certain Utilities to Submit Tariff Amendments in Case 11-G-0543, Customer will, in lieu of the requirement to maintain a full alternate fuel supply during the Winter Season: (1) shut down its operations for the duration of any and all called interruptions; and (2) continue to comply with all other interruptible service provisions described in the Schedule.

(iv) Customer understands and acknowledges that it is subject to penalties, charges and other consequences as set forth in SC 8, as applicable, for failing to shut down operations during a called interruption, including but not limited to the Company taking steps, at Customer's expense, to physically terminate gas service to the Customer's premises without prior notice in the event of Customer's failure to cease using gas as required.

Customer elects

Option 1; with fuel storage Please Check ______

Option 2; shut down option Please Check ______

Customer' Name: ___________________________

By: Officer, Principal, Partner or Authorized Person {Signature}:___________________________________

Print name: _________________________________

Title: __________________________

Subscribed and sworn to before me this day of _______, 20__.

____
Notary Public

[Affix Notary's Stamp} _______________

Orange & Rockland
a conEdison, inc. company

Orange and Rockland Utilities, Inc.
71 Dolson Avenue
Middletown NY 10940-6501
www.oru.com

XX/XX/2017

Re: Notice of Possible Need to Replenish Oil Inventories

Dear Customer:

In accordance with the Public Service Commission's November 4, 2003 order concerning interruptible gas sales and transportation service, please be advised that because your accumulated gas service interruptions have exceeded a total of five (5) days prior to February 15th, you should now review your oil storage inventories in order to assess the potential need for replenishment. By promptly undertaking any necessary replenishment, you will be prepared in case Orange and Rockland should find it necessary to require any additional interruptions this winter.

Please call Vinny Galligan if you have any questions regarding this notice at 845-342-8949. Thank you for your cooperation.

Sincerely,

Vincent Galligan III
Manager- Natural Gas Programs & Initiatives

As discussed in the cover letter, the updates to your filings will be required within the first week of the months September through November. Each monthly update requires any changes to your filing questions and tables reports. We will be using the Table 8 from your October updates to provide the Commission with the latest available information at its **October 18th session,** so please be timely with your updates. Thank you again for your continued assistance with this statewide effort.

Exhibit __ (GL-7):

Con Edison Response to EDF-2-1; Case No. 17-G-0606

Company Name: Con Edison
Case Description: Con Edison Smart Solutions for NGC Customers
Case: 17-G-0606

Response to EDF Interrogatories – Set EDF-2
Date of Response: April 15, 2019
Responding Witness: May Cheng

Question No. : 1

Please refer to Con Edison's response to EDF Informational Request 1-2, subpart c, which states that "when available, the Company has entered into service agreements with pipelines for pipeline capacity that has been turned back and not renewed by other existing capacity holders." Please provide a list of all service agreements Con Edison has entered into with pipelines for pipeline capacity that has been turned back. For each service agreement, please specify the pipeline, contract number, maximum daily transportation quantity (by season if different), upstream receipt MDQ by receipt point and name, Con-Edison/O&R City-Gate point MDQ and name(s), the start date and the expiration date.

RESPONSE:

Please see below for contracts that Con Edison has entered into for pipeline capacity that was either turned back or not renewed by other existing capacity holders, or made available from the pipeline operator resulting from effects of incremental projects or system changes leading to available capacity:

Pipeline Company	**Contract Number**	**Receipt MDQ Volume (Dt/d)**	**Receipt Point**	**Delivery MDQ Volume (Dt/d)**	**Delivery Point**	**Start Date**	**End Date**
Iroquois	560-18	20,000	Brookfield	20,000	Hunts Point	11/1/2017	10/31/2020
Tennessee	323455	25,625	Shelton	25,625	Rye	4/1/2017	3/31/2022
Tennessee	323455 (amended)	30,625	Shelton	30,625	30,625 through 10/31/2020, then 25,625 starting 11/1/2020 (Rye) 5,000 starting 11/1/2020(White Plains)	11/1/2018	10/31/2023
Texas Eastern	911639	14,000	Mahwah and	14,000	Lower Manhattan	4/1/2019	10/31/2033

			Ramapo				
Texas Eastern	911640	3,500	Mahwah and Ramapo	3,500	Lower Manhattan	4/1/2019	10/31/2033

Exhibit __ (GL-8):

Rhode Island Joint Memorandum; Docket 4816

nationalgrid

Celia B. O'Brien
Assistant General Counsel and Director

February 20, 2019

VIA HAND DELIVERY AND ELECTRONIC MAIL

Luly E. Massaro, Commission Clerk
Rhode Island Public Utilities Commission
89 Jefferson Boulevard
Warwick, RI 02888

RE: Docket 4816 - Gas Long-Range Resource and Requirements Plan for the Forecast Period 2017/18 to 2026/27
Joint Memorandum

Dear Ms. Massaro:

On behalf of National Grid[1] and the Division of Public Utilities and Carriers (Division), I enclose for filing with the Public Utilities Commission (PUC) in the above-referenced docket ten (10) copies of the Company's and the Division's Joint Memorandum outlining the parties' joint recommendations for improving the Gas Long-Range Resource and Requirements Plan as it relates to the annual Gas Cost Recovery proceeding. This filing is made in compliance with the PUC's October 30, 2018 Open Meeting decision in Docket No. 4872.

Thank you for your attention to this filing. If you have any questions concerning this transmittal, please contact me at 781-907-2153 or Rob Humm at 401-784-7415.

Very truly yours,

Celia B. O'Brien

Celia B. O'Brien

Enclosures

cc: Docket 4816 Service List
Kevin Lynch, Division
Jonathan Schrag, Division
Tom Kogut, Division
John Bell, Division
Leo Wold, Esq.

[1] The Narragansett Electric Company d/b/a National Grid (National Grid or the Company).

280 Melrose Street, Providence, RI 02907
T: 781-907-2153 ■ celia.obrien@nationalgrid.com ■ www.nationalgrid.com

Certificate of Service

I hereby certify that a copy of the cover letter and any materials accompanying this certificate was electronically transmitted to the individuals listed below.

The paper copies of this filing are being hand delivered to the Rhode Island Public Utilities Commission and to the Rhode Island Division of Public Utilities and Carriers.

Joanne M. Scanlon

February 20, 2019
Date

Docket No. 4816 – National Grid's Gas Long-Range Resource Plan
Service List as of 2/5/2019

Name/Address	E-mail	Phone
Robert Humm, Esq. National Grid 280 Melrose St. Providence, RI 02907	Robert.humm@nationalgrid.com; Celia.obrien@nationalgrid.com; Joanne.scanlon@nationalgrid.com;	401-784-7415
Elizabeth D. Arangio Theodore Poe Nancy Culliford National Grid 40 Sylvan Road Waltham, MA 02541	Theodore.poe@nationalgrid.com; Elizabeth.Arangio@nationalgrid.com; Nancy.culliford@nationalgrid.com;	
Leo Wold, Esq. Division of Public Utilities & Carriers	Leo.Wold@dpuc.ri.gov; John.bell@dpuc.ri.gov; Jonathan.schrag@dpuc.ri.gov; Ronald.Gerwatowski@dpuc.ri.gov; dmacrae@riag.ri.gov; Al.mancini@dpuc.ri.gov; MFolcarelli@riag.ri.gov ;	401-780-2177
Greg Lander, President Skipping Stone, LLC 83 Pine St., Suite 101 West Peabody, MA 01960	GLander@skippingstone.com;	978-717-6140
File an original & nine (9) copies w/: Luly E. Massaro, Commission Clerk Margaret Hogan, Commission Counsel	Luly.massaro@puc.ri.gov; Alan.nault@puc.ri.gov; Patricia.lucarelli@puc.ri.gov;	401-780-2107

Public Utilities Commission 89 Jefferson Blvd. Warwick RI 02888	Margaret.hogan@puc.ri.gov; Sharon.ColbyCamara@puc.ri.gov; Todd.bianco@puc.ri.gov;	
Office of Energy Resources Christopher Kearns Nicholas Ucci	Christopher.Kearns@energy.ri.gov; Nicholas.ucci@energy.ri.gov;	

JOINT MEMORANDUM OF
THE NARRAGANSETT ELECTRIC COMPANY d/b/a NATIONAL GRID
AND THE DIVISION OF PUBLIC UTILITIES AND CARRIERS

Introduction

On October 30, 2018 in The Narragansett Electric Company d/b/a National Grid's (National Grid or the Company) 2018 Gas Cost Recovery (GCR) proceeding, Docket No. 4872, the Public Utilities Commission (PUC) ordered that National Grid and the Division of Public Utilities and Carriers (Division) (collectively, the Parties and, individually, a Party) submit a joint memorandum in Docket No. 4816 outlining each of their recommendations for improving the Long Range Gas Supply Plan (LRP) as it relates to the annual GCR filing. The Parties submit this Joint Memorandum in compliance with the PUC's October 30, 2018 ruling in Docket No. 4872.

In addition to the outline of joint recommendations below, the Parties also believe it is helpful to provide a "problem statement" and summarize the underlying causes of the problem.

Problem Statement

How can the current regulatory review processes be revised to:

(i) provide the Company assurance that it has the support of its regulators before it makes substantial financial commitments that place the Company at prudency risk from after-the-fact regulatory challenges; and

(ii) provide regulators assurance that an unreasonable financial risk is not being placed on customers to bear the financial responsibility for long-term commitments that may turn out to be too conservative or unnecessary, when other reasonable alternatives at lower cost may have been available?

Two competing interests drive the problem statement. On the one hand, the Company seeks to obtain the Division's support for commitment decisions in advance of the commitments being made. It is completely understandable to the Division why regulatory support is important, when the net present value of the commitments involve tens of millions of dollars and could put the Company at prudency risk if the Division later disagrees with the commitment decision after it is too late for the Company to shift course. On the other hand, the Division desires to have insight into the rationale and justification for these commitments, to assure that customers are not being over-committed, and stranded contract costs are not being created for the future. But the current processes do not provide enough time for the Division to adequately review the decisions in advance and the Division has not been comfortable with the level of detail provided by the Company to support the decisions in advance.

Causes of the Problem

The markets in New England have changed significantly because of capacity issues that impact the reliability and cost of gas supply. This is a very different market than what was in existence over the past two decades. In the past, the key procurement decisions have revolved around gas supply purchases that rarely gave rise to pipeline constraint issues. As a result, the types of decisions that needed to be made by the Company annually tended to relate to supply contracts and the question of whether the Company should be making short- or medium-term supply commitments, given the prevailing market conditions at the time.

However, the rising demand for natural gas has resulted in winter capacity constraints that have changed the Company's procurement decisions. As can be seen from the recent GCR dockets, as well as the Company's efforts to find a longer-term solution to substitute for the loss of the liquefied natural gas (LNG) tank in Cumberland, the Company has been faced with procurement decisions that contemplate long-term contractual commitments that will result in significant costs to customers.

In the past, the LRP filings were not controversial and tended to raise few complicated issues. But now, the Company needs to plan in a way that assures adequate capacity and delivery security under supply contracts, the magnitude and implications of which have grown substantially. As a result, the current framework and template for the Company's long-range planning is no longer sufficient for an appropriate regulatory review. Further, the short time allowed for review in the GCR docket is not conducive to a complete and reasonable review. Left in its current state of regulatory processes, the GCR could become an annual contentious process with the Division compelled to oppose Company cost-recovery on the grounds that the Company has not adequately supported its decisions. Such an annual contentious process is not in the best interest of customers or the Company.

Additionally, there are two more specific items directly affecting the Company that stem from the regional capacity constraints. First, the Company's Capacity Exempt Transportation-only customers who rely on gas suppliers to deliver firm gas supply on interstate pipeline capacity that is held by third parties now assume more risk because their gas suppliers do not have access to interstate pipeline capacity due to regional constraints. Third-party suppliers are typically unwilling to make long-term (20-year) commitments to interstate pipeline companies that are necessary to build new pipeline projects. Second, due to on-system limitations, gas growth on the Company's system has resulted in the need to deliver gas to specific take stations fed by either Tennessee Pipeline Company or Algonquin Gas Transmission. This poses challenges that need to be addressed, such as limitations for gas supply options to meet gas growth.

Outline of Potential Solution

The Parties provide the following outline to address the LRP requirements and review and the annual GCR docket:

(1) The LRP filing should take place after the winter period, using the same forecasts that will be used for the GCR docket in that year;

(2) The LRP should no longer be limited to a foundation for planning that shows how the Company plans, but should also include concrete information about how the Company is planning to address supply and capacity needs over the five-year period;

(3) The LRP should be subject to approval by the PUC;

(4) If there is a material change to the LRP after approval, the Company should be required to make a supplemental filing with the PUC with notice to the Division;

(5) A new requirement should be established through which the Company is required to seek advance approval through a filing and proceeding at the PUC for long-term commitments that meet certain triggering criteria relating to the net present value of the cost and term of commitment; and

(6) To the extent that the larger-impact commitments are addressed through the new pre-approval process and the official approval of the LRP, this should reduce the number of litigated issues that occur in the GCR. In other words, the GCR should become a proceeding that effectively reconciles costs from known and supported commitments, rather than first-impression review of decisions that create an "all-or-nothing" financial risk for either the Company or customers.

Specific elements of this proposed solution are described in more detail below.

Long-Term Commitments:

The Parties strongly believe that item No. 5 above is a critical step in providing resolution to the long-term planning issue. The Parties believe that adoption of a "Review and Approval" mechanism in connection with long-term gas supply and/or gas transportation commitments would be beneficial. Such a mechanism would:

- Allow the Company to provide the PUC and Division with a detailed description of the proposed transaction, what gives rise to the propose transaction, what alternatives have or have not been studied and why, prior to commitment;

- Provide for formal discovery so that the PUC and Division have an opportunity to fully understand the proposed transaction;

- Provide for approval by the PUC and consent from the Division (to the extent deemed to be prudent and in the best interests of the Company's customers); and

- Upon receipt of such approval, provide the Company with assurance of recovery of the proposed costs and price structure associated with such transaction.

In furtherance of the development of such a mechanism, the Parties propose the following process:

Criteria Applicable to Commitments Greater than One Year in Duration – The Parties propose that the Review and Approval mechanism would be applicable to any gas supply and/or gas transportation commitment that will have a duration in excess of one year.

Filing – Prior to committing to any such transaction, the Company shall submit a filing to the PUC, seeking approval, and to the Division, seeking consent, to any such transaction. Such filing shall include (1) a detailed description of such transaction (including term and estimated cost); (2) a description of the customer need that such transaction is intended to address; (3) a description of the range of viable alternatives that could address the customer need; (4) a description of the alternative transactions that the Company evaluated with the results of the evaluations; and (5) such other information as may be useful to the PUC and Division in connection with their evaluation of the proposed transaction.

Discovery – Following submission of the filing, the Company shall respond to discovery requests from the PUC and Division.

Timing – The Company shall make its filing at least six months prior to the date by which it seeks approval of any transaction. Discovery shall occur, at the discretion of the PUC and Division, any time following the date of such filing until the date that is one month prior to the requested approval date. The Company shall provide written responses to the discovery requests on a rolling basis as soon as possible, and no later than 14 business days of receipt of any such request. The Division shall decide on the Company's request for consent by the requested date. The PUC shall rule on the Company's request for approval by the requested date.

Short-Term Commitments:

Notification of Short Term Commitments – Any gas supply or gas transportation commitments that have a duration of one year or less and have a reservation charge or demand charge that is $1 million or greater will be submitted to the Division, accompanied by a brief description of the context for the commitment, within 15 business days of the commitment being made, to give the Division time to commence its review prior to the annual GCR filing.

Comprehensive LRP:

The Company's bi-annual LRP filing submitted in March 2018 (Docket No. 4816) needs to be fully reviewed and approved to be able to move forward with certainty on long-term planning. For example, design planning standards and related forecasting are fundamental drivers to long-term planning, and they can potentially lead to significant cost decisions. The Company and the Division will meet to review its design planning and related forecasting methodologies. If these can be approved in a timely manner, such standards and related forecasts will be used in the Company's 2019 LRP and GCR submissions. Otherwise, the Company will use its current standards and related forecasting methods in its 2019 LRP and GCR submissions while the Company and Division continue their discussions, and any modifications or updates will appear in the Company's LRP and GCR submissions in 2020 and beyond, subject to each Party's right to take whatever position it deems appropriate in any related PUC proceedings if agreement cannot be reached.

Another item that needs to be reviewed is the impact to the portfolio from the Company's largest customers (FT-1), including those that the Company partially plans for as well those that the Company does not plan for (capacity exempt customers). These important items need to be fully vetted so that both the Company and the Division are comfortable using them in the forecasting and planning process going forward.

Once the forecasting and planning process is fully reviewed and vetted, the Company will be able to incorporate the agreed-upon results into the future annual process described below, resulting in a comprehensive LRP (Comprehensive LRP).

Subsequent Annual LRP Filings:

Once the Comprehensive LRP is fully vetted and approved, the Company will incorporate all elements of the Comprehensive LRP into subsequent annual LRP filings, which will be scaled-down versions of the Comprehensive LRP, but will include concrete information about how the Company is planning to address supply and capacity needs for the upcoming winter season as well as what the Company is pursuing for the remaining four-year period.

The annual LRP filings would be submitted in June, as soon as practical, following the release of the Company's annual forecast, permitting the Company to base its annual forecast on the most recent customer usage data and prior to the Company's annual GCR filing. These annual LRP filings will include such information as:

- Retail volume forecast by rate group for normal weather;
- Retail meter count forecast by rate group for normal weather;
- Rhode Island Economic Forecast variables for normal weather;
- Wholesale volume forecast by rate group for normal and design weather;
- SENDOUT® forecasts (normal and design weather) for capacity planning purposes for volumes and costs;
- Updated portfolio information showing all changes to the portfolio (capacity/supply/LNG), including:
    - Updated Chart IV-C-2 (schematic) if any changes have occurred;
    - Updated Chart IV-C-3 (a description of the contracts within the portfolio, including expiration date and evergreen provisions);
    - A consolidated version of Sections IV.C. (Available Resources), IV.C.2. (Underground Storage Services), and IV.C.3. (Peaking Resources); and
    - A consolidated version of Section IV.C.3.b. (e.g., LNG and/or CNG Contracts);
- Detailed information on needs for upcoming winter season, including SENDOUT® analysis showing derivation of need;
- Discussion of subsequent four-years and associated need and what the Company is pursuing with potential suppliers and pipelines to meet customer requirements, as well as expected costs of options;
- Provide historic (5-10 years) and projected (out 5 years) annual wholesale load duration curves showing the following:
- Stack existing supply resources (by path) against the daily wholesale load duration curve for historic period;
    - Stack proposed supply resources (by path) against the daily wholesale load duration curves for the projected periods;
    - Stack existing supply resources (by path) against the daily wholesale load duration curves for the historic November-March period;
    - Stack proposed supply resources (by path) against the wholesale load duration curves for the projected November-March periods; and
    - The Company will endeavor to develop equivalent hourly wholesale load duration curves;

- For individually metered high load factor Transportation customers, the Company will develop aggregated annual historic (5-10 years) and projected (out 5 years) load duration curves. For those customers with hourly metering, the Company will endeavor to provide the historic (5 years) aggregated hourly load duration curve;

- The Company will provide fixed cost of existing supply resources on a dollar per dekatherm (Dth) per day basis (annualized). Once individualized, then the Company will provide the same annualized information by path;

- For each existing supply resource (by path), the Company will provide an estimated effective Fixed Cost (on a Dth per day basis) (i.e., taking into account load factor utilization) for the current period and forecasted time periods for both its normal and design weather scenario, which is the basis of the Company's decision-making;

- For each proposed supply resource (by path), the Company will provide an estimated effective Fixed Cost (on a Dth per day basis) (i.e., taking into account load factor utilization) for the current period and forecasted time periods both for its normal and design weather scenario, which is the basis of the Company's decision-making; and

- For the gas commodity for each of the next five years of projected periods (annual and November through March), the Company will provide, by month for each projected period, the dollar per Dth for the gas estimated to be used on each path under both normal and design weather. The Company will also present the effective citygate gas (variable) cost by month of each path accounting for usage rates and fuel under both normal and design weather.

Subsequent to the annual LRP submission, the Company and the Division will jointly review the LRP submission, and the Company will keep the Division abreast of its plans for the portfolio for the upcoming GCR year.

With a firm basis founded in the review of the Comprehensive LRP filing, the Parties believe that these annual LRP filings would satisfy the statutory requirement of biannual submissions and will provide the Division with sufficient time to review the GCR filing without the need to seek additional time past the GCR hearing to investigate gas costs.

GCR Filing:

The annual GCR filing will reflect the final costs and volumes that are derived from the annual LRP filings. The Company will prepare a comparison of volumes and costs presented in its GCR filing in the same form (i.e., presentation format) as its annual LRP filing from June of the same year and identify any differences. By the time the GCR is filed, these items found in the Company's LRP submission will have already been fully vetted, and the Division will only need to review any changes that have occurred in the interim or are projected by Company to occur during the upcoming GCR period, subject to the Division's right to review and dispute any costs in the GCR that were not approved in accordance with the process identified in this Joint Memorandum or otherwise.