STATE OF NEW HAMPSHIRE
BEFORE THE
PUBLIC UTILITIES COMMISSION

In the matter of

Liberty Utilities (EnergyNorth Natural Gas) Corp.

Docket No. DG 17-198

Petition for Approval of Natural Gas Supply Strategy

DIRECT TESTIMONY

OF

Dr. Pradip K. Chattopadhyay
Assistant Consumer Advocate

September 13, 2019

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## I. Introduction

**Q. Please state your name, business address and occupation.**

A. My name is Pradip K. Chattopadhyay. My business address is 21 South Fruit Street, Suite 18, Concord, New Hampshire. I am employed as the Assistant Consumer Advocate/Rate and Market Policy Director with the New Hampshire Office of the Consumer Advocate (OCA).

**Q. Please describe your formal education and professional experience.**

A. I have a Ph.D. in Economics from the University of Washington, Seattle, which I earned in 1997. I have also taken courses in City and Regional Planning with applications to Energy Planning from Ohio State University, Columbus OH, in 2001-02. I have taught several courses in economics at the University of Washington as an instructor and adjunct faculty at its Business School. I am also associated with the Southern New Hampshire University (SNHU) as an adjunct faculty, where I teach courses in economics.

From March 1998 to October 1999, I was a Consultant with the National Council of Applied Economic Research, New Delhi, India. From November 1999 to August 2001, I was the Economist at the Uttar Pradesh Electricity Regulatory Commission (UPERC) in India, and advised UPERC on tariff issues. From September 2001 to June 2002, I worked at the National Regulatory Research Institute, Columbus, Ohio, as a graduate research associate while pursuing advanced courses in Energy Planning in the City and Regional Planning Program at Ohio State University. From June 2002 to July 2002, I worked at the World Bank, Washington D.C. as a short-term consultant/intern with its Energy and Water Division.

I worked at the New Hampshire Public Utilities Commission (Commission) from August 2002 to January 2007 in the capacity of a Utility Analyst. My responsibilities at the Commission as an analyst were in electric utility issues including analyzing and advising the Commission on rate design, cost of capital issues, wholesale market issues, and other regional matters. I briefly worked at the Massachusetts Department of Telecommunications and Energy (later reorganized into Department of Public Utilities (MA-DPU)) starting in January 2007 as an Economist. At MA-DPU, I represented the staff and examined gas demand estimation and forecasting, decoupling issues, and environmental remediation matters.

I returned to the Commission in June 2007 to join its Telecom Division as its Assistant Director, and continued in that position until December 2010. I was also helping other divisions as an expert witness in economics-related issues as well as advising the Commission on regional electric matters including FERC jurisdictional issues. I joined the Commission's Regional Energy Division in January 2010 as the Regional Energy Analyst, and was advising the Commission in that capacity until I joined the Antitrust and Utilities Division, Office of the Minnesota Attorney General, in August 2013.

I returned to New Hampshire in March 2014 and worked as an independent consultant until the end of August, 2014, representing the Minnesota Attorney General. I joined Liberty Utilities in August, 2014 as a Forecasting Analyst for its Energy Procurement Department. I worked with Liberty Utilities for about three months. In December 2014, I joined the OCA as its Rate and Market Policy Director. I was later appointed as the Assistant Consumer Advocate at the OCA.

**Q. Have you previously provided testimony before this Commission?**

A. Yes.

**Q. In which dockets did you testify?**

A. I provided testimony before the Commission in the following dockets:

- DE 03-200 – Rate design testimony which was about delivery rates for retail ratepayers of Public Service of New Hampshire (PSNH);
- DE 06-028 – Cost of capital testimony which was also about PSNH's delivery rates;
- DT 07-027 – Status of competition in retail telephony under TDS;
- DG 08-009 – Cost of equity testimony related to gas delivery rates of National Grid NH;
- DE 09-035 – Cost of equity testimony in the matter of electric distribution rates (PSNH);

- DG 14-380 – Petition of Liberty Utilities (EnergyNorth Natural Gas) requesting approval of firm transportation contract (North East Direct (NED));
- DG 15-155 – Petition of Valley Green, LLC requesting franchise in City of Lebanon and Town of Hanover, New Hampshire;
- DG 15-289 – Petition of Liberty Utilities (EnergyNorth Natural Gas) requesting franchise in City of Lebanon and Town of Hanover, New Hampshire;
- DG 15-494 – Petition of Liberty Utilities (EnergyNorth Natural Gas) requesting approval of firm transportation contract (NED);
- DE 16-383 – Petition of Liberty Utilities (Granite State Electric) for Permanent Rate Increase;
- DE 16-384 – Petition of Unitil for Permanent Rate Increase;
- DG 16-852 – EnergyNorth's Petition for Lebanon-Hanover Franchise Approval;
- DG 17-048 – EnergyNorth's Gas Distribution Service Rate Case;
- DG 17-070 – Northern Utilities' Gas Distribution Service Rate Case;
- DW 18-165 – Abenaki-Rosebrook Rate Case; Oral Testimony on Return on Equity
- DW 18 – HAWC Rate Case; Oral Testimony on Return on Equity

- DG 18-140 Liberty Utilities Petition for Approval of RNG Supply and Transportation Contract.

**Q. Have you ever provided testimony and affidavits before other Commissions?**

A. Yes. I have testified on cost of capital before the Minnesota Public Utilities Commission in dockets G008/GR-13-316 and GR 13-617. I have also provided an affidavit before the Federal Energy Regulatory Commission in a FERC Docket ER 09-14-000 on NSTAR's petition for ROE incentive adders on behalf of the New England Conference of Public Utilities Commissioners (NECPUC).

**Q. What is the purpose of your testimony?**

A. The purpose of my testimony is to analyze EnergyNorth's petition for approval of its Gas Supply Strategy, involving proposed contractual agreements and infrastructure development projects, and provide my recommendations for the Commission's consideration. As the OCA statutorily represents the interest of residential ratepayers at large, our primary focus in this docket is to determine whether the strategy proposed by the Company reasonably serves the interest of residential ratepayers. As the Company's petition is crucially informed by its SENDOUT[1] analyses, what follows is an examination of the inputs into the Company's SENDOUT

[1] SENDOUT, which is a gas-supply planning software platform, contains two modules, i.e. an Optimization Module and an Asset Valuation Module. EnergyNorth relied on the Optimization Module to conduct its analysis. The Optimization Module models fixed and variable costs associated with resources to determine the most cost-effective resource portfolio in meeting a gas utility's load requirements over a period of time.

analyses, further examination of the Company's findings, as well as additional analysis, with the focus being the economics of the Company's proposed strategy from ratepayers' perspective. Because I conclude that the Company's strategy, as proposed, is not reasonable, I also recommend changes to the Company's proposed strategy, so that its supply strategy going forward properly addresses ratepayers' concerns. This focus specifically informs our recommendations on the specific contractual arrangements and the infrastructure development projects that are subject of this docket.

**Q. Please discuss how your testimony is organized.**

A. As for what follows, Section II briefly provides a summary of the Company's analysis in support of its preferred supply strategy. I summarize the Company's analysis in its original filing, and its analysis per its supplemental testimony filed later, in March 2019.[2]

Section III provides OCA's critique of the Company's analysis by focusing individually on specific modeling inputs, arranged in subsections. Section IV relies on the Company's responses to stakeholders' data requests (DRs) as well as key changes to the

[2] The supplemental testimony accommodates a Customer Benefit Guarantee (informed by the Company's signing of a Memorandum of Understanding (MOU) with Calpine to provide natural gas supply to Granite Ridge Energy Center (GREC), a 745-megawatt gas-fired electric generation facility located in Londonderry, New Hampshire), another modest adjustment to the demand forecast, and updated cost estimates on both the pipeline and the liquefied natural gas (LNG) projects.

modeling assumptions, and provides the OCA's findings on what may constitute a just and reasonable supply strategy for EnergyNorth going forward.

Section V concludes with an analysis of bill impacts and the OCA's recommendations. Section VI includes the schedules that inform the OCA's analysis. Finally, Section VII provides Attachments 1-8.

## II. Summary of the Company's Petition

**Q. Please provide a brief summary of the Company's initial petition.**

A. EnergyNorth's initial petition primarily seeks approval of:

(i) a delivered supply contract with ENGIE Gas & LNG LLC ("ENGIE");[3]

(ii) a precedent agreement with Portland Natural Gas Transmission System ("PNGTS") for firm transportation capacity;[4] and

(iii) a new project (Granite Bridge Project) consisting of the construction of an in-state transmission pipeline (Granite Bridge Pipeline) and an on-system liquefied natural gas ("LNG") facility (Granite Bridge LNG Facility).

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[3] 90-day winter, combination (i.e., liquid and/or vapor) service with a maximum daily quantity ("MDQ") of 7,000 Dth per day and total annual contract quantity ("ACQ") of 630,000 Dth for the winters of 2018/19 through 2021/22.

[4] 5,000 Dth per day of firm transportation capacity from the Dawn Hub on the Union Gas Limited ("Union Gas"), TransCanada PipeLines Limited ("TCPL") Canadian Mainline, and PNGTS pipeline systems to the hub in Dracut, Massachusetts.

With respect to determining the supply strategy, the Company employed a software platform known as SENDOUT, commonly used in the gas industry for short- and long-term supply portfolio optimization.[5] The Company relied on its forecast of 20 years of design-day demand, i.e., the demand it would be required to meet on the coldest day of the winter during each of those 20 years. Employing these projections, the Company performed SENDOUT runs to justify its near-term requirements as well as long-term needs that EnergyNorth deems to be consistent with the "best-cost" resource planning standard used in the Least Cost Integrated Resource Plan currently pending with the Commission in Docket No. DG 17-152.[6] Broadly, the key aspects of the Company's analysis includes its approach to forecasting annual design-day requirements,[7] the use of a twenty-years' planning horizon (split years 2017-18 to 2037-38; 2018-19 to 2038-39 in the supplemental testimony), the use of levelized costs for Granite Bridge Project to reflect cost-incidence on ratepayers, examination of alternative supply scenarios with or without existing propane facilities,[8] modeling the future daily basis (i.e., the price differential) between Dracut and Henry Hub for winter using a Monte Carlo simulation

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[5] *See* note 1, *supra.*

[6] EnergyNorth's 2017 Lead Cost Integrated Resource Plan, at page 11, describes a "best-cost" portfolio as one where "resource decisions appropriately balance cost considerations with those related to supply security, contract flexibility, and supply viability."

[7] Design Day represents Local Distribution Company's peak demand day, which usually occurs during extreme cold weather conditions. The design day requirement anticipates the demand on the highest flow days so that the LDC can design its natural gas distribution system and operations to meet its customers' needs.

[8] *See* Direct Testimony of Willliam R. Killeen and James M. Stephens, Bates page 184R, for a listing of the supply options that EnergyNorth modeled in its SENDOUT scenarios.

relying on historical data for 2011 to 2018, and examination of incremental Concord Lateral[9] 75,000 Dth per day capacity (transportation) as a sole alternative to the Granite Bridge Pipeline (with a capacity of 150,000 Dth per day).

Methodologically, EnergyNorth first conducted a comparison of the projected costs for its preferred Granite Bridge Pipeline (GBP) project with a 75,000 Dth per day potential contract with Tennessee Gas Pipeline (TGP) for Concord Lateral expansion. The analysis was couched in terms of a GBP's yearly levelized cost versus the yearly cost associated with Concord Lateral's incremental capacity. Based on that analysis, the Company concluded that GBP was unquestionably more cost-effective than pursuing a contract with TGP for incremental Concord Lateral capacity. Given that finding, the Company then proceeded, using SENDOUT, to look at different scenarios with alternative resource portfolios that all assumed existence of the Granite Bridge Pipeline (as proposed).

**Q. Please list all scenarios that EnergyNorth analyzed in its Direct Testimony using SENDOUT.**

A. The Company examined six scenarios assuming that Granite Bridge Pipeline begins operation in 2020-21. These scenarios are succinctly captured in the Direct

[9] The Concord Lateral is the transmission pipeline, owned by Tennessee Gas Pipeline (TGP) that runs from the Dracut Hub, roughly paralleling the Interstate 93 corridor, north to Concord. It is presently the sole pathway through which natural gas reaches the EnergyNorth distribution system directly from the interstate national gas transmission system.

Testimony of William R. Killeen and James M. Stephens, Bates pages 193 and 202, in Tables 9 and 10. These scenarios were labelled Resource Planning Scenarios WRK/JMS-4, WRK/JMS-5, WRK/JMS-6, WRK/JMS-7, WRK/JMS-8, and WRK/JMS-9, respectively. Essentially, EnergyNorth modeled two sets of scenarios. The first set assumed that the Granite Bridge LNG storage facility ("LNG facility") was in place starting 2021-22, while the other set assumed that the LNG facility is not built. Also, the Company examined how the presence or absence of the existing propane facilities impacts total cost. In the first set, the Company also varied the size of the LNG storage tank, to determine which size is most cost effective. That analysis was discrete. Only three sizes were modeled, i.e. 2 Bcf, 1.2 Bcf, and 2.5 Bcf. The Company's analyses in its original testimony are summarized below in Table A.

**Table A: Company's Analysis In Its Direct Testimony***

| Planning Scenario | Granite Bridge LNG | Propane Facilities | Resource Mix Results (Dth/day) | | | Total System Cost ($000) | Comparison to Base Case ($000) |
|---|---|---|---|---|---|---|---|
| | | | Dawn | REPSOL [10] | ENGIE | | |
| Base Case 1.2 Bcf | 1.2 Bcf | No | 12,550 | 0 | 1,850 | 2,809,145 | 12,007 |
| Base Case | 2 Bcf | No | 9,470 | 0 | 0 | 2,797,138 | 0 |
| Base Case Sensitivity | 2 Bcf | Yes | 9,260 | 0 | 0 | 2,797,226 | 88 |
| Base Case 2.5 Bcf | 2.5 Bcf | No | 8,700 | 0 | 0 | 2,876,272 | 79,134 |
| Alternative Case | No | No | 6,840 | 105,360 | 1150 | 2,976,108 | 178,970 |
| Alternative Case Sensitivity | No | Yes | 19,230 | 51,210 | 7,000 | 2,800,530 | 3,392 |

* The Company's analyses use levelized costs for the Granite Bridge projects and a planning horizon of twenty years.

[10] REPSOL is an international energy company that has provided gas supplies (imported LNG) to EnergyNorth for both winter base load and winter call option historically by successfully responding to the Company's RFP for its winter supplies. The SENDOUT runs model that REPSOL delivers service with a MDQ of up to 150,000 Dth per day and a seasonal maximum capacity of 6,000,000 Dth for the entire forecast horizon. To know more about REPSOL, *see* www.repsol.com.

Based on the findings, EnergyNorth concluded that the "Base Case," which models a LNG storage facility of 2 Bcf (Base Case) while retiring its existing propane facilities, provides the most cost effective solution to its long-term supply needs.

**Q. Did the Company update its analysis later in this proceeding?**

A. Yes. The Company updated its analysis three times. First, the Company updated its original analysis to reflect the income tax regime that went into effect starting in 2018. Second, more substantively, it also later revised its demand forecast (Company's response to CLF TS-1.2, 06-27-2018, *see* Attachment PKC-1). Third, in March 2019, the Company provided supplemental testimony to update its analysis to reflect the effect of a newly signed Memorandum of Understanding (MOU) detailing a natural gas supply arrangement that may be implemented between EnergyNorth and Calpine to provide additional fuel security for GREC as a gas-fired wholesale electricity producer. That effect is reflected in the Company's SENDOUT analysis as a Customer Benefit Guarantee (CBG) modeled as a guaranteed reduction in the costs borne by ratepayers (discussed later in more detail). That update also included revised estimates on the costs of both the GBP and the LNG facility, adjusted the demand forecast to reflect the impact of the newly granted franchise in Epping to Northern Utilities,[11] and

[11] *See* Order Nos. 26,220 (February 8, 2019; granting franchise to Northern Utilities) and 26,229 (March 25, 2019; denying rehearing and noting that nothing in Order No. 26,220 "precludes Liberty from seeking franchise authority to serve some area of the Town") in Docket No. DG 18-094.

updated the pricing input data to reflect more contemporaneous forward market realities.

**Q. How have you organized the exposition of the Company's analysis?**

A. Given that the supplemental testimony reflects the Company's latest position, I have, going forward, critiqued the Company's scenario analyses as described solely in its supplemental testimony. While the OCA had previously conducted extensive discovery on the scenarios reflecting the Company's previous proposals, what matters at this point is whether the Company's latest proposal is in the interest of ratepayers or not. To frame that analysis properly, it is helpful to discuss, at least briefly, how the supplemental testimony materially differs from the Company's original testimony.

**Q. Please provide a brief description of how the supplemental testimony materially differs from the Company's original testimony.**

A. First, the introduction of the CBG involves a commitment from the Company that regardless of whether a contract with Calpine materializes, Liberty Utilities will provide its customers "the market value outlined in the Calpine MOU for the duration of the MOU's initial term."[12] Based on the Company's supplemental testimony and the discussions in a technical session, the OCA's understanding is that the Company is guaranteeing customers a benefit of [redacted], but will also provide additional credit to customers up to [redacted] to account for variable costs recovered from Calpine or

[12] *See* Supplemental Direct testimony of Mr. DaFonte and Mr. Killeen, Bates page 013, line 17.

any other party that executes a binding Precedent Agreement relative to LNG capacity available via the Granite Bridge Project. The CBG clause as proposed by the Company will be in effect for the initial [redacted] the LNG facility is operational.

Second, with respect to the demand forecast, the Company reduced its forecast slightly to reflect the new reality that another utility has been granted a natural gas franchise in Epping. This reduction amounts to 1,245 Dth on the design-day in winter of 2038-39.

Third, the Company revised its cost estimates for both the pipeline and the LNG projects. For the pipeline project, the Company's new cost estimate is $168 million, which is $53.6 million more than the original estimate. For the LNG facility, the Company's new cost estimate is $246 million, which is $44.3 million more than the original estimate. In percentage terms, the cost estimates have increased for the pipeline and the LNG facility by 47 percent and 22 percent, respectively. It is worth noting here that the new estimate for the pipeline is on a 30 percent engineering design basis. For the LNG facility, the new estimate is based on a preliminary design.

**Q. Please explain how the Company's SENDOUT analyses inputs in its supplemental testimony differ from the analyses inputs in its original direct testimony.**

A. The new SENDOUT analyses fundamentally differ from the original runs in five ways. First, the new runs reflect the income tax reality that went into effect in 2018.

Second, the initial project costs for both the pipeline and the LNG facility have been increased significantly to reflect the new cost estimates. Those new estimates are used to derive the yearly levelized costs using the same approach as before. For the pipeline, the yearly levelized cost estimate rose from $12.4 million to $17.6 million. For the 2.0 Bcf LNG facility, the yearly levelized cost estimate rose from $26.6 million to $28.8 million.

Third, the SENDOUT runs assume that customers benefit from a CBG payments of [redacted] million per year for the initial five years after the LNG facility becomes operational. For the purpose of modeling the CBG in SENDOUT, the company not only models the [redacted] million as a credit to the fixed cost associated with the LNG facility, but also models the additional [redacted] million of variable costs, as a fixed cost (credit to customers). Also, since the CBG is informed by the MOU between Calpine and EnergyNorth, the SENDOUT models assume that the storage available for the company's captive customers is the full capacity *less* [redacted] capacity assigned to Calpine (or any other party that executes a similar and binding Precedent Agreement). In a similar manner, the SENDOUT modeling also recognizes that the daily vaporization volume up to [redacted] is assigned to Calpine (or any other party that executes a binding Precedent Agreement) with an hourly maximum volume of [redacted].

Fourth, the demand forecasts are adjusted downward to reflect not only the adjustments made by the Company per its response to CLF TS-1.2, 06-27-2018 (*see*

Attachment PKC-1), but it also further adjusts the forecasts slightly to acknowledge that another utility has been subsequently granted a franchise in Epping.

Fifth, the Company also used forward markets data to update the pricing input into its SENDOUT analysis. The approach to modeling the pricing forecasts however has remained unchanged.

**Q. Please discuss the Company's SENDOUT analyses and its findings per its supplemental testimony.**

A. In connection with its supplemental testimony, the Company ran five SENDOUT scenarios. The first run, FCD/WRK-2, assumes the construction of the Granite Bridge Pipeline and 2.0 Bcf LNG storage facility, implementation of the CBG, and the retirement of Liberty's existing propane facilities. All of the other runs drop the effect of the CBG. FCD/WRK-3 also assumes away the existence of the LNG facility. FCD/WRK-4 assumes away the existence of the LNG facility but models the existing propane facilities as part of the supply portfolio. FCD/WRK-5 and FCD/WRK-6 simply model smaller sized LNG facilities, while assuming that the existing propane facilities are retired. Practically, FCD-WRK-3, FCD/WRK-4, FCD/WRK-5, and FCD/WRK-6 are akin to planning scenarios, Alternative Case, Alternative Case Sensitivity, Base Case 1.2 Bcf, and Base Case 1.5 Bcf, respectively, depicted in Table B, but with updated cost data for the project, the latest demand forecast, and pricing data reflecting more current market realities. *See* Table B below for the summary of the SENDOUT results.

**Table B: Company's Updated Analysis dated March 15, 2019***

| Planning Scenario/DR | GB LNG | Propane Facilities | Resource Mix Results (Dth/day) | | | Total System Cost ($000) | Comparison to Base Case ($000) |
|---|---|---|---|---|---|---|---|
| | | | Dawn | REPSOL | ENGIE | | |
| Base Case Supplemental CBG | 2 Bcf | No | 0 | 0 | 0 | 2,796,648 | 0 |
| Alternative Case Supplemental | No | No | 5,920 | 103,380 | 510 | 2978,425 | 181,777 |
| Alternative Case Supplemental Sensitivity | No | Yes | 0 | 60,940 | 7,000 | 2,820,168 | 23,520 |
| Base Case Supplemental 1.2 Bcf | 1.2 Bcf | No | 0 | 0 | 4,190 | 2,861,181 | 64,533 |
| Base Case Supplemental 1.5 Bcf | 1.5 Bcf | No | 0 | 0 | 1,970 | 2,838,078 | 41,430 |

* The Company's analyses use levelized costs for the Granite Bridge projects and a planning horizon of twenty years.

The analysis conducted by the Company found that building the 2.0 Bcf LNG facility inclusive of the CBG produces lower costs to the ratepayers relative to not building the facility (and the resulting absence of the CBG). It also found that building the 2.0 Bcf LNG facility inclusive of the CBG arrangement produces lower costs than relying on the propane facilities in the absence of any LNG facility. Further, it also found that building the 2.0 Bcf LNG facility in conjunction with the CBG arrangement produces lower costs than building either a 1.2 Bcf or 1.5 Bcf LNG storage facilities in the absence of the CBG arrangement. Even with the updated analysis, the Company maintains that the 2.0 Bcf LNG facility (albeit in conjunction with the CBG arrangement) is an element of the Company's optimal supply strategy. Therefore, the Company's request before the Commission for approval of the Granite Bridge Pipeline and the LNG facility remains unaltered.

## III. OCA's Critique of EnergyNorth's Supply Strategy Analysis

**Q. Is the Company's analysis informing its preferred supply strategy reasonable?**

A. No.

**Q. Please elaborate.**

A. As the Company's choice of the "best-cost" option is largely driven by its SENDOUT analyses, I have largely concentrated on critiquing these modeling results. The OCA has issues with several aspects of the Company's analyses. I summarize the issues below, before discussing each in greater detail.

(1) **Demand Forecasting.** The Company's solitary set of annual design-day forecasts is not soundly supported by a reasonably rigorous analysis, and is overly optimistic from the Company's perspective. In particular, the OCA has issues with the Company's adoption of an out-of-model adjustment for sales and marketing initiatives, the Company's modeling prospective franchises' demand, and the Company's modeling of iNATGAS demand.[13]

(2) **Levelized Cost Analysis.** Using levelized costs to represent ratepayers' annual burden over twenty years is unreasonable; non-levelized costs should be used instead, as that is exactly what the ratepayers will bear. Also, in estimating the burden on ratepayers, the analysis should consider a discount factor to reflect their time-preference.[14] I would expect most existing customers to discount materially what would transpire well into the future.

[13] iNATGAS, which provides Compressed Natural Gas (CNG) to areas not served by a traditional pipeline, has a special contract with EnergyNorth per Order No. 25,694 (July 15, 2014) in Docket No. DG 14-091. *See* www.inatgas.com for more information.

[14] In economics, time preference captures an individual's or a group's preference for receiving a good or service at an earlier date rather than receiving that good or service at a later date.

(4) **Planning Horizon.** I disagree strongly with the planning horizon being twenty-years. A significantly shorter planning horizon should be used to reflect more appropriately the interests of existing ratepayers, especially in view of the size of the Granite Bridge Project.

(5) **Propane Facility Retirements.** Finally, the Company has not demonstrated adequately the adverse impact of co-mingling propane-air with gas. To the extent continuing with the existing propane facilities may provide significant cost savings to ratepayers, the shutdowns of the Company's existing facilities cannot be assumed to justify the construction of the Granite Bridge Project as requested.

The OCA's modification to the Company's analysis as discussed in Section IV, and ultimately our recommendations later, are crucially informed by the discussions that follow in the subsections a., b., and c. below.

**IIIa. Demand Forecast**

**Q. Please summarize the Company's demand forecast.**

A. It is important first to point out that the Company's position at the time of filing this testimony actually differs from its original position as detailed in its direct testimony. Following discovery (informed by discussions in the first technical session), at the end of June 2018, the Company provided a detailed review of EnergyNorth's Demand Forecast, in response to DR CLF Tech 1.2; See Attachment PKC-1. While the Company acknowledged some of the erroneous inputs that were relied on in its initial petition, it concluded that even with necessary corrections, the forecasted demand was only slightly lower than what was used in the original petition. The design-day demand, for example, for 2037-38 changed from 229,590 Dth to 224,541 Dth. When the Company updated its demand forecast again in March 2019, the design-day demand changed only marginally to reflect that Unitil has recently been granted a franchise in Epping. Given the focus of my analysis, what needs to be stressed is that the Company's updated analysis did not change its findings with respect to what constitutes the most cost-effective approach when comparing the different SENDOUT scenarios that the Company had modeled in its original petition.

**Q. Do you have reservations about the Company's demand forecast, the updated review notwithstanding?**

A. Yes.

**Q. Please discuss your reservations about the Company's demand forecast.**

A. The Company's preferred strategy is crucially dependent on its demand forecast. Despite the Company's review that was shared in June 2018 (and slightly adjusted per its March 2019 Supplemental Testimony), I finds that the demand forecast the Company relied on its SENDOUT runs is overly optimistic. The Company's updated analysis continues to be predicated on some crucial assumptions with which I fundamentally disagree. These reservations are discussed below one-by-one.

First, I do not agree that the Company should include any demand forecast for areas where it has not even pursued franchise approvals yet.

Second, perhaps more disconcertingly, the Company has not demonstrated with any rigor why it is appropriate to rely on the out-of-model sales and marketing adjustment to augment the demand forecast for existing territories as proposed by the Company.

Finally, I disagree with the adjustment for iNATGAS, as modeled in the Company's review. The noted reservations are discussed below in greater detail.

**Q. Please elaborate on your reservation about accounting for demand from franchises for which the Company has not yet even sought approval before the Commission.**

A. To be appropriately conservative, demand projections attributable to presumed future franchises should not be counted when modeling the annual design-day demands in the Company's SENDOUT analyses. The situation in and around the Route 101 energy corridor is in a state of flux. It is overly optimistic to assume that not only will Liberty Utilities acquire necessary approvals but also start attracting customers in prospective franchises four to five years into the future. That optimism actually seems particularly suspect, given that another utility – Unitil -- has already been granted a franchise to provide service in Epping.

**Q. Please discuss the OCA's reservation about the Company's "out-of-model" adjustments for existing franchises to bolster the demand forecast.**

A. First, the Commission should not simply rely solely on the Company's assertion of its "experience and judgment of the professional staff" to accommodate an out-of-model sales and marketing adjustment for existing franchises on an incremental basis.[15] This cannot be considered prudent planning. While the OCA does not have issues per se with reasonably accommodating out-of-model adjustments, the fact that the Company is projecting a total out-of-model adjustment of 22 percent above its econometric forecast for a distant year like 2038-39, should give pause as to the reasonableness of the forecast. Second, even if recent initiatives may have produced an uptick in Liberty Utilities' consumer base (in its existing territories) that is not captured by the Company's econometric modeling, it is overly optimistic to assume out-of-model design-day adjustments for sales and marketing and prospective franchise expansions to the tune of 14 percent of the econometrically forecasted design-day demand for a distant year like 2038-39 (and no less incredibly, 13 percent for 2027-28). Most certainly, such an exaggerated design-day demand forecast from a distant year, which is not adequately justified, should not be driving major investment decisions as proposed in this docket.

**Q. Please provide the OCA's reservation about the Company's design-day forecast for iNATGAS.**

A. In updating the Company's forecast, Attachment Tech CLF 1-2.1 ( Attachment PKC-1) assumes that iNATGAS will have a design-day requirement of 8,800 Dth

[15] From the Company's response to OCA 2-22: "The methodology that the Sales and Marketing Group uses to forecast the growth for existing territories is based on the experience and judgment of the professional staff, who take into account historical growth results, new lead opportunities, and a focus on community development and municipality development. . . . The estimation methodology used by the Sales and Marketing Group for new territories is based on the experience and judgment of the professional staff, using customer prospect information provided by ICF International and local knowledge of natural gas penetration opportunities."

starting with split year 2022-23. It appears this requirement is predicated upon the Company's reliance on a contractual arrangement. The contractual agreement seems to be that of a take-or-pay clause that requires iNATGAS to pay for at least 1,300,000 Dth per year starting in year five of the Special Contract. It is not evident how the contractual clause has any bearing on the Company's design-day requirement. I do not find that the assumption of 8,800 Dth of design-day requirement has been sufficiently substantiated. I believe the design-day requirement associated with iNATGAS should be at best what has been demonstratively recorded until now. Confidential Response to DR PLAN 5-7 (Attachment PKC-2) indicates that the design-day requirement for split years even beyond 2020-21 reasonably should be assumed to be 4,251 Dth, i.e. the maximum daily send-out recorded for iNATGAS until now.

## IIIb. Levelized Costs, Discount Rate, and Planning Horizon

**Q. EnergyNorth has used levelized costs rather than annualized costs to capture the annual burden of the Granite Bridge Project on ratepayers. Do you agree with that approach?**

A. No.

**Q. Please elaborate.**

A. From the perspective of ratepayers, a proper comparison of alternatives – even if the alternatives are contracts with constant annual costs across years – with Liberty Utilities' Granite Bridge Project should be based on modeling of the Granite Bridge

Project's annualized (non-levelized) costs. Ratepayers are faced with time-variant annual revenue requirements resulting from the two constituent projects (pipeline and LNG storage) being operational. That needs to be directly modeled in SENDOUT.

**Q. Does the modeling of annualized costs instead of levelized costs, ceteris paribus, alter the Company's conclusion that the GBP is more cost-effective than a contract with TGP for incremental capacity on Concord Lateral? Please explain your answer.**

A. No. Based on the cost estimates assumed by the Company for Concord Lateral and lately projected for the GBP, even with annualized costs for the GBP, Concord Lateral costs more than the GBP (as proposed by the Company) for every year regardless of whether one opts for a 20-year or a 10-year planning horizon. Since the SENDOUT runs model these costs as fixed costs, with everything else held constant, the resulting total costs for the alternatives vary exactly by the difference between the fixed costs. Given that for each year the transportation demand cost associated with Concord Lateral (per EnergyNorth's filing) is higher than the revenue requirement associated with GBP, the conclusion that GBP is more cost-effective than Concord Lateral continues to hold.

**Q. Since the Company's conclusion about the cost-effectiveness of GBP relative to Concord Lateral capacity expansion does not change whether GBP's initial project cost is modeled as annualized costs or levelized costs, do you still insist on using annualized costs rather than levelized costs? Please explain your answer.**

A. Yes. In properly capturing ratepayers' interests, it is important to acknowledge first that ratepayers have time preferences that necessitate discounting future costs.

When comparing their burdens under alternative options with appropriate discounting, it is important to track what ratepayers are actually expected to pay. A proper comparison of ratepayers' burdens between alternatives, with an acknowledgement of a reasonable discount factor, requires modeling the GBP initial project cost as annualized costs. Indeed, analyzing whether there should be a LNG facility as proposed by Liberty Utilities or not (which is a paramount focus of the Company's petition) requires modeling both annualized costs for the proposed Granite Bridge LNG and GBP projects as well as acknowledging ratepayers' discount rate associated with their time preference. In what follows, my analysis not only relies on modeling the annualized costs, but also applies time-preference discounting to capture existing ratepayers' interests in a reasonable fashion.

**Q. With respect to modeling a discount factor to reflect ratepayers' time-preference, please provide additional thoughts that you believe are contextual.**

A. I would expect existing ratepayers to discount costs that are well into the future significantly more than near term future costs. It is not unreasonable to expect, for example, some ratepayers discounting costs initially for the first five years at a rate of 5 percent per annum, while costs beyond five years at a rate of 10 percent per annum. This could be due to the simple fact that many residential customers do not expect to stay put in one region too long. Importantly though, when judging the cost-effectiveness of a project (especially a large one), we should significantly acknowledge the interests of existing customers, when evaluating the potential project. Given how the choice of a planning horizon and the focus on the design-day requirement skews the misalignment of benefit and ratepayer burden for an existing customer, I believe it is reasonable to model a discount factor of 6 percent to capture ratepayers' time-preference keeping in mind the interests of existing ratepayers.[16] I contend that such a discounting reasonably captures expectations about inflation as well as other risks borne by existing ratepayers for the proposed large project.[17]

**Q. Do you agree with the Company's choice of the planning horizon? Please explain your position.**

A. No. First, a 20-year planning horizon in a growth environment gears the planning towards a design-day requirement that is so far into the future that costs are invariably borne unreasonably by existing customers, most definitely when a new project of a significant size is pursued.

**Q. Is it your position that there should not be any front-loading of costs without commensurate benefits?**

A. No. But, while it is well understood that with capital-intensive projects, there is inevitably some front-loading of costs without commensurate benefits to existing customers, care should be taken in ensuring that the Commission does not expose

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[16] In calculating the Net Present Value (NPV) of the annualized costs, the Company had used a discount rate of 6.10 percent "in order to account for the time value of money." *See* Direct Testimony of Timothy S. Lyons, Bates page 094, Line 9.

[17] While I believe that using 6 percent as the discount factor is reasonable, I am aware that there is a degree of subjectivity in representing what a reasonable discount factor might be in aggregate for existing ratepayers. I have therefore, for the salient comparisons that follow in section IV, have also examined the implications of using a discount factor of 3 percent. As discussed later, the fundamental results of my analysis do not change even when I assume a discount factor of 3 percent.

existing customers to a cost-benefit mismatch that is innately unjust. Indeed, it is not a coincidence that the Least Cost Integrated Resource Plans (LCIRPs) before the Commission are predicated on analyses that assume time horizons of five years.[18] Given a proposed planning horizon of 20 years, a demand projection that is almost certainly optimistic, the resulting scale of the project (more than doubling of Liberty Utilities' rate base[19]), and simple reality that existing customers are being asked to incur costs now to meet needs of future customers, the cost-benefit mismatch for existing customers is acute enough that the Commission should reject the proposed planning horizon.

**Q. Do you see other issues with using a 20-year planning horizon?**

A. Yes. Not trivially, a lot can change in 20 years. Energy production technology and the policy climate could drastically change in twenty years to render the proposed projects stranded investments. With respect to costs, unanticipated expenses could potentially significantly increase the annual revenue requirements that emanate from the proposed projects. For example, if the corporate tax regime reverts back to the pre-2018 situation, the resulting cost impact may not be trivial. Also, the initial cost as proposed by Liberty Utilities may turn out to have been materially underestimated. Further, the demand realities can pan out to be significantly less rosy than what has

[18] *See* EnergyNorth's Least Cost Integrated Resource Plan (LCIRP) in Docket DG 17-152, Pages 5-7, and Northern Utilities' 2019 Integrated Resource Plan in Docket DG 19-126, Pages I-1 to I-4.

[19] Whether the initial project cost is recovered through delivery rates or cost-of-gas, the costs will be predominantly borne by Liberty Utilities' sales customers.

been modeled by EnergyNorth. The company's design-day projection associated with the twentieth year is fraught with a great deal of uncertainty. The fact that EnergyNorth has relied on just a solitary demand projection only makes things worse. Given the scale of the project as proposed, I strongly contend that it is unreasonable and unjust to expect existing customers to be burdened with costs predicated on such a design-day requirement, purely due to the uncertainty factor.

**Q. What in your view is a reasonable planning horizon?**

A. The planning horizon should not go beyond 2028-29 in the instant docket.[20] Such a planning horizon appropriately takes into account the uncertainty with how the future would play out, and to what extent existing customers can reasonably bear the burden of costs largely driven by reliability considerations, particularly given that those considerations relate to future customers.

**Q. How have other local distribution companies (LDCs) viewed the planning horizon question?**

A. The other New England LDCs that have also signed precedent agreements with PNGTS have relied on planning horizons of roughly ten years or less (and Northern

[20] Not trivially, in Docket No. DG 07-101, KeySpan, consistent with its LCIRP filed in Docket No. DG 06-105, had used a planning horizon of five years. The OCA contends that, ideally, EnergyNorth's analysis of its optimal supply strategy in this instant docket should also use a planning horizon of five years, consistent with the approach relied on in its contemporaneous LCIRP. The OCA, however, does believe that a planning horizon of ten years is still reasonable, given that the construction of a project like the one at issue in this docket is expected to take several years. Later in my testimony it will be evident that the OCA has effectively relied on a planning horizon of seven years (even though the SENDOUT models rely on a planning horizon of 2018-19 to 2028-29, i.e., eleven years) for our comparative analytics in determining the optimal strategy. That falls well within the range of what would be reasonably consistent with the planning horizon relied on in the Company's LCIRPs.

Utilities has actually relied on a 2020-21 design-day forecast to justify its Portland Express Project (PXP) contract of 10,000 Dth per day). A Canadian utility (Heritage Gas Limited), which has also signed a precedent agreement with PNGTS, in contrast, has relied on a 22-year planning horizon (see Company's response to OCA 2-21, Attachment PKC-3). In each of these instances though, to the best of my understanding, none of the filings had requested approvals of project build-outs, as is the case with Liberty Utilities.

**Q. Have you further explored the docket in which Heritage Gas Limited had used a planning horizon of 22 years?**

A. Yes. In the case of Heritage Gas Limited, the contracted amount (10,000 Dth per day) is significantly less than what Liberty Utility is seeking through building its Granite Bridge facilities (150,000 Dth per day). Heritage Gas Limited has historically relied more on short-term, delivered supply arrangements from off-shore Nova Scotia production, but has lately started valuing long-term contractual arrangements more than before. While I disagree with the use of a 22-year planning horizon for portfolio optimization, given the modest size of the requested incremental firm long-term supply there, I conclude that the existing customers of Heritage Gas Limited are not unreasonably exposed to costs unaligned with the benefits.

The conclusion, for a significant build-out that EnergyNorth has requested in this docket, would be however starkly different. A 20-year planning horizon would result in significant misalignment of costs and benefits to the detriment of existing customers.

Essentially, EnergyNorth's reliance on a planning horizon that is four times the planning horizon employed in its LCIRP, ignores the brunt of significant cost burden faced by existing customers, without receiving commensurate benefits from the major build-outs that the Company has requested in this docket.

**IIIc. EnergyNorth's Existing Propane Facilities**

**Q. Please summarize EnergyNorth's position with respect to its existing propane facilities.**

A. The Company asserts that in the future it may have to "inevitably retire" its existing propane facilities.[21] When queried about when that might happen, the Company did not respond with a timeline, but instead suggested that having the LNG facility would give the Company flexibility in determining when to retire the propane facilities. Once we assume that the Granite Bridge Pipeline materializes, the OCA essentially understands EnergyNorth's position to be that building the LNG facility as proposed while retiring the propane facilities is more cost-effective than not building the LNG facility while keeping the propane facilities in service.

**Q. What is the OCA's understanding of the current reality with EnergyNorth's existing propane facilities?**

A. The Company currently does a good job of maintaining its propane facilities, and at a very reasonable cost. The remaining undepreciated book value of the assets is less

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[21] *See* Direct Testimony of William R. Killeen and James M. Stephens, Bates Page 118, Lines 5-6.

than $50,000. It appears that the Company continues to depend on these facilities to meet its supply needs.

The Company nevertheless gripes that high-efficiency furnaces may experience trouble when propane-air is introduced into the distribution system, but does not provide demonstratively specific instances in which such high-efficiency furnaces clearly stopped working due to the introduction of propane-air outside the tolerable limits. In response to DR OCA 2-37 in DG 17-198 and DR Staff 2-12 in Docket DG 17-152 (Attachment PKC-4), the Company asserts that it has received multiple complaints from customers with new high-efficiency heating equipment as a result of EnergyNorth's use of the propane facilities, and shares a Facebook complaint from a customer. The OCA followed up with data requests OCA 3-1 and OCA 5-3, OCA 5-4 and OCA 5-5 (*see* Attachment PKC-5), specifically querying the Company about whether the multiple instances that it cites in response to Staff 2-12 in DG 17-152 were verified, and whether the Facebook complainant's "no heat" situation was indeed due to injection of propane-air into the distribution system. Based on the Company's response, I cannot conclude that the specific situation was indeed necessarily the result of injection of propane-air into the gas distribution system. Based on the information provided in response to data request OCA 3-1 (*see* Attachment PKC-5), that there may have been some instances in which injection of propane could have been an issue, but overall the issue of comingling propane into natural gas is not significant enough to justify the alternative path that the Company has proposed.

**Q. Is comingling of propane-air with natural gas a significant enough concern that the existing propane facilities should be abandoned as a result?**

A. No. I do not believe that the Company has met the burden of proof in making a case that the injection of propane-air into the distribution system is an overriding problem. Also, even if the Company had met the burden of proof, it is not evident that there may not be some other solution that is cheaper than building a very expensive LNG facility simply to permit flexibility in retiring the propane facilities sometime in the future.

**Q. Could there be a good reason to consider a path toward retiring EnergyNorth's existing propane facilities? Please explain your position.**

A. Yes. Under reasonable assumptions about ratepayers' cost incidence, building the LNG facility as proposed while retiring the propane facilities may be more cost-effective than not building the LNG facility while retaining the propane facilities. In that event, building the LNG facility as proposed may be reasonable in conjunction with a careful consideration of a plan to retire EnergyNorth's existing propane facilities. Whether that is the case is an important aspect of this docket. In Section IV, the OCA essentially builds upon the Company's SENDOUT analyses, by altering some the Company's assumptions with which we disagree and adding considerations to reflect the ratepayers' interests. We did this to determine whether the OCA agrees with the Company's finding that it is more cost-effective to pursue the Granite Bridge LNG

Project in lieu of continuing to rely on the existing propane facilities, with a reasonable planning horizon, ceteris paribus.

**Q. Please summarize Section III.**

A. EnergyNorth's assumptions about future demand are overly optimistic. Additionally, given the pricing trends in gas futures and forwards, the Company's assumptions about future prices at Dracut are not reasonable. With respect to modeling costs pertaining to the initial project costs, it is vital to model annualized costs instead of levelized costs, as was relied upon in the Company's petition. In our view, it is also important to apply a discount factor so to acknowledge ratepayers' time preference. Further, I strongly disagree with the use of a planning horizon of 20 years. We instead recommend using a planning horizon of around 10 years. Last but not least, whether the Granite Bridge LNG should be approved should turn on a demonstration of whether it is more cost-effective to pursue the Granite Bridge LNG Project in lieu of retaining EnergyNorth's existing propane facilities.

**IV. OCA's Analysis and Findings on EnergyNorth's Supply Strategy**

**Q. Please describe how you have organized your analysis informing the OCA's recommendation on EnergyNorth's Supply Strategy.**

A. The major focus our work in this docket so far has involved a rigorous look at SENDOUT data from the Company that assumes the construction of the Granite Bridge Pipeline, which thus sheds light on the question of whether to build the LNG facility.

Those SENDOUT runs presume that GBP is a necessary component to the Company's supply strategy in solving the transportation bottleneck created by the over-dependency on TGP's Concord Lateral. In reaching that conclusion, the Company compared the build-out of Granite Bridge Pipeline with only one possible alternative – a possible contract with TGP to expand the capacity on Concord Lateral. I therefore first consider whether the Company has adequately supported the presumption that Granite Bridge Pipeline is a necessary component of EnergyNorth's supply strategy. That discussion is in subsection IVa.

Subsection IVb. focuses on SENDOUT-centric analyses to investigate whether the OCA agrees with the Company that the LNG facility as requested by it is warranted at this time. The key inputs into the OCA's analyses that vary from what were assumed by the Company have already been discussed in detail in the previous section, and will be repeated appropriately in the discussions in subsection IVb.

**IVa. Cost-effectiveness of the Granite Bridge Pipeline Project**

**Q. EnergyNorth concluded that the Granite Bridge Pipeline is an essential component of its "best-cost" supply strategy. Does the OCA believe that this conclusion has been adequately supported?**

A. No. In reaching the aforementioned conclusion, the Company limits the cost-effectiveness question to a comparison of the Granite Bridge Pipeline to the potential contract with TGP for Concord Lateral expansion. The question that lingers concerns other alternatives to the proposed Granite Bridge Pipeline (including some potential alterations to the proposed Granite Bridge Pipeline). It is not evident why it is a settled conclusion that the Concord Lateral is the only available alternative to the Granite Bridge Pipeline. I am not expressing a definitive opinion on this question at this time, beyond noting my understanding that it is the Company's burden to demonstrate the construction of the pipeline warrants approval by the Commission under the applicable legal standard.

**Q. Given that you do not believe that EnergyNorth's has adequately vetted its conclusion that the Granite Bridge Project is an essential component of its "best-cost" supply strategy, is it useful and appropriate to consider SENDOUT analyses that presume Granite Bridge Pipeline to be an integral part of EnergyNorth's future portfolio?**

A. Yes. The question of whether the Granite Bridge Pipeline (or some variant) may be needed hinges on how realistic the Company's forecast of future year design-day demand is. We believe the Company's forecast is over-optimistic. But, even applying an alternative forecast (on which the OCA relies upon to adjust the forecasts downward in a conservative fashion, as discussed later), it is evident that by building the pipeline EnergyNorth would be afforded at best few more years with respect to producing a feasible solution to the Company's needs. Even with a planning horizon of about ten years, relying strictly on the Company's cost estimates, it is apparent that to implement a feasible solution to EnergyNorth's customers' needs the Company will need access to incremental feasible supplies. Based on the Company's cost estimates, the GBP option is more cost-effective than the Concord Lateral option. I therefore conclude that, at a minimum, it is helpful to frame the question of the cost-effectiveness of LNG facility by assuming, as an option, that GBP is part of EnergyNorth's transportation infrastructure. I would urge the Commission to view my analysis that follows in that vein.

**Q. Does the OCA have any additional comments in concluding this subsection?**

A. Yes. While on the issue of the reasonableness of the Granite Bridge Pipeline project, one line of inquiry of course is expected to be whether the sizing of the Granite Bridge Pipeline as proposed by the Company is reasonable. It is worth observing that the Company, before the project costs were updated, had estimated that the savings on the initial project cost by scaling the diameter of the pipeline down from 16 inches to 12 inches would be about $3 million. To the extent that the greater diameter is unnecessary in meeting ratepayers' needs, even with minimal net savings, ratepayers should not be burdened by an unnecessarily over-sized pipeline. The OCA has not probed this issue, but would note for the benefit of the Commission that one of the outstanding questions could be whether the requested diameter size for Granite Bridge Pipeline is reasonable, assuming that Granite Bridge Pipeline remains an element of the company's optimal supply strategy.

**IVb. Cost-effectiveness of the Granite Bridge LNG facility**

**Q. Briefly discuss how subsection IVb. is organized.**

A. The key changes to the inputs and assumptions that inform the OCA's analysis were discussed in Section III. Organizationally, in subsection IVb.1., we first discuss the findings from the SENDOUT analyses by keeping the Company's latest demand and pricing forecasts intact by modeling the updated project costs for the GBP and the LNG facility as annualized costs, using planning horizons of both twenty years and ten years, respectively, and by modeling a 6 percent time-preference discount factor for ratepayers.

Subsection IVb.2. focuses on the SENDOUT analyses that not only model annualized costs, and a discount rate of 6 percent to reflect ratepayers' time-preference, but also models a conservative demand forecast, using planning horizons of twenty and ten years, respectively.

Subsection IVb.3. focuses on another forecast scenario that is less optimistic than the Company's projection but is more upbeat relative to the OCA's forecast scenario. It is important to reiterate here that in what follows, we rely on the latest cost and demand forecast estimates provided by the Company. The discussion here largely focuses on the Company's responses to data requests that were propounded after it filed its supplemental testimony.

IV.b.1 Analysis Under Company's Demand Forecast

**Q. Please discuss how the annualized costs and the shorter planning horizon were modeled.**

A. Data requests Staff 12-2, OCA 12-5, OCA 13-1.a and OCA 13.1.b requested the Company to conduct SENDOUT runs that model the initial Granite Bridge project costs as annualized costs with cost-optimization horizons of both 2018 to 2039 (as modeled by the Company) *and* the shorter horizon of 2018 to 2029, respectively, using its updated forecast per the Company's supplemental testimony. The Company's responses to these data requests inform the analysis that follows. For ease of comparison, the tables that follow in this subsection show results based on the Company's responses to the aforementioned data requests in the same form as that of Table 9 of the Direct Testimony of Mr. Killen and Mr. Stephens, by also modeling a discount factor of 6 percent.

**Q. Please explain your approach towards modeling the discount rate to reflect ratepayers' time-preference.**

A. Since the LNG project as proposed is expected to be operational in 2022-23, when examining the cost-effectiveness of different options I have relied on estimating net-present value of costs for years 2022-23 to 2038-39, for a 20 year planning horizon, and 2022-23 to 2028-29, for a 10 year planning horizon. This approach is reasonable because such an analysis is predicated on the project being in place as well as being used and useful. Also, the differences in the costs among the different scenarios across years until 2022-23 are really negligible. Therefore, when judging the cost-effectiveness of different options, the OCA has relied on the discounted total costs for the period 2022-23 to 2028-29 *and* 2022-23 to 2038-39, as relevant. As for the annual discount rate, the OCA has used 6 percent for all years. The reasoning behind that choice has been discussed previously in Section III.

**Table 1: Supplemental Testimony SENDOUT Runs/Planning Horizon of 20 years/Annualized Costs with Discounting (2022-39)***

| | | | Resource Mix Results (Dth/day) | | | | |
|---|---|---|---|---|---|---|---|
| Planning Scenario | GB LNG | Propane Facilities | Dawn | REPSOL | ENGIE | Total System Cost ($000) | Comparison to Base Case CBG ($000) |
| Base Case 1.2 Bcf | 1.2 Bcf | No | 0 | 0 | 4190 | 1,642,955 | 39,352 |
| Base Case 1.5 Bcf | 1.5 Bcf | No | 0 | 0 | 1970 | 1,630,692 | 27,090 |
| Base Case | 2 Bcf | No | 0 | 0 | 0 | 1,619,138 | 15,536 |
| Base Case CBG | 2 Bcf | No | 0 | 0 | 0 | 1,603,602 | 0 |
| Alternative Case | No | No | 0 | 100,280 | 510 | 1,700,763 | 97,161 |
| Alternative Case Sensitivity | No | Yes | 0 | 60,940 | 7,000 | 1,591,456 | (12,146)** |

* Based on response to OCA 13-1.a, and OCA 12-2.a. See Schedules PKC-1a and PKC-1b for details.
** With a discount factor of 3 percent, this delta is - $4.8 million.

**Q. Please discuss the findings of the OCA analysis that models the Company's demand and pricing forecasts and planning horizon, but applies a discount rate of 6 percent and uses annualized costs for the Granite Bridge Project.**

A. As Table 1 shows, when the initial project cost is annualized and a discount rate of 6 percent is used to represent ratepayers' time preference, the Company's finding, that building the LNG facility in lieu of its existing propane facilities is more cost-effective, is no longer valid. The Base Case run even with the Customer Benefit Guarantee is found to be $12 million (in net present value terms) costlier than the Alternative Case Sensitivity run. So even with a planning horizon of 20 years, when the Granite Bridge Project's initial build-out costs are annualized and the ratepayers' discount rate is reasonably acknowledged, building the LNG facility in lieu of its existing propane facilities is not cost-effective, even given that the demand forecast is overly optimistic.

Indeed, as will be discussed in the next section, when a reasonably conservative demand forecast is modeled, the Company's assertion that building the LNG facility rather than continuing with its existing propane facilities is cost-effective, is even more suspect. Also, not trivially, building upon the Company's response to OCA 12-2 (*see* Schedule PKC-1a for details), that relies on the Company's demand forecast, it is amply evident that even with a modest Granite Bridge Project cost overrun of just 5 percent (relative to the Company's estimates), the ratepayers would be better off by a whopping $28.7 million (on a net present value basis (2022-23 through 2038-39) using 6 percent discount factor) with the Company continuing with its propane facilities rather than building the proposed LNG facility.

To further drive home the point about cost escalation, it is worth noting that if we were to rely on the levelized costs (the Company's approach), as can be observed from the Company's analysis of scenarios with levelized costs, the "with propane, without LNG storage" situation would be costlier relative to the "no propane, with LNG storage" situation (including the CBG) by $23.5 million. But with just a five percent increase in the initial project costs associated with the Granite Bridge Project, one can show that the advantage would disappear.

Table C below provides a summary of the resultant cost differentials between the Base Case Supplemental with CBG scenario (FCD/WRK-2) and the Alternative Case Sensitivity Supplemental scenario (FCD/WRK-4; retain propane, no LNG storage facility) under the levelized and the annualized (with 6 percent discount factor) approaches, assuming different percentage escalations in Granite Bridge Project's initial cost (Company's estimate from its Supplemental Testimony).

**Table C: Cost Differential (Million $) between Scenarios FCD/WRK-4 and FCD/WRK-2 under different Cost Escalations* (Company's forecast & 20-years' planning horizon)**

| Escalation (%) | Company's Approach (Levelized) | OCA's Approach (Discounted** Annualized) |
|---|---|---|
| 0 | 23.5 | -12.1 |
| 5 | -0.4 | -28.7 |
| 10 | -24.2 | -45.3 |
| 15 | -48.1 | -61.8 |
| 20 | -72.0 | -78.3 |
| 25 | -95.9 | -94.9 |

* The analysis builds upon Company's response to DR OCA 12-2.a.
** Based on 6 percent discount rate

Table C shows how escalation in the initial project cost estimate would adversely impact the viability of the Company's preferred strategy even per its own analytics. A modest 10 percent increase in the initial cost of the Granite Bridge Project would make the "no propane, with LNG storage" strategy $24.2 million costlier than the "with propane, without LNG storage" strategy. The OCA strongly contends that the Commission should not allow the Company to build the LNG facility based on such a tenuously justified set of assumptions about the future. The Company has not demonstrated that the option it prefers is robustly cost-effective relative to other alternatives.

Of course, as has been discussed in Section III, the 20 year planning horizon to support a build-out of a large project is inherently fraught with unreasonable risk to both existing and future ratepayers. A more reasonable approach is to model a planning horizon of 10 years. I therefore next discuss the findings when a planning horizon of ten years is used instead of twenty years.

**Q. Please discuss the findings of the OCA analysis that models the Company's demand and pricing forecasts, but models a 10 years' planning horizon, a discount rate of 6 percent, and uses annualized costs for the Granite Bridge Project.**

A. Table 2 below succinctly provides the results.

**Table 2: Post Supplemental Testimony SENDOUT Runs/Planning Horizon of 10 years/Annualized Costs with Discounting (2022-29)***

| Planning Scenario/DR** | GB LNG | Propane Facilities | Resource Mix Results (Dth/day) Dawn | REPSOL | ENGIE | Total System Cost ($000) | Comparison to Base Case ($000) |
|---|---|---|---|---|---|---|---|
| Base Case 1.2 Bcf | 1.2 Bcf | No | 0 | 0 | 0 | 835,104 | 18,736 |
| Base Case 1.5 Bcf | 1.5 Bcf | No | 0 | 0 | 0 | 832,293 | 15,925 |
| Base Case | 2 Bcf | No | 0 | 0 | 0 | 832446 | 15,177 |
| Base Case CBG | 2 Bcf | Yes | 0 | 0 | 0 | 816,368 | 0 |
| Alternative Case | No | No | 0 | 78,810 | 3,060 | 822,943 | 6,574 |
| Alternative Case Sensitivity | No | Yes | 0 | 38,990 | 7,000 | 777,909 | (38,460)** |

* With a 6 percent discount factor; The analysis relies on responses to OCA 13-1.c and OCA 12-5.b. See Schedules PKC-2a and PKC-2b for details.
** With a discount factor of 3 percent, this delta is - $40.2 million.

When the annualized costs and a reasonable planning horizon are appropriately acknowledged, and a reasonable discount rate to reflect the ratepayers' time-preference is modeled, the Alternative Case Sensitivity, which assumes that the propane facilities are retained in lieu of the LNG facility, produces over $38 million net-savings (net-present value basis) for ratepayers, over the planning horizon, compared to the 2 Bcf LNG storage with CBG scenario.

Another finding, relative to the results produced under the Company's analysis, is that the Company's optimal portfolio includes REPSOL to the tune of 39,000 Dth per day and ENGIE to the tune of 7,000 Dth per day. The Company had disclosed in the first technical session (held on May 24, 2018) that it did not find necessary to pursue a long-term contract with REPSOL as the Company's preferred option, because its analysis did not result in REPSOL being included in the optimal portfolio. When the annualized costs and a reasonable planning horizon are appropriately acknowledged, and a reasonable discount rate to reflect the ratepayers' time preference is modeled, however, the OCA's analysis shows that REPSOL is part of the optimal portfolio under the Company's optimistic forecast scenario. Also noteworthy is that, while the contract with ENGIE is part of the optimal mix, the analyses shows that EnergyNorth does not require any supplies on the Dawn to PNGTS path. Whether the overarching resource mix reality prevails even under a conservative demand forecast is discussed in the next section.

IVb.2 Analysis Under OCA's Demand Forecast

**Q. Please provide and discuss the basis for the OCA's Forecast Scenario.**

A. As was discussed in Section IIIa, I do not agree with the Company's reliance on substantial out-of-model adjustments to its econometrically forecasted demand to reflect its enhanced sales and marketing initiative in existing franchises and growth prospects in new franchises along the Route 101 energy corridor that are not yet before the Commission for approvals. It is not sufficient to rely simply on "professional experience" of the Company's sales and marketing workforce to augment the forecasted demand, as significantly as the Company does, in particular for periods more than ten years into the future (*see* footnote 15). The Company should rely on a more conservative demand forecast scenario with respect to purely prospective future franchise growth. Also, as was discussed previously, the iNATGAS design-day demand projection should be tempered. Finally, it is important that multiple forecast scenarios are investigated. Since the Company has relied on a solitary, overly-optimistic scenario, it becomes imperative that a more conservative demand scenario also be examined. As it turns out, even before the supplemental testimony was filed, Commission Staff had requested SENDOUT runs on more conservative demand forecasts. So did the OCA. The OCA's demand forecast scenario was very similar to the one that the Staff has requested in DR Staff 5-17.b.ii. Since the Company's response to DR Staff 5-17.b.ii had more comprehensively modeled the alternative forecast, the OCA finds it reasonable to adopt the Staff's scenario per its request in DR Staff 5-17.b.ii. Subsequently, with the filing of the supplemental testimony, the OCA through discovery, caused the Company to conduct SENDOUT analyses on the slightly adjusted design-day demand trend akin to that modeled in response to Staff 5.17.b.ii. Table D below reports that design-day forecast in conjunction with the Company's latest forecast for comparison.

**Q. Please explain the information provided in Table D.**

A. Table D reports the Company's design-day forecast and the OCA's conservative forecast for which we had requested SENDOUT analysis.

The last two columns of the Table compare the OCA's forecast scenario with both the Company's total forecast and the econometric forecast.

**Table D. OCA versus the Company's Design-Day Forecast Scenarios (Dth)**

| Split-Year | OCA's Scenario | Company's Scenario* | | Delta | |
|---|---|---|---|---|---|
| | | Econometric Forecast (EF) | EF + With other adjustments (WOA) | OCA Scenario *less* EF | OCA Scenario *less* EF + WOA |
| 2017/2018 | 157,292 | 156,240 | 157,848 | 1,052 | -556 |
| 2018/2019 | 162,668 | 157,306 | 164,571 | 5,362 | -1,903 |
| 2019/2020 | 164,068 | 158,604 | 167,643 | 5,464 | -3,575 |
| 2020/2021 | 163,212 | 157,645 | 168,942 | 5,567 | -5,730 |
| 2021/2022 | 166,310 | 160,639 | 174,618 | 5,671 | -8,308 |
| 2022/2023 | 173,349 | 162,438 | 183,409 | 10,911 | -10,060 |
| 2023/2024 | 175,651 | 164,055 | 187,625 | 11,596 | -11,974 |
| 2024/2025 | 177,206 | 165,298 | 191,536 | 11,908 | -14,330 |
| 2025/2026 | 178,764 | 166,538 | 194,985 | 12,226 | -16,221 |
| 2026/2027 | 180,308 | 167,764 | 198,167 | 12,544 | -17,859 |
| 2027/2028 | 181,410 | 168,550 | 200,701 | 12,860 | -19,291 |
| 2028/2029 | 183,063 | 169,885 | 203,518 | 13,178 | -20,455 |
| 2029/2030 | 184,709 | 171,215 | 206,136 | 13,494 | -21,427 |
| 2030/2031 | 186,566 | 172,756 | 208,770 | 13,810 | -22,204 |
| 2031/2032 | 188,381 | 174,255 | 211,155 | 14,126 | -22,774 |
| 2032/2033 | 190,263 | 175,822 | 213,519 | 14,441 | -23,256 |
| 2033/2034 | 192,246 | 177,489 | 215,841 | 14,757 | -23,595 |
| 2034/2035 | 194,124 | 179,050 | 217,910 | 15,074 | -23,786 |
| 2035/2036 | 195,775 | 180,386 | 219,616 | 15,389 | -23,841 |
| 2036/2037 | 197,668 | 181,965 | 221,459 | 15,703 | -23,791 |
| 2037/2038 | 199,579 | 183,561 | 223,318 | 16,018 | -23,739 |
| 2038/2039 | 200,375 | 185,282 | 225,306 | 15,093 | -24,931 |

* The Company's Scenario based on Table 1, Bates page 053 of its Supplemental Testimony, and Company's response to DR OCA 12-1.

As is evident from Table D, the OCA's scenario is not as optimistic as has been assumed by the Company, but still accommodates fairly substantial out-of-model adjustments relative to the Company's econometric forecast.

**Q. Please explain why do you believe that the forecast scenario modeled per DR OCA 12-18 is a reasonable forecast on which to base the SENDOUT analyses?**

A. Adjusting the demand forecast scenario for the reasons I discussed in the beginning of this section would, for example, result in a design-day requirement in 2038-39 of roughly 192,000 Dth compared to the Company's figure of 200,375 Dth. Relying on the forecast modeled per data request OCA 12-18 builds in a reasonable buffer. I am mindful that SENDOUT analyses (especially with changes in forecast scenario) tend to be time consuming. Therefore, I have relied on the analyses conducted in response to data request OCA 12-18.

**Q. Please discuss the results of your analysis that models the Company's pricing forecast and planning horizon, but employs a discount rate of 6 percent, uses annualized costs for the Granite Bridge Project, and substitutes the OCA's demand forecast for that of the Company.**

A. Table 3 below summarizes my findings based on the SENDOUT analyses reported by the Company in response to OCA 12-18 (OCA's demand forecast). To keep the discussions focused on the most relevant comparisons, the Table below reports planning scenarios with the Customer Benefit Guarantee for a 2 Bcf LNG tank size, Base Case (without the Customer Benefit Guarantee) for a 2 Bcf LNG tank size, and the Alternative Sensitivity Case (No LNG facility, but retain existing propane facilities).

**Table 3: OCA's Demand Forecast with Planning Horizon of 20 years/Annualized Costs with Discounting (2022-39)***

| | | | Resource Mix Results (Dth/day) | | | | |
|---|---|---|---|---|---|---|---|
| Planning Scenario | GB LNG | Propane Facilities | Dawn | REPSOL | ENGIE | Total System Cost ($000) | Comparison to Base Case ($000) |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| Base Case | 2 Bcf | No | 0 | 0 | 0 | 1,475,380 | 21,486 |
| Base Case CBG | 2 Bcf | No | 0 | 0 | 0 | 1,453,894 | 0 |
| Alternative Case Sensitivity | No | Yes | 0 | 35,830 | 7,000 | 1,400,936 | (52,957)** |

* The OCA relied on the information provided in response to OCA 12-18.e and OCA 14-4. See Schedules PKC-3a and PKC-3b for details.
** With a discount factor of 3 percent, this delta is - $54 million.

As is evident, even with a planning horizon of 20 years, when the initial Granite Bridge Project's cost is modeled on an annualized basis, and a reasonable discount rate to reflect ratepayers' time preference is used, employing a more realistic demand forecast leads to the conclusion that support is discernably lacking for the Company's plan to build the proposed LNG facility (with the Customer Benefit Guarantee in place) in lieu of the existing propane facilities. The savings associated with retaining the existing propane facilities rather than replacing them with the proposed LNG facility, in net present value terms, would be around $53 million. If the cost associated with the LNG facility turns out to be 25 percent higher than the Company's estimate, the savings would be roughly $136 million (net present value, See Schedule PKC-3c which relies on the Company's response to DR OCA 12-19).

Moreover, under the most cost-effective option, per the SENDOUT run, not only does the Company need capacity with ENGIE, it should also consider a contract with REPSOL to the tune of roughly 36,000 Dth per day. The optimal mix however does not include any supplies on the Dawn to PNGTS path.

Of course, as has been observed multiple times already, I do not agree with the premise that the planning horizon ought to be 20 years. What follows next is a look at the findings when a planning horizon of 10 years is considered.

**Q. Please discuss the analysis that models the Company's pricing forecast, but uses a planning horizon of 10 years, employs a discount rate of 6 percent, uses annualized costs for the Granite Bridge Project, and models the OCA's demand forecast.**

A. Table 4 below summarizes my findings based on the SENDOUT analyses reported by the Company in response to OCA 12-18.

**Table 4: OCA's Demand Forecast with 2018 tax policy changes/Planning Horizon of 10 years/Annualized Costs with Discounting (2021-28)***

| | | | Resource Mix Results (Dth/day) | | | | |
|---|---|---|---|---|---|---|---|
| Planning Scenario | GB LNG | Propane Facilities | Dawn | REPSOL | ENGIE | Total System Cost ($000) | Comparison to Base Case ($000) |
| Base Case | 2 Bcf | No | 0 | 0 | 0 | 774,644 | 21,437 |
| Base Case CBG | 2 Bcf | No | 0 | 0 | 0 | 753,207 | 0 |
| Alternative Case Sensitivity | No | Yes | 0 | 17,670 | 7000 | 701,722 | (51,485)** |

* The OCA relied on the information provided in response to OCA 12-18.f and OCA 14-5 to conduct its analysis. See Schedules PKC-4a and PKC-4b for details.
** With a discount factor of 4 percent, this delta is - $54.6 million.

As is evident from Table 4, even with a reasonable planning horizon of 10 years or so, the Alternative Case Sensitivity Scenario continues to remain more cost-effective relative to the Base Case (to the tune of roughly $51.5 million). If the initial cost associated with the LNG facility escalates 25 percent, the "Alternative Case Sensitivity" Scenario would save $99 million (net present value) for the ratepayers relative to the Company's preferred strategy; *see* Schedule PKC-4c, which is based on Company's response to data request OCA 12-18.f.

Further, as I noted in the discussion of the results associated with the 20-year planning horizon SENDOUT scenario, the optimal portfolio includes REPSOL. It appears that the Company should explore the possibility of about 18,000 Dth per day contract with REPSOL. Also, even under the OCA's forecast scenario, the Company's proposed reliance on ENGIE is still optimal. As in the case of the 20-year planning horizon based SENDOUT analysis, the optimal contract does not include any supplies on the Dawn to PNGTS path.

IVb.3 <u>Additional SENDOUT Runs</u>

**Q. Did you investigate any other demand forecast scenarios?**

A. Yes. I also briefly examined the implications of modeling a demand forecast scenario that was more optimistic than the OCA's scenario discussed above, but one that is still appropriately less optimistic than the Company's projected scenario. The Staff had requested an analysis of such a demand scenario per its data request 5-17.b.ii. Following the Company' supplemental testimony in March 2019, the same forecast scenario (adjusted for the newly granted Unitil franchise in Epping) was subjected to SENDOUT analyses per data requests OCA 12-17, OCA 14-2 and OCA 14-3 to facilitate modeling annualized costs and a reasonable discount rate to reflect ratepayers' time-preference, under planning horizons of ten and twenty years. It is important to highlight that the difference between the OCA's forecast scenario and this additional forecast scenario is roughly 3,000 Dth per day for the terminal years of the planning horizons. One might conclude that the additional run is not fundamentally different from that of the OCA's forecast scenario. That would be an oversimplification. As was pointed out earlier, the OCA's forecast scenario that was analyzed already builds in a reasonable buffer (about 8,000 Dth per day) relative to a more realistic expectation of future load. The additional run further exaggerates that buffer by roughly 25 percent to approximately 11,000 Dth per day for the terminal periods. The additional forecast scenario is a reasonable sensitivity-case to consider, as it reasonably serves as an upward bound on expected loads for the terminal years of the planning horizons of both ten and twenty years.

**Q. Please discuss the SENDOUT findings for the "50% Demand Case" when the Company's pricing forecast was modeled.**

A. Table 5 below reports the findings associated with the analyses modeling 20-years' planning horizon, under the Company's pricing forecast projections.

**Table 5: "50% Demand Case" with Annualized Costs and 6% discount rate and 20-years' planning horizon (discounting applied on 2022-23 to 2038-39)* under Company's Pricing Forecast**

| | | | Resource Mix Results (Dth/day) | | | | |
|---|---|---|---|---|---|---|---|
| Planning Scenario/DR** | GB LNG | Propane Facilities | Dawn | REPSOL | ENGIE | Total System Cost ($000) | Comparison to Base Case ($000) |
| Base Case | 2 Bcf | No | 0 | 0 | 0 | 1,493,776 | 21,038 |
| Base Case CBG | 2 Bcf | Yes | 750 | 0 | 0 | 1,472,738 | 0 |
| Alternative Case Sensitivity | No | Yes | 0 | 38,810 | 7,000 | 1,424,897 | (47,841)** |

* The analysis builds on Company's response to data requests OCA 12-17.e and OCA 14-2.c. See Schedules PKC-5a and PKC-5b.
** With a discount factor of 3 percent, this delta is - $47.7 million.

As is evident from Table 5, it still holds that continuing to rely on the existing propane facilities without building the proposed LNG facility produces significant cost savings for ratepayers, i.e. 48 million dollars (net present basis), over a 20 years' planning horizon. In terms of the resource-mix results, the optimal mix includes about 27,000 Dth per day contract with REPSOL and 7,000 DTh per day contract with ENGIE. Noteworthy though the optimal mix does not include any supplies on the Dawn to PNGTS path.

**Table 6: Staff's "50% Demand Case" with Annualized Costs and 6% discount rate and 10-years' planning horizon (discounting applied on 2021-22 to 2027-28)* under Company's Pricing Forecast**

| | | | Resource Mix Results (Dth/day) | | | | |
|---|---|---|---|---|---|---|---|
| Planning Scenario/DR** | GB LNG | Propane Facilities | Dawn | REPSOL | ENGIE | Total System Cost ($000) | Comparison to Base Case ($000) |
| Base Case | 2 Bcf | No | 0 | 0 | 0 | 782,959 | 20,998 |
| Base Case CBG | 2 Bcf | Yes | 0 | 0 | 0 | 761,961 | 0 |
| Alternative Case Sensitivity | No | Yes | 0 | 20,630 | 7,000 | 712,275 | (49,686)** |

* The analysis builds on Company's response to data requests OCA 12-17 and OCA 14-3. See Schedules PKC-6a and PKC-6b.
** With a discount factor of 3 percent, this delta is - $52,6 million.

As Table 6 above corroborates, when a planning horizon of 10 years is modeled, the results are qualitatively similar to the ones obtained in the case of the OCA's demand forecast scenario. To reiterate, while the Alternative Case (No LNG, but with existing propane facilities intact) is overwhelmingly cost-effective relative to the Company's preferred strategy, even the strategy of not building the LNG facility (irrespective of the size of the LNG tank) as well as retiring the propane facilities appear to be more cost-effective than the Company's preferred strategy. Moreover, based on SENDOUT's Resource-Mix optimization, it is also clear that optimal mix does not include any supplies on the Dawn to PNGTS path. It however includes supplies from ENGIE and REPSOL. The optimal supply from REPSOL is about 21,000 Dth per day.

**Q. Please summarize your findings from the analyses reported in Section IV.**

A. First, when one reasonably accounts for existing ratepayers' interests,[22] even if the Granite Bridge Pipeline turns out to be an important element of EnergyNorth's

[22] As has already been discussed in section IIIc., to represent the existing ratepayers' interests in reasonable fashion, I have relied on the results obtained from the SENDOUT runs that model annualized costs (non-levelized) rather than the levelized costs, a discount rate to reasonably reflect the ratepayers' time-preference, and a planning horizon of 11 years.

supply strategy going forward, the LNG facility as proposed by the Company is not cost-effective. This is so even with the Customer Benefit Guarantee. Irrespective of whether the OCA's forecast scenario is assumed or whether we model the Company's scenario or something in between, the savings associated with persisting with the existing propane facilities rather than building the LNG facility as proposed is significant enough that it cannot be assumed away by arguing that the resiliency benefits (which the Company never estimated in dollar terms) from having the new LNG facility in place rather than continuing with the existing propane facilities outweigh those savings.

To the extent there are benefits to ratepayers arising out of developing an alternative to the Concord Lateral, those benefits accrue via construction of the pipeline. Thus construction of the pipeline was assumed in the SENDOUT runs conducted in this docket.

While there could be other non-monetized net benefits associated with replacing the propane facilities with a large LNG facility, they cannot negate the substantial savings noted in our analysis in this and the previous sections associated with retaining the Company's existing propane facilities in lieu of the LNG facility. At the least, the burden of proof that such benefits may wholly negate the savings discussed above lies with the Company. Nothing in the Company's submissions, and nothing adduced in the discovery conducted to date in this docket, that would justify such a conclusion.

Second, while the Company's request for approval of its proposed contract with ENGIE reasonable, the Company could explore contracting supplies from REPSOL, at least over the next few years, as part of its long-term supply strategy. Indeed, when the interest of ratepayers is reasonably acknowledged, the optimal long-term portfolio supports roughly a 20,000 Dth per day contract with REPSOL. As for the contract with PNGTS, regardless of whether we consider the OCA's demand forecast scenario or the Company's demand forecast scenario, the SENDOUT analyses show that EnergyNorth does not require any supplies on the Dawn to PNGTS path.

**Q. Do you have any comments on the Company's assertion in its supplemental testimony about the benefits accruing to EnergyNorth's customers on the LNG facility stemming from avoided peaking costs?**

A. The Company's historical look at 2013-2018 (as reflected in the Supplemental Testimony, *see* Bates page 068, Line 10 to Bates page 069, Line 04) discusses the benefits associated with avoided costs resulting from the construction of the LNG facility. Those benefits however do not exceed the costs associated with the building of the LNG facility. The company later updated its analysis to include the cost savings associated with the CBG and Dracut capacity costs ( Confidential Attachment OCA TS 1-3.b, Attachment PKC-6), to show the net savings to be positive.

I disagree with that analysis. At the outset, I do not agree that for a forward-looking project like the LNG facility (certainly given its size), it is helpful to look at a historical period to derive conclusions about cost savings for ratepayers. Even if the analysis has some relevance, I disagree with the Company's assertions about the savings associated with CBG and the Dracut capacity costs. First, the CBG is predicated on the Company's MOU with Calpine. Even if we assume that the LNG tank can be emptied fully over winter without incurring any additional cost (which is unlikely to be the case), only 60 percent of the capacity would be available for the benefit of the Company's captive customers. Consequently, the LNG savings (December to February) would not be [redacted] as represented in the aforementioned response to the data request, but reasonably should be estimated to be approximately [redacted].

Second, the savings on account of the Dracut capacity costs should be discounted, as we do not expect that in the initial years of the LNG facility's operations the Company can avoid the capacity costs. Also, even from the SENDOUT runs, it is evident that the Company would have to rely on the supplies from Dracut.

Third, the revenue requirements for the initial five years is not [redacted]. The ratepayers will actually roughly face a cost incidence of [redacted] over the first five years, per the Company's current estimate (based on preliminary scoping) of the initial project cost for the LNG facility (see response to data request PLAN 8-10, Confidential Attachment PLAN 8-10, Attachment PKC-7).

Finally, I expect that the current estimate will be revised upward materially when the LNG storage project is further refined. In view of all of the observations above, the net-savings still remain materially negative even with the adjustments for CBG and capacity cost savings with Dracut.

## V. Concluding Remarks and OCA's Recommendations

**Q. Please briefly discuss how this section is organized.**

A. In this section, I first delve into the issue of bill impact of the primary supply strategies under consideration. This discussion is more in the nature of providing additional information to the Commission. The focus on bill impact (cost per Dth) is indeed an important consideration when deciding whether to approve a new project or not. Finally, I wrap up by providing the OCA's recommendations based on our analyses in this testimony.

**Q. Please briefly discuss how you developed the bill impacts based on the choice of the supply strategies?**

A. We have relied on the analytics provided by the Company in its responses to OCA 13-2, OCA 12-2, and 12-19, as one approach. The analytics there examine the impact of the supply strategies on R3 (Residential heating) customers. We have also used a back-of-the-envelope approach to see how the additional revenue requirement associated with the Granite Bridge projects (pipeline and LNG storage) compares with the current revenue requirement of EnergyNorth (distribution and cost of gas (COG)). Based on the results of the SENDOUT analyses, we have also restricted our examination of the supply strategies to only the Company's preferred strategy and the strategy per the OCA's analyses. To reiterate, those supply strategies are (1) build both the GBP and the LNG facility, while retiring the existing propane facilities, and (2) build only the Granite Bridge Pipeline, while retaining the existing propane facilities, respectively.

**Q. Please explain why you relied on two approaches to get estimates of the bill impacts of the examined supply strategies.**

A. Even if we assume that the actual costs associated with the two Granite Bridge projects pan out to be exactly as projected by the Company, the actual impact on ratepayers would depend on how the presence of those facilities affects the supply portfolio that the Company marshals in reality. Certainly, the SENDOUT optimizations are just theoretical looks. They are not relied on to dictate day-to-day gas-service operations. Not only is weather uncertainly a factor, but so is the reality that the energy procurement professionals rely on contractual obligations that are already in place, available flexibility in day-to-day operations, and human judgement to manage supplies. To get a good projection on the bill impact is therefore not easy. The first approach, relied for estimating the impact on residential customers (R3), uses information from the SENDOUT runs that optimize the supply portfolios. Such a look is reasonable as it provides insight into how all resources can be marshalled optimally, given the SENDOUT input assumptions.[23] The second approach that compares the new revenue requirement (existing revenue requirement *plus* the additional revenue requirement emanating from the Granite Bridge projects) with the existing revenue requirement (with adjustments for presumed growth in gas demand) to measure the bill impacts essentially ignores any cost-based optimization that the Company

[23] The SENDOUT input assumptions and the restrictive nature of the Resource Mix Module restricts the SENDOUT runs to discretely modeling the sizes of the LNG facility and other alternatives. Strictly speaking, SENDOUT analyses do not therefore determine the precise optimal solution.

potentially could apply due to the presence of new facilities. The estimates from the two approaches therefore should be roughly viewed as end-points that create a band, within which the actual bill impact would actually lie. What follows is discussion of the bill impact estimates based on the approach reflected in the Company's Confidential response to OCA 13-2 (Attachment PKC-8).

**Q. Briefly summarize the Company's response to Staff 13-2.**

A. The Company projected that for R3 (residential heating) customers the total annual bill will increase from [redacted] to [redacted], i.e. an increase of [redacted] percent. The existing COG rates were predicated on the Company-filed COG rates for 2018-19. According to the Company, the rates (SENDOUT average cost of served demand beginning 2022-23) effective for its preferred strategy were derived from the SENDOUT run that was part of the supplemental testimony.

**Q. What are your reservations about the Company-derived estimates of the Bill Impacts?**

Two points need to be stressed here. First, as has been amply discussed already, the cost-incidence should be based on annualized costs, not levelized costs, to better capture the actual impact on ratepayers. Second, it is imperative to estimate what the bill impact would be in the initial years the project begins to operate. Rather than comparing the average costs over 2023-2039 to the existing COG rates, the analyses are more helpful if based on the projections specifically for 2022-23 compared to the existing COG rates to see what the immediate impact will be on ratepayers.

**Q. Did you conduct any analysis of your own to estimate the total bill impacts of the Company's preferred supply option? If so, please discuss the findings.**

A. Yes, I conducted my own analysis building upon the worksheet that the Company had furnished in response to data requests OCA 13-2, OCA 12-2, and OCA 12-19.

Focusing on the R3 rates, and by modeling the 2018-19 effective COG rates for summer and winter, and using the annualized cost and served demand for 2022-23, I calculated the bill impacts under both the Company's updated forecast scenario and the OCA's forecast scenario already discussed previously. Under the Company's demand forecast scenario, the Company's preferred supply strategy would increase the average annual bill from [redacted] to [redacted]. Under the OCA's forecast scenario, the annual bill will increase to [redacted]. The respective increases are [redacted]. The annual impact on ratepayers, immediately after the all-inclusive project (LNG + Pipeline) goes operational, is quite significant.

As has already been affirmed, I do not agree with the Company with respect to the preferred supply strategy. A continued reliance on the existing propane facilities sans the construction of the LNG facility, instead produces total bill increases of [redacted] under Company's and OCA's forecast scenarios, respectively. To see how sensitive these impacts are to the cost of the Granite Bridge projects, we also calculated the percentage impacts for cost-overruns of 10, 25 and 50 percent. Under the OCA's forecast scenario, the strategy of retaining the existing propane facilities without building the LNG facility yield total bill impacts in 2021-22 of [redacted] for 10, 25 and 50 percent escalations, respectively. Under the Company's forecast scenario, the bill impacts are [redacted] for 10, 25 and 50 percent escalations, respectively (*see* Schedule PKC-7).

With respect to the Company's preferred strategy, under the OCA's forecast scenario, 10 percent, 25 percent and 50 percent cost-overruns yield bill impacts of [redacted] respectively. Under the Company's forecast scenario, the corresponding bill impacts are [redacted] respectively. As is evident, the Company's preferred strategy could cost R3 customers significantly more, right from the word 'go,' and certainly, if there are significant cost-overruns relative to the Company's cost estimates for the initial build-outs of GBP and the LNG facility.

**Q. Now can you please discuss your back-of-the-envelope estimate for the total bill impact?**

A. Limiting the analysis to the initial year when both the pipeline and the storage become operational, the initial annual revenue requirements emanating from the GBP and LNG facility are approximately $23 million, and $36 million, respectively. With respect to the Company's preferred strategy, the additional revenue requirement is the sum of the two revenue requirements *less* the adjustment for customer benefit guarantee, i.e. approximately $50 million annually. With respect to the more cost-effective strategy per my analyses, the additional revenue requirement in the initial stages emanates only from the construction of the Granite Bridge Pipeline, i.e. $23 million annually. Given how the two projects are timed pursuant to the Company's proposal and accordingly modeled in SENDOUT, the cost estimate associated with the LNG project for 2023 is not necessarily a good reflection of the annual cost-incidence, but the numbers above allows a rough comparison between the strategies that have been compared here.

The other relevant input for this analysis is an estimation of the sum of COG and distribution revenue requirements associated with 2017-18. Roughly, the "total revenue requirement" per the COG filing and distribution rate case around 2018-19 was $155 million.[24] The Company's preferred strategy therefore will increase the revenue requirement initially roughly by 32 percent. The strategy called for in my analyses would increase the revenue requirement approximately by 15 percent. These estimates are predicated on the Company's projections of the initial build-out costs for the two parts of the Granite Bridge Project and the non-levelized costs for the projects for 2022-23.

As should be obvious, the aforementioned estimates do not account for how a change in gas demand would impact the per-therm rates. At the very least, to account for the growth in the demand for gas going forward, the above estimates should be adjusted for the percentage growth in demand between 2018-19 and 2022-23 (roughly 11.4 percent for the Company's forecast, and 6.6 percent per OCA's forecast). Doing so,

[24] Approximately, $82 million for distribution revenue, and $73 million for Cost of Gas.

under the Company's demand forecast scenario, implies that the per-therm rate will increase by 18.5 percent with the Company's preferred supply strategy, and by 3.2 percent with the more cost effective strategy per the OCA's analyses. Under the OCA's demand forecast, the per-therm rate will increase approximately 24 percent with the Company's preferred strategy, and by approximately 7.8 percent under the optimal strategy per the OCA's analysis. Again, as was previously noted, these estimates do not account for any portfolio optimization that would be expected to lower bill impacts.

**Q. Please summarize the findings from the two approaches that the OCA relied on to estimate the rate impact of the Granite Bridge Project.**

A. Based on the discussions above, it is reasonable to assume that the actual bill impact would lie somewhere between the estimates derived from the two approaches, one that is informed by a SENDOUT optimization that entails cost minimization, and the other based on a back-of-the envelope calculation that is at a higher end. In view of that, I expect that the total bill impact, at the outset, even assuming that the project costs for the two parts of the Granite Bridge Project pan out to be exactly same as projected by the Company, will be [redacted] if both the LNG facility and the Granite Bridge Pipeline are pursued while retiring EnergyNorth's existing propane facilities. In contrast, if only the Granite Bridge Pipeline is pursued while retaining the Company's existing propane facilities, the bill impact will be [redacted] per my analyses. The impacts would be greater if there are material escalations in the project's cost.

One aspect of how the rate impact plays out on residential ratepayers that should not be lost in the shuffle is that the Company expects to recover the costs associated with the LNG facility entirely from COG rates. The COG is recovered proportionately more from the residential ratepayers than is distribution revenue. So the impact of the Company's preferred strategy on residential ratepayers could be potentially starker than the analysis here shows.

To be very clear, the estimates derived above are not meant to be precise. They are, however, instructive enough to produce an important takeaway for the Commission's consideration, i.e., that the rate impact of the Company's preferred supply strategy would be significant and substantially more than under the strategy called for in my analyses.

**Q. Please provide the OCA's recommendation on what constitutes a reasonable supply strategy for EnergyNorth going forward.**

A. As stated previously, the OCA finds that the Company has not met the burden of proof of showing that Granite Bridge Pipeline is an integral part of its optimal long-term supply portfolio. Importantly given the focus on the testimony here, even if Granite Bridge Pipeline was determined to be part of the optimal long-term supply portfolio, the OCA concludes that it cannot support the Company's petition to build the LNG storage as proposed. The SENDOUT analyses when subjected to proper interpretation, keeping the ratepayers' interests in mind, do not support such a build-out. The SENDOUT analyses also demonstrate that the contract with PNGTS to enable supplies on the Dawn to PNGTS path is dispensable. The SENDOUT analyses however corroborate that it is reasonable to approve the contract with ENGIE as requested by the Company. The OCA also finds that Company may pursue contractual supplies from REPSOL perhaps to the tune of 15,000-20,000 Dth per day, even if that arrangement is a contract for just three-to-five years. It is possible that supply from REPSOL may be further pursued later, as part of the Company's optimal strategy subsequently determined perhaps in the Company's next Least Cost Integrated Resource Plan (LCIRP), if feasible.

The OCA also submits that the question of pursuing the construction of a LNG facility should be revisited perhaps three-to-five years later depending on how EnergyNorth's ratepayers' demand for gas pans out over the next few years or so. The next LCIRP could provide greater clarity on the viability of building a LNG facility in lieu of the existing propane facilities. The OCA urges the Commission to require EnergyNorth to lay out a clear plan (including a timeline) for retiring its existing propane facilities, while also requiring EnergyNorth to show why building a LNG facility in lieu of its existing propane facilities would be in the interest of ratepayers. The OCA contends that, at the least, a comprehensive analysis of the Company's long-term supply strategy could be expressly tasked for a future Least Cost Integrated Resource Plan from the Company.

**Q. Does this conclude your testimony?**

A. Yes.