Information Request DPU-ANE-2-1

Request:

Refer to the Companies' Petition at 5 and 10 and to Exhibit NG-TJB/JEA-1 (Redacted)(Revised May 16, 2016), at 5, lines 6-7. National Grid estimates that the levelized annual net benefits from 2019 to 2038, under a scenario where the Access Northeast ("ANE") and Northeast Direct ("NED") projects are both put into service, are higher than the levelized annual net benefits from ANE project alone. As National Grid is no longer pursuing both the ANE and NED projects, please:

(a) Confirm that National Grid no longer seeks the Department's approval of the NED Agreements;

(b) Explain whether and why it still makes economic sense for National Grid to pursue the ANE project alone, compared to other alternatives, or some combination of ANE and other alternatives; and

(c) Describe National Grid's process in making this determination.

Response:

(a) Due to Kinder Morgan's decision to terminate plans to move forward with its proposed NED Project, which was announced on April 20th of this year, National Grid filed a Motion to Withdraw its Petitionf or approval of the NED Agreements on April 26, 2016 and the Department granted such Motion on April 27, 2016. Therefore, National Grid is no longer seeking the Department's approval of the NED Agreements.

(b) and (c) National Grid continues to seek approval of the ANE Agreements because the Black & Veatch analysis of the ANE Project alone, after accounting for the costs, still results in projected net-benefits to electric customers in New England of over $1.1 billion per year, and a total net present value of $10.2 billion. Section VI of Exhibit NG-TJB/JEA-1 describes National Grid's consideration of alternatives including responses to the RFP issued on October 13, 2015, energy efficiency, renewables, and large-scale hydro resource imports.

Also, subsequent to National Grid's filing of its initial testimony in this proceeding, and as a result of its coordination and consultation with the Rhode Island Office of Energy Resources and the Rhode Island Division of Public Utilities and Carriers pursuant to the Rhode Island Affordable Clean Energy Security Act, the Company asked Black & Veatch to perform additional quantitative analysis of LNG bids received from GDF Suez and Repsol. While these bids had been determined to be "non-conforming" in terms of satisfying the threshold bid criteria, Black & Veatch agreed to perform the quantitative analysis of these bids using the same Integrated Market Modeling process used to determine the net benefits for electricity customers of ANE Project. The results of this additional quantitative analysis reveal the projected net benefits of the GDF Suez and Repsol LNG bids to be less than 49% and 22%, respectively, of the projected net benefits of the proposed ANE project. Please see Exhibit NEER-2-55 (Highly Sensitive Confidential Information).

As a result of this same coordination and consultation with the Rhode Island Office of Energy Resources and the Rhode Island Division of Public Utilities and Carriers, National Grid also asked Black & Veatch to perform additional analysis to examine the sensitivity of the projected ANE net benefits to potential additions of large scale clean energy resources to the system. Specifically, Black & Veatch was asked to run its economic analysis of the ANE project against two new reference cases. It was requested that the first new reference case assume the existence of a new large-scale hydropower resource, with associated transmission infrastructure, reflective of the 1,090 MW Northern Pass Project bid in response to the multi-state Clean Energy RFP. It was requested that the second new reference case assume the existence of not only a Northern Pass Project, but also the existence of a new large-scale wind resource, with associated transmission infrastructure, reflective of the 1,200 MW Maine Renewable Energy Interconnect Project also proposed in response to the Clean Energy RFP. Black & Veatch performed this requested additional analysis, and the results reveal that the proposed ANE Project alone is still projected to generate significant long-term net benefits for electric consumers across all of the studied reference cases. Please see Exhibit NEER-2-44 (Highly Sensitive Confidential Information).

Information Request DPU-ANE-2-2

Request:

Refer to the Companies' Petition at 9, and Exhibit NG-TJB/JEA-1 (Redacted)(Revised May 16, 2016), at 39-40 and 44-48. Given the references to the economic benefits of the combined NED and ANE projects (over a single pipeline regional solution), please explain whether National Grid plans to update and resubmit the Black & Veatch Report, "Evaluation of Long-term Economic Benefits from Proposed Incremental Infrastructure into New England" in order to demonstrate the economic benefits attributed to the ANE pipeline.

Response:

At this time, Black & Veatch does not plan to resubmit its report. As stated in the report, the standalone development of the ANE Project can provide $1.1 Billion in levelized annual net benefits to New England energy consumers. The calculation of benefits from the Base Case and With ANE Only scenario was done independent of the NED project. Therefore, no update is necessary to the Black & Veatch projected economic benefits attributed to the ANE pipeline.

REDACTED

Information Request DPU-ANE-2-3

Request:

Refer to the Companies' Petition at 14, and Exhibit NG-TJB/JEA-1 (Redacted)(Revised May 16, 2016), at 43.

(a) Provide contract subscription quantities to date as an amount and as a percentage of total firm transportation and storage capacity (900,000 million British thermal units ("MMBtu") per day);

(b) Define "sufficient subscription," and describe how it is distinct from "full subscription";

(c) Confirm that a full subscription of 900,000 MMBtu/day is required to achieve the projected net benefits ($1.1 billion annually) to electric customers in New England for the ANE project; and

(d) Explain the minimum amount of subscriptions needed to ensure that the net benefits of the pipeline would be greater than zero to New England ratepayers.

Response:

a) To date the total subscription amount under Precedent Agreements is currently approximately 519,000 MMBtu/day or 58% subscribed out of the 900,000 MBtu/day including National Grid Massachusetts and Rhode Island electric distribution companies ("EDCs") and Eversource Massachusetts and New Hampshire EDCs.

b) Full subscription would be a situation where the full project volumes of 900,000 MMBtu per day are contracted for under the Precedent Agreements and approved as necessary by the various state regulatory agencies. Sufficient subscription would be at a lesser amount than the 900,000 MMBtu/d, but at an adequate level of contracted for volumes for the Project to continue to move forward. As is described in Exhibit NEER-2-34, the parties to agreements for capacity on the ANE Project recognized that this process has complexities because it is possible that not all EDCs across the ISO-NE region will elect to participate. As a result the Company negotiated contingencies in the Precedent Agreements to allow for less than full subscription of the ANE Project capacity. These situations are fully detailed in the Precedent Agreements and include [redacted] It is important to note that the appropriate regulatory approvals were considered and incorporated that [redacted]

Prepared by or under the supervision of: John E. Allocca

[redacted]

c) Black & Veatch modeled the ANE Project based on the stated capacity of 900,000 MMBtu/day, which is projected to provide $1.1 Billion in levelized annual net benefits to electric customers in New England.

d) The RFP response provided by ANE did not provide alternative configurations of capacity for the ANE Project, and as such, Black & Veatch did not analyze other capacity amounts for the ANE Project, and would not know the minimum amount of subscriptions needed to ensure that net benefits are greater than zero to New England ratepayers.

Information Request DPU-ANE-2-4

Request:

Refer to Exhibit NG-TJB/JEA-1 (Redacted)(Revised May 16, 2016), at 40 and 47. Given that National Grid expected the NED project to significantly "enhance the reliability of both the gas and electric grids in New England by creating a new pipeline path into New England that would further support both the existing Tennessee system in New England as well as each of the other interstate pipelines in the region," please discuss:

(a) The impact of the cancellation of the NED project on the existing gas pipeline system serving New England;

(b) The impact of the cancellation of the NED project on the Companies' ability to reach gas-fired generators; and

(c) The impact of the cancellation of the NED project on the Companies' contract quantities for the ANE project.

Response:

(a) The NED Project would have provided significant benefits to New England including: mitigation of existing pipeline constraints; access to an abundant, inexpensive and reliable source of gas supply; increased gas delivery capacity to a significant share of New England based gas fired generation; and, increased delivery pressure to the region. As a result of cancellation of the NED Project, these benefits will not be realized unless equivalent alternatives are developed.

(b) Notwithstanding the cancellation of the NED project, the remaining ANE Project proposed will provide incremental gas delivery capacity to the majority of gas fired generators in New England.

(c) Cancellation of the NED Project will not impact the Company's contract quantities for the ANE Project.

Information Request DPU-ANE-2-5

Request:

Refer to Exhibit NG-TJB/JEA-1 (Redacted)(Revised May 16, 2016), at 32, lines 12-15, and Eversource's response to information request DPU-EVER 3-3(a) to (d) in NSTAR Electric Company and Western Massachusetts Electric Company, D.P.U. 15-181. Please:

(a) Confirm that no gas-fired generator in New England holds any firm pipeline capacity for its fuel requirements;

(b) If this is not the case, provide a list of the gas-fired electric generators in New England that have signed firm gas transportation contracts;

(c) Provide a list of the gas-fired electric generators that buy interruptible gas supply in the secondary market;

(d) Specify the percentage of gas capacity (by volume) used by generators that is firm versus non-firm based on the average of all current contracts;

(e) For firm and non-firm gas-fired generators, identify the generators with dual-fuel capability; and

(f) Provide all supporting documentation in a workable Excel file with all formulae intact.

Response:

(a) The Company is not aware of any generator that has signed up for incremental pipeline capacity in New England, but there may be some generators served by existing natural gas pipeline capacity to which a power plant is directly connected. In many cases, a generator only maintains firm capacity on the lateral that connects the plant to the mainline of gas transmission line. Although these generators do have firm primary pipeline capacity to their gates, they are still reliant upon the secondary market in New England to acquire gas for their plants. See Attachment DPU-ANE-2-5, Column W, "1st Pipeline Name" for those power plants having a known direct connection to an interstate natural gas pipeline serving New England and that utilize gas as either a primary fuel group or secondary fuel group.

(b) Please see the Company's response to Information Request DPU-ANE-2-6(a).

(c) The Company does not have generator specific information regarding which generators utilize interruptible gas supply in the secondary market because this is confidential contractual information. However, based on contract information reported by the pipelines of firm shippers as addressed in the response to DPU-2-6, it is known that less than five percent of the "Gas Only" power plants hold firm primary mainline capacity on pipelines serving New England.

(d) See the Company's response to Information Request DPU-ANE-2-5(c), above.

(e) Please refer to Attachment DPU-ANE-2-5, Column "S", "All Fuel Types" on the tab entitled "Power Plant Units" , which provides categories of fuel including: Natural Gas, Distillate Fuel Oil, and Waste Heat. Attachment DPU-ANE-2-5 further details the "Primary Fuel Group" (Column T of the Power Plant Units tab) and "Secondary Fuel Group" (Column U of the Power Plant Units tab) for each Power Plant listed in Column A, "Power Plant."

(f) See Attachment DPU-ANE-2-5.

Information Request DPU-ANE-2-6

Request:

Refer to information requests DPU-ANE-2-5, and Eversource's response to information request DPU-EVER 3-4(a) to (g) in D.P.U. 15-181. For each gas-fired generator in New England that has contracted for firm gas transportation service, please provide:

(a) The name of the generator;
(b) The location of each facility;
(c) The megawatts ("MW") of installed capacity of each facility;
(d) The duration of the contract;
(e) The contract quantity;
(f) The contract receipt and delivery points; and
(g) An explanation of whether the number of generators and contract quantities with firm gas transportation contracts has been increasing or decreasing over the last five years; and
(h) All supporting documentation in a working Excel spreadsheet with all formulae intact.

Response:

(a) Column B, Shipper Name, of Attachment DPU-ANE-2-6, provides the names of all non-LDC shippers holding firm mainline capacity on either Algonquin Gas Transmission, LLC or Tennessee Gas Pipeline to serve New England. This list is exclusive of (a) lateral only service that does not provide the shipper with access to firm supplies on mainline capacity, and (b) those firm transportation contracts which may be used only to take natural gas supplies *out of* New England. Attachment DPU-ANE-2-6 also reports specific information on the contract between the shipper having title to the firm pipeline capacity and the Pipeline, including the Contract End Date (Column F), the Contract Maximum Daily Transportation (Column G), and the path of the associated capacity (receipt and delivery points, "Point Name"). The Company does not have information to enable it to determine whether that shipper is a marketer or generator, nor does the Company have access to any confidential contractual arrangements between third parties regarding how non-LDC shippers may utilize their firm capacity, including whether a gas marketer uses its capacity to supply a generator and how those generators and marketers may have utilized their available capacity over the last five years or revised their contractual entitlements.

(b) See Attachment DPU-ANE-2-5, Power Plant Units tab, Column Z, for the location of generator facilities.

(c) See Attachment DPU-ANE-2-5, Power Plant Units tab, Columns H-M for installed capacity at generator facilities.

(d) See Attachment DPU-ANE-2-6, Columns E-F.

(e) See Attachment DPU-ANE-2-6, Column G, for the contract quantity of capacity held by non-LDC shippers on Algonquin Gas Transmission, LLC or Tennessee Gas Pipeline.

(f) See Attachment DPU-ANE-2-6, Column I, for contract quantity of capacity held by non-LDC shippers on Algonquin Gas Transmission, LLC or Tennessee Gas Pipeline.

(g) See the Company's response to Information Request DPU-ANE-2-6(a), above.

(h) See Attachment DPU-ANE-2-6.

Information Request DPU-ANE-2-7

Request:

Refer to Eversource's response to information request DPU-EVER 3-5(a) to (h) in D.P.U. 15-181. For each gas marketer in New England that has contracted for firm gas transportation service and released capacity to gas-fired generators on a firm basis, please provide:

(a) The name of the gas marketer;
(b) The name of the generator the gas marketer supplies;
(c) The location of each facility;
(d) The MW of installed capacity of each facility;
(e) The duration of the contract;
(f) The contract quantity;
(g) The contract receipt and delivery points;
(h) An explanation of whether the number of generators being served by gas marketers and contract quantities with firm gas transportation contracts has been increasing or decreasing over the last five years; and
(i) all supporting documentation in a working Excel spreadsheet with all formulae intact.

Response:

Please see the Company's response to Information Request DPU-ANE-2-6.

REDACTED

Information Request DPU-ANE-2-8

Request:

Refer to Exhibit NG-TJB/JEA-1 (Redacted)(Revised May 16, 2016), at 44, lines 9-12. Please:

(a) Explain the reason(s) that the initial contract quantity may be modified and differ from the final contract quantity;

(b) Indicate the potential range in differences in contract quantities the Companies anticipate; and

(c) If the Companies' final contract quantities differ from the quantities initially proposed, provide examples of how the changes would not create risk for customers.

Response:

(a) Section 3 of the Precedent Agreements discusses potential adjustment of the Company's contract quantities. As described therein, the contract quantity is subject to adjustment to the extent necessary to comply with applicable state law, regulation or order. The contract quantity is also subject to adjustment upon mutual agreement of the parties following notice by Algonquin on or before January 1, 2017 that [redacted]

(b) The Company's contract quantities will not increase absent approval by the Department.. It is difficult to predict the range of potential differences in the contract quantities as it is largely driven by factors beyond the Company's control.

(c) The Company's contract quantities will not increase absent approval by the Department and the Company would not seek approval of an increase unless it believed that the level of risk was appropriate and was supported by a cost/benefits analysis.

Prepared by or under the supervision of: John E. Allocca

Information Request DPU-ANE-2-9

Request:

Refer to Exhibit NG-TJB/JEA-1 (Redacted)(Revised May 16, 2016), at 55, and Investigation by the Department of Public Utilities Into the Means to Add Natural Gas Delivery Capacity to the New England Region, D.P.U. 15-37, at 45 (2015). Given that the Department's filing requirements specified in D.P.U. 15-37 provide that the range of alternative reliable and least-cost resource options "include all energy resources reasonably available in the market that have the potential to address the objective of providing electricity at a reasonable cost and that compare favorably in terms of price and non-price factors," please explain:

(a) Why the request for proposal ("RFP") guidelines were designed to initially exclude electric resource alternatives, such as large-scale hydro power and electric transmission, from consideration in its analysis of the range of alternative options; and

(b) How the Companies' analysis of the RFP responses satisfies the filing requirement that a petitioner provide an analysis of the range of alternative reliable and least-cost resource options.

Response:

(a) and (b)

The Company agrees with the response below as provided by Eversource Energy as Exhibit DPU-EVER-3-7 in D.P.U. 15-181:

> The Companies, along with regulators and policy-makers throughout the region, numerous consultants and ISO-NE, recognize that there is a gas reliability issue and increased gas and electric market price volatility as a result of an existing dependence on natural gas for power generation. According to the ISO-NE 2016 Regional Electricity Outlook, almost half of the region's generating capacity is made up of gas-fired generators and that percentage is expected to increase as 4,200 MW of non-gas generating capacity has been retired or is planned to be retired in the near-term. In addition, ISO-NE estimates that there is 6,000 MW of non-gas generation that is at risk of retirement. This indicates that more than 10,000 MW has retired or will be retiring in the near future and, given the

> most recent forward capacity market auction, natural gas was most often utilized as the replacement fuel. As a result, the Companies' RFP was purposely and specifically focused on identifying options for obtaining needed gas infrastructure for generation to ensure reliability at a reasonable cost. By structuring the RFP in this manner, the Companies were able to identify alternatives and target solutions of a sufficient scale and size to address the longstanding issue of capacity constraints in a meaningful and impactful way. New England requires multiple resources in order to provide diversity in the region, includes hydro-electric power, renewable energy and energy efficiency. All of these alternatives are being considered separately as part of the Clean Energy RFP that was issued on November 12, 2015. Please refer to the response to Information Request DPU-EVER-1-5 for additional information regarding the Clean Energy RFP.

Please refer also to the Company's Response to Information Request DPU-ANE-2-1, parts (b) and (c), and Information Request DPU-ANE-2-26.

Information Request DPU-ANE-2-10

Request:

Refer to Exhibit NG-AEL-3, at 1-2, footnote (c) of the table entitled "Illustrative Capacity Cost Recovery Factor (CCR) & Energy Savings Factor." Please:

(a) Explain whether and how municipalities and co-operatives would benefit directly or indirectly from the firm gas transportation and LNG storage services contracts; and

(b) Explain whether and how the contract costs (fixed and variable transportation charges, storage inventory costs, and administration expenses), would be allocated to and recovered from municipalities and co-ops if the firm gas transportation and LNG storage services contracts would confer benefits to these non-participating entities.

Response:

(a) The entities designated as municipalities and/or co-operatives in the region would benefit. If these entities are vertically integrated, i.e., they own and operate their own gas-fired generation, then the increased access to firm gas transportation and LNG storage would provide these entities with more reliable and liquid gas supplies to serve their facilities to generate power. If these entities purchase their power on the wholesale energy markets, they would realize the benefits of lower electricity costs projected to result from the incremental natural gas transportation and storage infrastructure, as detailed in Exhibit NG-JNC-3.

(b) If the entities were to acquire the pipeline capacity or storage from the EDCs' asset manager, then they would have to pay for that capacity at the then-effective market-driven rate under the Electric Reliability Service Program and be responsible for any associated costs attributable to that capacity. To the extent that the municipalities or co-operatives acquired a portion of the project capacity, they would be allocated their pro-rata share of capacity and be responsible for the corresponding costs. For the purposes of assessing the benefits and costs of the Proposed Agreements presented in Exhibit NG-JNC-3, National Grid and Black & Veatch assumed that municipalities and co-operatives would not enter into long term capacity contracts; the analysis also assumed no offsetting revenue from capacity releases to municipalities and co-operatives. The analysis in NG-JNC-3 finds substantial net benefits for National Grid's customers even with these assumptions.

Prepared by or under the supervision of: Timothy J. Brennan

Information Request DPU-ANE-2-11

Request:

Refer to Exhibit NG-TJB/JEA-1 (Redacted)(Revised May 16, 2016), at 59-60 and 62-65. Please confirm that the Companies completed an analysis (with specific references to the analysis in the filing) that factors in the combined impact of the following items on forecasted winter electric peak demand and retail prices from 2018 to 2035:

(a) Planned incremental pipeline capacity (expected from the Algonquin Incremental Market, Connecticut Expansion, and Atlantic Bridge projects);
(b) Firm LNG import contracts;
(c) Expansion of dual-fuel capable power plants;
(d) ISO-NE's Pay-for-Performance program;
(e) ISO-NE's solar PV load forecast;
(f) Energy efficiency/Demand response; and
(g) Regional clean energy RFPs (new electric transmission capacity).

Response:

a. Black & Veatch included the planned incremental pipeline projects in its analysis, as stated in Exhibit-NG-JNC-3, at 14.

b. Black & Veatch included the known firm LNG import volumes at Everett in its analysis, as stated in Exhibit-NG-JNC-3, at 12.

c. In its analysis, Black & Veatch has included the expansion of dual-fuel capable power generation units in New England.

d. The Pay for Performance program is not explicitly modeled within the production cost model ProMod, which focuses on energy and operating reserve markets. The Pay for Performance model is a capacity payment based performance model where generators receive payments, or pay penalties, for assumed performance under scarcity conditions in the energy market. Without having the benefit of how the Pay for Performance program is performing with respect to generator availability improvement, Black & Veatch used industry average forced outage rates. From a modeling perspective Black & Veatch has assumed that these generators will perform as expected under scarcity conditions

e. Black & Veatch used the 50/50 load forecast from the 2015 ISO New England Capacity, Energy, Loads, and Transmission ("CELT") Report, and the winter and summer peaks are modeled individually by year. This forecast includes adjustments for behind-the-meter solar.

f. Black & Veatch used the 50/50 load forecast from the 2015 ISO New England CELT Report, and the winter and summer peaks are modeled individually by year. This forecast includes adjustments for passive demand response.

g. Black & Veatch has provided additional analysis in Exhibits NEER-2-55 and Attachments NEER 2-55(a) through NEER 2-55(e) (each containing Highly Sensitive Confidential Information) regarding additional sensitivities which include the impact of the regional clean energy RFP and new electric transmission capacity.

Prepared by or under the supervision of: Joseph Neil Copeland

Information Request DPU-ANE-2-12

Request:

Refer to the Companies' response to information request DPU-ANE 2-11. If the Companies answered affirmatively, please describe how the Companies factored each item referenced in DPU information request DPU-ANE-2-11 into the determination/justification of the estimated need, type, size, and timing of its firm transportation and storage services contracts. Provide all supporting documentation for the Companies' analysis in a working Excel spreadsheet with all formulae intact. If the Companies' analysis did not include any factor discussed above, explain why the Companies did not do so.

Response:

Black & Veatch has factored each item referenced in Information Request DPU-ANE-2-11 in its projection of annual levelized electric customer benefits from the ANE Project. As stated in Exhibit NG-JNC-1, Black & Veatch's analysis focused on the impact of the ANE Project on regional natural gas and electric prices and the associated long-term economic benefits to New England consumers. The RFP specified the timing, type, and size of the requested firm transportation and storage services.

Information Request DPU-ANE-2-13

Request:

Refer to Exhibit NG-TJB/JEA-1 (Redacted)(Revised May 16, 2016), at 62. Please provide a table that lists capacity resources (in MW) by fuel type, which have cleared each year in ISO-NE's forward capacity auction. Identify all gas-fired resources with dual-fuel capabilities. Provide this table in a working Excel spreadsheet with all formulae intact.

Response:

Please see Attachment DPU-ANE-2-13 for a table of units that have cleared each year in ISO-NE's forward capacity auction. See also Attachment DPU-ANE-2-5 for identification of dual-fuel capabilities.

Information Request DPU-ANE-2-14

Request:

Refer to Exhibits. NG-PJA-1, at 10-12, and NG-PJA-3, 1-3. Please:

(a) List all the non-price factors that National Grid considered in its evaluation of the ANE Project and how National Grid weighted each non-price factor;

(b) Describe how National Grid weighted each non-price factor and evaluated that factor in its cost-benefit analysis. Provide all supporting documentation for the Companies' analysis in a working Excel spreadsheet with all formulae intact. If the Companies did not perform any analysis, explain why.

(c) Describe how National Grid weighted each non-price factor and evaluated that factor in its alternative resource analysis. Provide all analysis that National Grid conducted. If the Companies did not perform such an analysis, explain why; and

(d) Explain whether the Companies completed a quantitative evaluation and compared any alternative resource options with respect to its individual contribution to achieving the Global Warming Solutions Act greenhouse gas emission reduction goals. Provide all supporting documentation in a working Excel spreadsheet with all formulae intact. If the Companies did not perform such an analysis, explain why.

Response:

a-c. As stated in Exhibit-RWP-1,[1] the purpose of this testimony was to review the RFP responses to determine which were eligible for analysis for evaluation of the long-term economic benefit to electric consumers. As part of the review, Black & Veatch considered both price and non-price requirements relative to the key requirements of the RFP and which were required for conducting the Economic Benefits modeling. These key requirements are summarized in Exhibit-RWP-4. Once a RFP response was determined to have satisfied the key requirements of the RFP, it was then considered for potential Economic Benefits modeling. If the proposal did not satisfy the key requirements then it was set aside as unacceptable for modeling purposes.

[1] On March 3, 2016, the Company filed Exhibits NG-RWP-1through NG-RWP-5 to replace Exhibits NG-PJA-1 through NG-PJA-5. As explained in the Company's filing letter, witness Peter J. Abt is no longer employed by Black & Veatch and Mr. Porter has adopted Mr. Abt's testimony and supporting exhibits.

d. Black & Veatch did not complete a quantitative evaluation or compare any alternative resource options with respect to its individual contribution to achieving the Global Warming Solutions Act greenhouse gas emission reduction goals as this was neither a specific goal nor listed as a requirement in the RFP and consequently was neither an input nor an output of the modeling process.

Information Request DPU-ANE-2-15

Request:

Refer to Exhibit NG-TJB/JEA-1 (Redacted)(Revised May 16, 2016), at 34, lines 10-14. Please identify each existing LNG facility in New England that is currently capable of liquefying domestically produced gas from the Marcellus region during the gas off-peak seasons, and the volumes of gas that could be liquefied at each identified facility using:

(a) Currently existing pipeline capacity;

(b) Currently existing pipeline capacity plus the incremental capacity expected from the Algonquin Incremental Market, Connecticut Expansion, and Atlantic Bridge projects;

(c) Currently existing pipeline capacity plus the incremental capacity expected from the Algonquin Incremental Market, Connecticut Expansion, and Atlantic Bridge projects plus the proposed ANE Project without the proposed Acushnet LNG facility (i.e., incremental firm transportation capacity only); and

(d) Currently existing pipeline capacity plus the incremental capacity expected from the Algonquin Incremental Market, Connecticut Expansion, and Atlantic Bridge projects plus the proposed ANE Project with the Acushnet LNG facility (i.e., incremental liquefaction capacity).

(e) Provide all supporting documentation in a working Excel spreadsheet with all formulae intact.

Response:

a-e. Black & Veatch believes that there are [redacted] existing LNG Facilities in New England that are currently capable of liquefying domestically produced gas from the Marcellus region during the gas off-peak seasons. In the table below, Black & Veatch has provided the liquefaction capacity of each facility.

Existing LNG Facility	Liquefaction Capacity (MMBtu/d)
[redacted]	[redacted]

Prepared by or under the supervision of: Joseph Neil Copeland

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

The volumes of gas that could be liquefied at each facility during the gas off-peak season remains unchanged as sufficient pipeline capacity most likely exists to accommodate the daily maximum liquefaction quantity.

The Acushnet LNG facility will also be capable of liquefying domestically produced gas from the Marcellus region during the gas off-peak season. It is also capable of re-gasifying and delivering the volumes to an interstate pipeline that can serve power generation demand.

Information Request DPU-ANE-2-16

Request:

Refer to Exhibit NG-JNC-3, at 8 and 17. Please explain whether National Grid considered the option of building new LNG peak-shaving gas liquefaction and storage facilities on existing pipelines to serve the electric generation sector. Explain why National Grid chose not to pursue this option in lieu of the ANE project and provide supporting analysis for this decision in a working Excel spreadsheet with all formulae intact.

Response:

In selecting the ANE Project, the Company evaluated the proposals that were submitted in response to its October 23, 2015 RFP and selected the projects that provided the greatest benefit. Although several of the proposals included LNG liquefaction, storage and/or vaporization capability, only the Tennessee and Algonquin proposals included an expansion of the pipeline capacity necessary to deliver gas to generators in New England.

Information Request DPU-ANE-2-17

Request:

Refer to Eversource's response to information request AG-2-19, Att. (g) in D.P.U. 15-181: Assessment of New England's Natural Gas Pipeline Capacity to Satisfy Short and Near-Term Electric Generation Needs: Phase II (2014), Exhibit 2-3, at 20. Please:

(a) Update figures in Exhibit 2-3 using 2016 data and add projections for 2020/21 through 2034/35; and

(b) Refer to Eversource Energy's response to information request AG-2-19, Att. (g), at 46-49. Indicate whether National Grid performed analyses that estimate the potential duration and size of gas supply deficit based on the existing gas pipeline system in New England for the winter periods from 2019/20 to winter 2034/35. If National Grid performed such analyses, provide all supporting documentation in a working Excel spreadsheet with all formulae intact.

Response:

a. Please see Attachment-DPU-ANE-2-17(a) for an updated version of the table referred to as Exhibit 2-3 in Eversource Energy's Attachment AG 2-19(g), at 20.

b. Black & Veatch did not conduct any analysis similar to the referenced analysis that estimates the potential duration and size of gas supply deficit based on existing gas pipeline systems in New England.

Information Request DPU-ANE-2-18

Request:

Refer to National Grid's response to information request DPU-ANE 2-17, and Eversource's response to information request AG-2-19, Att. (g) in D.P.U. 15-181: Assessment of New England's Natural Gas Pipeline Capacity to Satisfy Short and Near-Term Electric Generation Needs: Phase II (2014), at 47, Exhibits 6-12 and 6-13. If National Grid did not perform the analyses referenced in information request DPU-ANE 2-17, please provide the following analyses:

(a) Exhibit 6-12: Duration of Gas Supply Deficit in Days. Please update for Winter 2019/20, Winter 2024/25, Winter 2029/30, and Winter 2034/35; and

(b) Exhibit 6-13: Size of Gas Supply Deficit (1,000 Dekatherms). Please update for Winter 2019/20, Winter 2024/25, Winter 2029/30, and Winter 2034/35.

(c) Provide all supporting documentation in a working Excel spreadsheet with all formulae intact.

Response:

As stated in the Company's response to Information Request DPU-ANE-2-17, Black & Veatch did not perform analysis similar to what is referenced in Eversource Energy's Attachment AG 2-19(g), Tables Exhibit 6-12 and 6-13. Black & Veatch's analysis focuses on the impact of the ANE Project on regional natural gas and electric prices and the associated long-term economic benefits to New England consumers. New England's projected firm LDC gas demand growth and the increasing dependence on gas-fired generation support the conclusion that the gas supply deficits are expected to grow which supports the development of the ANE Project.

Information Request DPU-ANE-2-19

Request:

Refer to Eversource Energy's response to information request AG-2-19, Att. (g) in D.P.U. 15-181: Assessment of New England's Natural Gas Pipeline Capacity to Satisfy Short and Near-Term Electric Generation Needs: Phase II (2014), at 48-49, Exhibits 6-14 – 6-16. Please provide analyses comparable to those provided in Exhibits 6-15 and 6-16, including fixed and variable costs for Winter 2019/20, for the following scenarios:

(a) The ANE Project;
(b) Increasing LNG imports;
(c) Electric distribution companies purchasing LNG liquefaction facilities and natural gas storage dedicated to the generation of electricity;
(d) Expanding dual-fuel capability;
(e) Enhancing energy efficiency and demand-side management programs;
(f) Adding new electric transmission; and
(g) Large-scale hydropower contracts.
(h) Provide all supporting documentation in a working Excel spreadsheet with all formulae intact.

Response:

a-b. Black & Veatch's analysis focuses on the impact of the ANE project on regional natural gas and electric prices and the associated long-term economic benefits to New England consumers. Black & Veatch did not conduct cost analysis similar to those referenced in Eversource Energy's Attachment AG 2-19 (g), Exhibits 6-15 and 6-16; however, please see Attachment-AG-1-46(a) Confidential for the annual costs related to the ANE, Repsol and GDF Suez RFP responses.

c-g. Black & Veatch did not conduct additional cost analysis associated with the scenarios listed.

Information Request DPU-ANE-2-20

Request:

Refer to National Grid's response to information DPU-ANE 2-19 and Eversource's request AG 2-19, Att. (g) in D.P.U. 15-181: Assessment of New England's Natural Gas Pipeline Capacity to Satisfy Short and Near-Term Electric Generation Needs: Phase II (2014), at 48. For each scenario referenced in information request DPU-ANE 2-19, please provide an analysis of the fixed and variable costs ($/Dth) for Winter 2029/30, including an updated Exhibit 6-15. Please include an explanation of how the duration and size of gas supply affect the cost of each scenario. Provide all supporting documentation in a working Excel spreadsheet with all formulae intact.

Response:

Black & Veatch's analysis focuses on the impact of the ANE Project on regional natural gas and electric prices and the associated long-term economic benefits to New England consumers. New England's projected firm LDC gas demand growth and the increasing dependence on gas-fired generation support the conclusion that the gas supply deficits are expected to grow which would make the ANE Project more economical. As stated in the Company's response to Information Request DPU-ANE-2-19, Black & Veatch did not perform cost analysis similar to what is referenced in Eversource Energy's Attachment AG 2-19(g), Exhibit 6-15.

Information Request DPU-ANE-2-21

Request:

Please identify and explain in complete detail all cost components that are included in the estimated cost of each segment/facility of the ANE Project. Please identify any segment or facility for which the final construction cost would not be subject to Federal Energy Regulatory Commission ("FERC") oversight. Provide all supporting documentation in a working Excel spreadsheet with all formulae intact.

Response:

All cost components of the ANE Project are subject to FERC oversight and, in accordance with FERC practice and policy will be reviewed to determine reasonableness and prudence. Please refer to Exhibits NEER-2-9, Attachment NEER-2-9-1 and Attachment NEER-2-9-2 (all Highly Sensitive Confidential Information) for project cost information.

Information Request DPU-ANE-2-22

Request:

Refer to the prefiled Joint Testimony of Timothy J. Brennan and John E. Allocca at 2 and the prefiled Testimony of Carol S. White at 8. Please discuss whether the Companies evaluated the ability of electric demand response to provide demand reductions sufficient to offset the cost of the highest priced hours during winter months.

Response:

The Company has considered the potential for a demand response program to provide demand reductions sufficient to offset the cost of the highest priced hours during winter months. As noted on page 9 of Ms. White's testimony, 0.5 – 2.0 BCF is substantially larger than National Grid's already aggressive Massachusetts energy efficiency programs. 0.5 BCF is roughly equivalent to 2,500 MW.

Currently, ISO-NE's active demand-resource programs include real-time demand response resources and real-time emergency generation resources (http://www.iso-ne.com/markets-operations/markets/demand-resources/about), which can be activated within 30 minutes when needed to reduce demand. These programs have a total of 223.5 MW enrolled in SEMA, WCMA, and NEMA combined.[1]

The amount of demand response needed to offset the equivalent of 2,500 MW is 11 times greater than the amount already enrolled in ISO-NE's active demand response programs. Adding this magnitude of additional demand response is not feasible.

[1] ISO-NE: Demand Resource Asset Enrolled MWs by Demand Resource Type and Load Zone, as of 6/1/2016: http://www.iso-ne.com/static-assets/documents/2016/05/a01_intro_drwg_mtg_05_25_2016.pptx

Information Request DPU-ANE-2-23

Request:

Refer to the prefiled testimony of Joint Testimony of Timothy J. Brennan and John E. Allocca at 61. Please provide the average projected capacity factor for offshore wind turbines located off the Massachusetts coast (1) over the course of the year, and (2) during winter months.

Response:

The Company does not have such projected capacity factors, but found the following information available from the National Renewable Energy Laboratory:

> The U.S. Department of Energy's (DOE) National Renewable Energy Laboratory (NREL), under an interagency agreement with the Bureau of Ocean Energy Management (BOEM), is providing technical assistance to identify and delineate leasing areas for offshore wind energy development within the Atlantic Coast Wind Energy Areas (WEAs) established by BOEM. This report focuses on NREL's development of three delineated leasing area options for the Massachusetts (MA) WEA and the technical evaluation of these leasing areas. …
>
> 5.4 Capacity Factor after Wake Losses
>
> The gross capacity factor is the average energy output (before any losses outside the turbine itself are considered) as a percentage of the maximum possible energy output if the turbines were operating continuously at their rated power output, which is 5 MW per turbine for this analysis. For each delineation option, the gross capacity factor was calculated using the Open Wind analysis tool, and methods and layouts described in Section 5.1 and Section 5.2. Table 5, Table 6, and Table 7 provide the gross capacity factors for all of the leasing areas and delineation options after wake losses are subtracted. These capacity factors after wake losses are estimated to be in the range of 45% to 49%, depending on the leasing areas and the turbine layout. The capacity factors generally range about 1% lower in the western leasing areas. Furthermore,

the capacity factors reported in this analysis should not be confused with the net capacity factor (NCF), which is based on actual power delivered on shore and would account for such things as electrical losses in transmitting the power to shore, blade soiling, and other operating inefficiencies. NCF values would likely be nearer to 40% as estimated by some of the RFI and Call nominations shown in Table 1 and Table 2….[1]

[1] Musial, W., Parker, Z, Fields, J., Scott, G., Elliott, D. and Draxl, C., "Assessment of Offshore Wind Energy Leasing Areas for the BOEM Massachusetts Wind Energy Area" (December 2013) (http://www.nrel.gov/docs/fy14osti/60942.pdf).

Information Request DPU-ANE-2-24

Request:

Refer to the prefiled Joint Testimony of Timothy J. Brennan and John E. Allocca at 61. Please provide the generation capacity and average capacity factor for wind plants located in Maine (1) over the course of the year, and (2) during winter months.

Response:

Black & Veatch has provided the nameplate generation capacity for wind plants in Maine, the average capacity factor, and the average capacity factor during the winter months of December through March.

Nameplate Capacity (MW)	Average Capacity Factor (%)	Average Winter Capacity Factor (%)
[redacted]		

Information Request DPU-ANE-2-25

Request:

Refer to the Joint Testimony of Timothy J. Brennan and John E. Allocca at 61. Please provide the generation capacity for wind plants proposed in Maine (1) over the course of the year, and (2) during winter months.

Response:

Black & Veatch has provided in Attachment DPU-ANE-2-25 (Highly Sensitive Confidential Information), the projected nameplate wind capacity in Maine used in the analysis, assumed capacity factors over the year and during the December through March winter months.

REDACTED

Column	A	B	C	D
Line #	**Year**	**Nameplate Capacity (MW)**	**Annual Average Capacity Factor**	**Average Winter Capacity Factor**
1	2018	[redacted]	[redacted]	[redacted]
2	2019	[redacted]	[redacted]	[redacted]
3	2020	[redacted]	[redacted]	[redacted]
4	2021	[redacted]	[redacted]	[redacted]
5	2022	[redacted]	[redacted]	[redacted]
6	2023	[redacted]	[redacted]	[redacted]
7	2024	[redacted]	[redacted]	[redacted]
8	2025	[redacted]	[redacted]	[redacted]
9	2026	[redacted]	[redacted]	[redacted]
10	2027	[redacted]	[redacted]	[redacted]
11	2028	[redacted]	[redacted]	[redacted]
12	2029	[redacted]	[redacted]	[redacted]
13	2030	[redacted]	[redacted]	[redacted]
14	2031	[redacted]	[redacted]	[redacted]
15	2032	[redacted]	[redacted]	[redacted]
16	2033	[redacted]	[redacted]	[redacted]
17	2034	[redacted]	[redacted]	[redacted]
18	2035	[redacted]	[redacted]	[redacted]
19	2036	[redacted]	[redacted]	[redacted]
20	2037	[redacted]	[redacted]	[redacted]
21	2038	[redacted]	[redacted]	[redacted]
22	2039	[redacted]	[redacted]	[redacted]
23	2040	[redacted]	[redacted]	[redacted]

Information Request DPU-ANE-2-26

Request:

Refer to the prefiled Joint Testimony of Timothy J. Brennan and John E. Allocca at 60-65. Please explain whether the Companies considered a portfolio approach to meeting winter natural gas capacity constraints, including but not limited to contracting for a lesser amount of gas capacity, and increasing wind, solar, hydroelectric resources, demand response, energy efficiency, and distributed generation. If the Companies did not consider such an approach, explain why not.

Response:

Please refer to Exhibit DPU-ANE-2-1 for information on the Company's consideration of the ability of such alternative resources to provide a complete solution. Exhibit DPU-ANE-2-1 also provides information on the additional consideration of the ANE Project benefits when it is assumed to be added to reference cases including (1) a portfolio of such resources at their currently projected levels and (2) portfolios including significant additional levels of hydroelectric and wind resources.

The Company also considered the results of the analysis of pipeline capacity needs under various scenarios and potential resource portfolios performed by Synapse Energy Economics, Inc. ("Synapse"). In January 2015, Synapse released its "Massachusetts Low Gas Demand Analysis: Final Report, Prepared for the Massachusetts Department of Energy Resources" (the "Synapse Report").[1]

As stated in the Synapse Report,

> DOER retained Synapse Energy Economics (Synapse) to utilize current forecasts of natural gas and electric power under a range of scenarios, taking into consideration environmental, reliability and cost answering two key questions: What is the current demand for and capacity to supply natural gas in Massachusetts? If all technologically and economically feasible alternative energy

[1] A copy of the Synapse Report can be found at: http://www.synapse-energy.com/sites/default/files/Massachusetts%20Low%20Demand%20Final%20Report.pdf

> resources are utilized, is any additional natural gas infrastructure needed, and if so, how much?"

(Synapse Report at 2).

Synapse reported the following results from its analysis:

> The amount of pipeline required differs based on scenario assumptions … Year 2020 pipeline additions range from 25 billion Btu per peak hour to 33 billion Btu per peak hour (0.6 billion cubic feet (Bcf) per day to 0.8 Bcf per day). Year 2030 pipeline additions range from 25 billion Btu per peak hour to 38 billion Btu per peak hour (0.6 Bcf to 0.9 Bcf per day).

(Synapse Report at 3).

The results confirmed that even with a portfolio utilizing of "all technologically and economically feasible alternative energy resources," significant additional pipeline capacity, consistent with the size of the proposed ANE Project, is needed just to satisfy the needs of Massachusetts.

Information Request DPU-ANE-2-27

Request:

Refer to the prefiled Joint Testimony of Timothy J. Brennan and John E. Allocca at 30-32.

(a) Please explain whether the proposed Acushnet storage facility, in isolation, has the ability to provide natural gas service to electric generators for winter months to alleviate gas capacity constraints and limit high gas prices;

(b) If the answer to (a) is negative, please specify the minimum amount and location of incremental natural gas transmission capacity that would be required on the Algonquin system to enable the Acushnet storage facility to provide reliable natural gas service to electric generators for winter months;

(c) Please describe in complete detail any other challenges, including price, associated with building only the Acushnet storage facility to provide natural gas service to electric generators for winter months; and

(d) Please discuss whether the Companies considered building only a liquefied natural gas ("LNG") storage facility as an option and, if so, explain the Companies' reasoning for not selecting this option. If no, explain why not.

Response:

(a-d). The ANE Project is an integrated project and requires the delivery capacity of the transportation service in order to deliver the LNG to the 4 aggregation areas. The ANE Project was designed as a whole, as opposed to individual pieces, in order to achieve deliverability to the greatest number of plants and to provide the flexibility that generators require, while also providing that the ANE Project can be built at a reasonable cost. Any separation of services, including the Acushnet storage facility, would erode the project benefits substantially by reducing: 1) the number of generators that the ANE Project could reach; 2) the flexibility offered as it would be available on relatively few days; and 3) the overall reliability and cost benefits to electric customers.

Information Request DPU-ANE-2-28

Request:

Refer to the prefiled Joint Testimony of Timothy J. Brennan and John E. Allocca at 12-16. Please evaluate the impacts of the ISO-NE Winter Reliability Program and the ISO-NE Pay for Performance Program on the need for incremental pipeline capacity.

Response:

ISO-NE Pay for Performance model is a capacity payment based performance model where generators receive payments, or pay penalties, for assumed performance under scarcity conditions in the energy market. Without having the benefit of how the ISO-NE Pay for Performance program is performing with respect to generator availability improvement, Black & Veatch used industry average forced outage rate for its analysis. From a modeling perspective, Black & Veatch has assumed that these generators will perform as expected under scarcity conditions. The Pay for Performance rules in the ISO-NE Winter Reliability Program could potentially encourage gas generators to seek firm supplies during peak winter periods while also being more favorable the most efficient and flexible new entry resource types such as new gas-fired generating resources. The region has seen significant new entry of gas fired resources in recent forward capacity market auctions, and approximately two-thirds of proposed new capacity in the ISO-NE interconnection queue are also gas fired resources. This additional new entry of gas-fired capacity will only increase the need for incremental pipeline capacity.

Due to the upcoming phase out of ISO-NE's Winter Reliability program, Black & Veatch did not make any assumptions from ISO-NE's Winter Reliability program in the analysis.

Information Request DPU-ANE-2-29

Request:

Refer to the prefiled Joint Testimony of Timothy J. Brennan and John E. Allocca at 54-56.

(a) Please explain in detail the rationale for the Companies' selection of 500,000 MMBtu/day as a minimum and 2,000,000 MMBtu/day as a maximum energy delivery for RFP responses;

(b) Please explain how National Grid determined that it needed a minimum of 500,000 MMBtu/day of incremental infrastructure to provide relief of electric reliability and retail price volatility concerns; and

(c) Please discuss whether electric system reliability is at risk in the absence of the ANE Project.

Response:

(a) Please see the Company's Exhibits NEER-1-42 and NEER-2-47.

(b) Please see the Company's Exhibits NEER-1-42 and NEER-2-47.

(c) Please see the Company's Exhibit NEER-1-32.

Information Request DPU-ANE-2-30

Request:

Refer to the prefiled Joint Testimony of Timothy J. Brennan and John E. Allocca at 64. Please identify the timing and duration of winter wholesale market supply scarcity or shortage events over the last five years and describe ISO-NE's response.

Response:

As noted by Eversource Energy in Exhibit DPU-EVER-4-13 filed in D.P.U. 15-181, the current forward capacity market design uses the term "shortage event" to define periods when non-demand resources' availability performances are assessed. Scarcity event will replace the shortage event when new pay for performance ("PFP") rules become effective in June 2018. These terms are defined differently, resource performance during these periods is calculated differently, and the monetary consequences are different.

There has been one shortage event over the last five years and by market design there have been no actual scarcity events to date. The shortage event occurred on Saturday, December 14, 2013 from 4:50 PM to 6:15 PM for a total of 85 minutes.

For planning purposes and to allow participants to get a sense as to how the new PFP rules may impact them, ISO-NE, using historical data, has estimated when scarcity events would have occurred in the past. ISO-NE has provided this information in a series of data releases. Links to these reports follow. Please note that there was an earlier report covering a portion of the report included in the first link below, but the earlier report is not provided because it is redundant. Please also see D.P.U. 15-181, Exhibit Attachment DPU-EVER-4-13 for Winter Period system events identified in the data summarized below. Winter Periods are defined as November through the following March (for overlapping periods the most recent report data was used).

ISO-NE Data Releases:

October 2006 through April 2014 http://www.iso-ne.com/static-assets/documents/markets/othrmkts_data/fcm/doc/opr_reserve_deficiency_info_hist_data_updated_5_21_2014.zip

June 2012 through April 2015 http://www.iso-ne.com/static-assets/documents/2015/06/opr_reserve_deficiency_info_hist_data_udpated_6_02_2015.zip

May 2015 through April 13, 2016
http://www.iso-ne.com/static-assets/documents/2015/12/rcpf_event_data_from_may_2015.xlsx

Information Request DPU-ANE-2-31

Request:

Refer to Exh. NG-JNC-3, at 11. Please identify the proportion of electric energy in New England generated by natural gas, and the associated capacity of natural gas power plants, in the New England Region for each calendar year from 2011 to 2016.

Response:

Please see Attachment DPU-ANE-2-31(a). Black & Veatch has provided the annual gas generation and total generation as reported by ISO-New England and the gas capacity from ISO-NE CELT Reports. The 2016 calendar year generation data is through May 31, 2016.

Column	A	B	C	D	E
Line #	**Year**	**Gas Generation (MWh)/1**	**Total Generation (MWh)/1**	**Proportion of Gas Generation**	**Gas Capacity (MW)/2**
1	2011	61,911,971	120,608,398	51%	13,016
2	2012	60,602,987	116,942,274	52%	13,618
3	2013	50,635,909	112,040,637	45%	13,599
4	2014	46,606,001	108,357,468	43%	13,462
5	2015	52,366,112	107,916,822	49%	13,515
6	2016	19,555,340	42,493,091	46%	13,580

1/ Source: ISO-NE Daily Generation by Fuel Type
2/ Source: ISO-NE CELT Reports

Information Request DPU-ANE-2-32

Request:

Refer to the prefiled Joint Testimony of Timothy J. Brennan and John E. Allocca at 30-32. Please discuss the impacts of increased dependence on a single type of fuel on electric system reliability and market pricing.

Response:

The Company agrees with the response below as provided by Eversource Energy in Exhibit DPU-EVER-4-15 filed in D.P.U. 15-181:

> Dependence on a single type of fuel affects reliability if access to the fuel becomes physically constrained to the point where the quantity of resources unable to get the fuel causes operating constraints because there are not sufficient alternative fuel-sourced resources available. So dependence on a single fuel source is not necessarily detrimental, so long as physical access to the fuel exists. Correcting the gas deficiency in New England should be a priority, but diversity is also needed. Developing other sources like large hydro and renewables should also be pursued.

Prepared by or under the supervision of: Timothy J. Brennan

Information Request DPU-ANE-2-33

Request:

Refer to Exh. NG-JNC-3, at 22-24. Please identify the proportion of electric energy that would be generated by natural gas in New England after each phase of the ANE Project becomes operational.

Response:

Please see Attachment DPU-ANE-2-33(a) (Highly Sensitive Confidential Information), for the estimated proportion of electric energy that would be generated by natural gas in New England during the 2018-2021 time period, when each phase of the ANE Project becomes operational.

REDACTED

Column	A	B	C	D
Line #	**Year**	**Gas Generation (MWh)**	**Total Generation (MWh)**	**Proportion of Gas Generation**
1	2018	[redacted]		
2	2019			
3	2020			
4	2021			

Information Request DPU-ANE-2-34

Request:

Refer to the prefiled Joint Testimony of Timothy J. Brennan and John E. Allocca at 25-28. Please describe how National Grid expects to utilize the ANE Project during non-peak gas demand periods.

Response:

Please see Exhibit NG-TJB/JEA-6 for a copy of the Electric Reliability Service Program ("ESRP"). As described in the ESRP the EDCs, through the use of a Capacity Manager, will make the ANE Project capacity available to the generators and the general market as described in Figure 1. The intent of the ESRP is to give the generators multiple opportunities, prior to the month of flow, to secure pipeline and storage capacity to meet electric demand using a lower cost natural gas supply. The ESRP describes when and how the capacity will be first made available to the generators to satisfy electricity demand and then made available to all other natural gas demand markets once electric generation needs are met.

Information Request DPU-ANE-2-35

Request:

Refer to the prefiled Joint Testimony of Timothy J. Brennan and John E. Allocca at 30-32. Please describe the typical utilization of other regional natural gas pipelines during non-peak gas demand periods.

Response:

Typically, the utilization of the regional natural gas pipelines in New England falls during non-peak gas demand periods when the demand profile shifts from space heating to power generation and the capacity reserved by the LDCs becomes more available for the generators and large industrial facilities to utilize natural gas from the secondary market. The lowest utilization rates typically occur during the "shoulder months" (April, May and October) when temperatures fall within a range that does not require space heating or cooling. Utilization rates increase during the "cooling season" (June through September) when natural gas fired power generation increases to meet those regional requirements. The type of utilization is most important, while the overall utilization of the pipelines may drop as LNG and Canadian offshore supplies diminish with prices. The "West to East" utilization will be higher as the gas fired power generation fleet seeks access to the relatively less expensive gas at the West end of the pipelines which connects with Marcellus production areas.

Information Request DPU-ANE-2-36

Request:

Refer to Information Request DPU-GRID 4-14. Please discuss whether the ANE Project could result in excess regional natural gas capacity that could be used for LNG exports.

Response:

Please see Exhibit NEER-2-78.

Prepared by or under the supervision of: John E. Allocca

Information Request DPU-ANE-2-37

Request:

Refer to Exh. NG-JNC-3, at 22-25. Please discuss whether National Grid or Black & Veatch has evaluated the impact of other electric generators (i.e., non gas-fired generators) on wholesale electric price reduction resulting from additional natural gas capacity provided by the ANE Project, including nuclear and renewable units. If the answer is no, provide an evaluation of the impact of wholesale electric price reduction or displacement of other electric generators using current market conditions.

Response:

Black & Veatch has provided the locational marginal pricing ("LMP") electric prices from the Base Case and With ANE Only case in Attachment NEER-1-1(a) (Highly Sensitive Confidential Information). The LMP electric price impact between the Base Case and With ANE Only case represent the price impact for all gas and non-gas-fired generators.

Information Request DPU-ANE-2-38

Request:

Refer to the prefiled Joint Testimony of Timothy J. Brennan and John E. Allocca at 70-72. Please discuss the approval process for the Energy Reliability Service ("ERS") rate schedule at ("FERC") and provide the status of the petition.

Response:

The ERS Rate Schedule will be filed with the FERC 7(c) Certificate application, which has not yet occurred. Provided that the ANE Project is approved by FERC and placed into service, the ERS Rate Schedule will go into effect contemporaneously with the in-service date of the ANE Project.

Information Request DPU-ANE-2-39

Request:

Refer to the prefiled Joint Testimony of Timothy J. Brennan and John E. Allocca at 70-72. If FERC issues a certificate of public convenience for the ANE Project but does not approve the ERS rate schedule, please explain and quantify the impact on the net benefits to electric ratepayers that National Grid estimates is attributable to the ANE Project.

Response:

Please see Exhibit NEER-1-47. In the absence of the FERC approval of the ERS rate schedule the Company cannot forecast the price that non-generators will be willing to pay for the released capacity or the quantity of capacity that would then not be available to the generators. Without knowing these two factors the Company cannot quantify the impact on the net benefits to electric customers.

Information Request DPU-ANE-2-40

Request:

Refer to the prefiled Joint Testimony of Timothy J. Brennan and John E. Allocca at 41. Please discuss whether there are other mechanisms to demonstrate a "market need" for incremental capacity to obtain FERC approval of an application for a Certificate of Public Convenience and Necessity.

Response:

Please see Exhibit NEER-2-33.