The Narragansett Electric Company

d/b/a National Grid (Interstate Reliability Project)

RIPUC Dkt. No. 4360

Supplemental and Rebuttal

Testimony of

Judah L. Rose

February 7, 2013

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Judah Rose and I am employed by ICF Resources, LLC, a subsidiary of ICF International ("ICF"). My business address is 9300 Lee Highway, Fairfax, VA 22031.

Q. Have you previously testified in this proceeding?

A. Yes. I filed testimony in this proceeding on November 21, 2012.

Q. What is ICF's role in this proceeding?

A. ICF was retained by National Grid and Northeast Utilities ("NU") to provide an assessment of the potential for alternative resources, on both the supply and demand side (i.e., non-transmission alternatives or "NTAs"), to displace or defer the need for the Interstate Reliability Project ("Interstate").

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

A. I am testifying on behalf of National Grid.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to supplement my earlier direct testimony and to respond to the testimony of Gregory Booth, filed on January 17, 2013.

Q. How is your testimony organized?

A. My testimony is organized into two sections. The first section contains supplemental testimony, and the second section contains rebuttal testimony.

II. SUPPLEMENTAL TESTIMONY

II.1 Introduction

Q. Why are you supplementing your testimony?

A. In my direct testimony, I stated[1]:

> *Recently, it was brought to my attention that a few of the transmission line ratings used in the ICF Report were inaccurate. I am updating my analysis to incorporate the correct ratings. These line rating changes are not anticipated to alter ICF's conclusions, however I will provide the revised data when I have completed this additional analysis.*

Q. Where were these lines whose ratings were revised?

A. In the Greater Rhode Island sub-area.

Q. What were the changes?

A. It is my understanding that the LTE (Long-Term Emergency) ratings for three 115kV lines were increased. These increases are due to terminal equipment upgrades, removal of a relay setting limitation, and correction of a line sag limitation.

Q. What is the analysis of NTAs conducted by ICF and how might higher line ratings affect the results?

A. There were several steps in the ICF analysis:

- **Confirmation of ISO New England (ISO-NE) results in the Absence of Interstate and NTAs –** The first step was to confirm the ISO- NE findings of violations in the

[1] Page 4, Rose, November 21, 2012.

absence of Interstate and NTAs. All else equal, higher line ratings lower the likelihood of violations.

- **Estimation of the Critical Load Level (CLL) –** The second step was to estimate the CLL. The CLL analysis involves identifying a load reduction that just solves the thermal violations, and thus the load level at which the identified thermal violations begin to occur. Higher line ratings raise the CLL, all else equal.
- **Comparison of Achievable Passive Demand Resources (Passive DR) with the Amount Required to Reach the CLL –** ICF estimated the achievable Passive DR and determined whether the resulting load reduction was enough to reach the CLL. Higher line ratings reduce the amount of Passive DR required to reach the CLL.
- **Determination of Whether Passive DR can be Supplemented by Active DR –** In the event that Passive DR is not enough to get to the CLL, ICF estimated the amount of incremental Active DR required and determined whether this was feasible. Higher line ratings can lower the amount of Active DR required to achieve a demand only NTA, all else equal.
- **Creation of a Combination NTA –** A Combination NTA was created with both Passive DR and new central station generating capacity from the Interconnection Queue.
- **Estimation of CLL for Combined NTA –** ICF estimated the CLL assuming the generation capacity in the Combination NTA was in place. Higher line rating would raise the CLL.
- **Comparison of Achievable Passive Demand Reductions with the Amount Required to Reach the Estimated CLL Assuming Combination NTA Generation in Place –**

ICF determined whether load reductions from achievable Passive DR was enough to reach CLL associated with the Combination NTA generation supply. Higher line ratings reduce the amount of Passive DR required to reach the CLL.

- **Determination of Whether the Combination NTA can be Supplemented by Active DR –** In the event that the Combination NTA is not sufficient to resolve all violations, ICF estimated the amount of incremental Active DR required and determined whether this was feasible. Higher line ratings can lower the amount of Active DR required to achieve a Combination NTA and make it less costly, all else equal.
- **Estimate the Costs of Combination NTA plus Incremental Active DR -** Higher line ratings can lower the amount of required Active DR, and lower costs.

II.2 Revised Estimate of Violations

Q. Did ICF revise its estimate of the number of violations that would occur in the absence of the Interstate to account for these line rating changes?

A. Yes. The number of thermal violations and overloaded elements in southern New England (SNE) in the revised analysis is shown in the table below.

Year	# of Thermal Violations	Overloaded System Elements – Revised Analysis
2015	192	19
2020	5,919	52

Q. How does this revised estimate of the number of violations in SNE compare to the previous estimate?

A. These revised results are very similar to the previous results.

Q. Were there also violations in Rhode Island in the revised analysis?

A. Yes. The number of thermal violations and overloaded elements in Rhode Island in the revised analysis is shown in the table below.

Year	# of Thermal Violations	Overloaded System Elements – Revised Analysis
2015	20	4
2020	33	11

Q. How does this revised estimate for Rhode Island compare to the number of violations in the previous estimate?

A. The number of violations is less than in the previous estimate, though the number of overloaded elements is similar.

Q. Are your conclusions the same?

A. Yes. ICF continues to find a large number of thermal violations spread across numerous locations in SNE. Violations also remain in Rhode Island. Thus, we continue to conclude that due to the number and locations of thermal violations, either Interstate or a NTA is needed and that a NTA solution would likely need to be dispersed across all of SNE including in Rhode Island.

II.3 Revised CLL Estimate

Q. Did ICF revise its estimate of the Critical Load Level (CLL)?

A. Yes, for Rhode Island. The process ICF followed started with ICF reviewing the original CLL analysis presented in the ICF report to determine if the adjustment in transmission line ratings would significantly affect the CLL values. ICF found that only the Rhode

Island CLL values would be affected. Due to the location of the lines in question, there would be little or no impact on the CLL values for Eastern New England and Western New England. Therefore ICF did not revise its CLL estimates for the rest of SNE. Thus, the change in the SNE CLL equals the change in the Rhode Island CLL.

Q. What does ICF's revised CLL analysis for 2015 indicate for SNE?

A. ICF's revised estimate of the CLL for SNE for 2015 is 20,130 MW, which is 2,900 MW or 13% lower than the forecast demand level of 23,030. Therefore, in order to resolve all of the thermal violations in SNE in 2015 via load reductions, load must be reduced by 13%. This compares closely on a percentage basis to the previous estimate of 3,400 MW, or 15% of SNE load.

Q. What does ICF's revised CLL analysis for 2015 show for Rhode Island?

A. In the revised analysis, a demand reduction of approximately 300 MW, or 14% of the load would be required to reach the CLL and resolve the thermal violations in Rhode Island. In the previous analysis the required load reduction was 800 MW or 38% of Rhode Island load. Therefore, the changes to the line ratings had a significant impact in Rhode Island. Even so, large reductions in demand are required to reach the CLL level. The CLL and required reduction for Rhode Island in 2015 are summarized in the table below.

Parameter	Previous Analysis	Revised Analysis
Load	2,095	2,095
CLL	1,285	1,785
Required Reduction	800	300
% of Load Reduced	38%	14%

Q. What does ICF's revised CLL analysis for 2020 indicate for SNE?

A. ICF's revised estimate of the CLL for SNE in 2020 is 19,419, which is 4,800 MW or 20% lower than the forecast demand level of 24,219. In order to resolve all thermal violations in SNE in 2020 through load reductions, load must be reduced by 20%. This compares closely on a percentage basis to the previous estimate of 5,300 MW, or 22% of SNE load.

Q. What does ICF's revised CLL analysis for 2020 indicate for Rhode Island?

A. In the revised analysis, a demand reduction of approximately 600 MW, or 27% of the load in Rhode Island would be required to resolve the thermal violations. In the previous analysis the required load reduction was 1,100 MW or 50% of Rhode Island load. Therefore, the changes to the line ratings had a significant impact in Rhode Island. Even so, large reductions in demand are still required to reach the CLL level. The CLL and required reduction for Rhode Island in 2020 are summarized in the table below.

Parameter	Previous Analysis	Revised Analysis
Load	2,206	2,206
CLL	1,106	1,606
Required Reduction	1,100	600
% of Load Reduced	50%	27%

II.4 Revised Assessment of NTA Based on Achievable Passive Demand Reductions

Q. Did you examine more than one passive demand reduction scenario?

A. Yes. ICF examined two scenarios: the Reference Case DR and the Aggressive Case DR scenarios. Thus, I will frequently discuss results for 8 situations: two years (2015 and 2020), two passive demand response cases (Reference DR and Aggressive DR Case), and two sub-regions (SNE and Rhode Island) (i.e., 8 results: 2 years x 2 DR cases x 2 sub-regions).

Q. Did you revise your estimate of achievable passive demand reductions?

A. No. These estimates range from 6 percent to 11 percent of load. The level of achievable reductions increases over time as there is more time for programs to take effect. For example, in SNE, the estimated reductions from passive demand programs in 2020 are 1439 MW, or 6% of load in the Reference DR Case, and 1,883 MW, or 8% of load in the Aggressive DR Case. In Rhode Island, the estimated reductions from passive demand programs in 2020 are 161 MW, or 8% of load in the Reference DR Case, and 235 MW, or 11% of load in the Aggressive DR Case.

Q. In light of the revisions to the CLL for SNE, were the achievable demand reductions from the Reference DR Case and the Aggressive DR Case sufficient to provide a passive DR only NTA?

A. No. In the Reference DR Case, the achievable demand reductions for SNE were only 12% and 30% of the required reductions in 2015 and 2020, respectively. In the Aggressive DR Case, the achievable demand reductions for SNE were only 14% and 39% of the required reductions in 2015 and 2020, respectively. The table below compares the required demand reduction in the revised case to the achievable Passive DR for SNE.

Year	Revised Required Load Reduction (MW)	Reference DR Case Achievable Passive DR		Aggressive DR Case Achievable Passive DR	
		Capacity (MW)	% of Revised Required Reduction	Capacity (MW)	% of Revised Required Reduction
2015	2,900	342	12%	405	14%
2020	4,800	1,439	30%	1,883	39%

Q. How do these SNE revised results compare to the previous results?

A. The difference is small. For example, in the previous estimate, the achievable reduction under the Aggressive DR Case was 36% of the required level in 2020. The revised estimate is 39%.

Q. In light of the revisions to the CLL for Rhode Island, were the achievable demand reductions from the Reference DR Case and the Aggressive DR Case sufficient to provide a passive DR only NTA?

A. No. In the Reference DR Case, the achievable demand reductions for Rhode Island were 16% and 27% of the required reductions in 2015 and 2020, respectively. In the Aggressive DR Case, the achievable demand reductions for Rhode Island were 20% and 39% of the required reductions in 2015 and 2020, respectively. The table below compares the required demand reduction in the revised case to the achievable Passive DR for Rhode Island.

Year	Revised Required DR Reduction (MW)	Reference DR Case Achievable Passive DR		Aggressive DR Case Achievable Passive DR	
		Capacity (MW)	% of Revised Required Reduction	Capacity (MW)	% of Revised Required Reduction
2015	300	47	16%	61	20%
2020	600	161	27%	235	39%

Q. How does this compare with the previous estimate for Rhode Island?

A. The gap between required and achievable passive demand reductions is still large but not as large as previously. For example, in the previous estimate, the achievable reduction in the Aggressive DR Case was 21% of the required level in 2020. The revised estimate is 39%.

Q. Can you express the gap in MW terms rather than percent of required reductions?

A. Yes. These MW gaps are shown below for both the Reference Case DR and Aggressive Case DR. For example, in 2020, in SNE, the revised estimate of the gap between required reductions and available reductions under the Aggressive DR Case was 2,917 MW which was 500 MW less than the previous estimate. In 2020, in Rhode Island, the revised estimate of the gap was 365 MW or 500 MW less than the previous estimate of 865 MW.

Gap Between Required and Achievable Passive Demand Reductions –Reference DR Case

Region - Year	Previous Gap (MW)	Revised Estimated Gap (MW)	Difference (MW)
SNE – 2020	3,861	3,361	-500
Rhode Island - 2020	939	439	-500

Gap Between Required and Achievable Demand Reductions – Aggressive DR Case

Region - Year	Previous Gap (MW)	Revised Estimated Gap (MW)	Difference (MW)
SNE – 2020	3,417	2,917	-500
Rhode Island - 2020	865	365	-500

II.5 Creating A Demand Only NTA – Passive DR Plus Incremental Active DR

Q. What was the next step after estimating potential passive demand resources in the analysis described in the ICF Report?

A. ICF then evaluated potentially available active demand resources to fill the gap in passive demand resources – i.e., creating a Demand Only NTA consisting of achievable Passive DR and incremental Active DR.

Q. What incremental active DR was considered?

A. There are two types of active DR, emergency generation and interruptible load. ISO-NE already has reached the maximum allowable emergency generation resource amount of 600 MW, and hence, we considered the only alternative active resource, interruptible load incremental to the amounts in the FCA.

Q. What was the outcome of that evaluation?

A. ICF found that it is not reasonable to achieve the required levels of active demand resources in 2015, and that achieving the required 2020 levels would require unprecedented growth levels to be maintained for the next several years.

Q. Does this conclusion change under the revised results?

A. No. In SNE, an additional 2,917 MW to 3,361 MW of interruptible load would be required in 2020 depending on which passive DR case is assumed. This is 13% to 15%

of the load. In Rhode Island, the incremental interruptible load required would be 365 MW to 439 MW, or 17% to 20% of load, which is still large. While this is less than the 865 MW to 939 MW reductions estimated previously, it is still not reasonable to achieve this level of reduction. As is discussed below, even the lower requirements for interruptible load in the combination NTA case are very challenging. Hence, these reductions are extremely challenging and achieving them is unreasonable.

II.6 Assessing Combination Supply and Demand NTA

Q. What was required to achieve the combination NTA?

A. By 2020, a total of 1,439 MW to 1,883 MW of central station generation was added in SNE from the ISO-NE Interconnection Queue in addition to the Reference Case DR or the Aggressive Case DR. Put another way, in order to implement the combination supply and demand NTA, a significant amount of new generation capacity must be sited, permitted, contracted, financed, and built in addition to the incremental passive DR programs being successfully implemented. In Rhode Island, 261 MW of central station generation capacity was assumed to be added at six sites.

Q. Please summarize the revised estimate of the additional load reduction (i.e., additional interruptible load) required to resolve all thermal violations in SNE in the Combination NTA cases in 2015 and 2020.

A. ICF conducted a CLL analysis with the generation of the Combination NTA in place. The revised required additional demand reductions in SNE reached 10% to 12% of total forecast SNE load by 2020. This is in addition to the supply additions and Passive DR program results. This is summarized in the table below:

Year	Capacity		% of Load	
	Combination NTA Reference DR Case (MW)	Combination NTA Aggressive DR Case (MW)	Combination NTA Reference DR Case (%)	Combination NTA Aggressive DR Case (%)
2015	1,575	1,511	8	8
2020	2,882	2,437	12	10

In comparison, in the previous analysis, the incremental demand reductions in SNE were:

Year	Capacity		% of Load	
	Combination NTA Reference DR Case (MW)	Combination NTA Aggressive DR Case (MW)	Combination NTA Reference DR Case (%)	Combination NTA Aggressive DR Case (%)
2015	2,075	2,011	11	10
2020	3,382	2,937	14	12

Thus, while the additional load reductions are less in the revised analysis, they are still large especially when one factors in the implementation challenges of the passive DR programs, the supply additions and the need to achieve additional reductions via increasing amounts of interruptible load.

Q. Please summarize the revised estimate of the additional load reduction required to resolve all thermal violations in Rhode Island combination NTA cases in 2015 and 2020?

A. From the table below, the incremental demand reduction required to resolve all thermal violations in Rhode Island in 2015 in the combination NTA would be approximately 6 to 20 MW. In 2020, the amount required would be at least approximately 126 MW to 200 MW. Note, in 2020 126 MW to 200 MW is 6% to 9% of the Rhode Island load. Therefore, even under the combination NTA, total reductions in Rhode Island load in

2020 are 361 MW or 16% of forecast load (i.e., the sum of the Passive DR and the incremental Active DR required to cover the gap).

Year	Passive DR Case	Passive DR (MW)	Incremental Active DR – Interruptible Load (MW)	Total Demand Reductions (MW)	Central Generation (MW)	Total (MW)
2015	Reference	47	20	67	261	328
2015	Aggressive	61	6	67	261	328
2020	Reference	161	200	361	261	622
2020	Aggressive	235	126	361	261	622

II.7 Assessing Implementation Risks

Q. Do you think it will be possible to implement these combination case NTAs?

A. It will not be possible to implement these reductions by 2015, and very challenging and costly by 2020. I discuss the reasons for my concern in the ICF report and later in this testimony. I also refer here to recent developments in Rhode Island that may be relevant to implementation.

Q. Are there any programs in Rhode Island that might provide guidance for the implementation of a NTA designed to decrease demand in Rhode Island?

A. Yes. National Grid's Tiverton-Little Compton Non-Wires Alternative (NWA) pilot project is such a project.

Q. Please describe this Pilot Program?

A. As I understand it, the Company is seeking to provide 1 MW of load reduction over four years to allow deferral of a new substation feeder for that four (4) year period. The six year budget is approximately $1.7 million. The program ends in 2017.

Q. Is the Pilot Program assured of success?

A. No. The program is a pilot – i.e., it is an attempt by the Company to provide a non-wires alternative of passive and active DR to achieve load reduction. The program is especially challenging because the load is primarily residential. The outcome of the pilot will not be known for some time.

Q. What is the size of the Pilot program compared to the total demand reductions needed to eliminate the need for Interstate?

A. The Pilot is targeting 1 MW of demand reductions; for Interstate, by 2020, SNE requires 4,800 MW of reduction and Rhode Island requires 600 MW of reduction. By 2015, only 2 years from now, SNE requires 2,900 MW of reduction and Rhode Island requires 300 MW of reduction. Thus, the pilot is very small compared to the size of the programs associated with an NTA.

Q. Does the pilot program provide an indication of the cost of a vastly larger program?

A. Yes, but only to a very limited degree. There is significant uncertainty regarding the pilot and the relevancy of its costs to that of a massively larger endeavor. Thus, the pilot's costs only provide an indication of the *order of magnitude of costs*. This is because of several reasons. Some of these reasons are:

- The program is a pilot that has yet to be proven;
- Some of the costs are from funds previously set aside for demand side programs;
- The Tiverton-Little Compton load is not necessarily representative of the SNE total load;

- There might be a need to increase the incentives in order to increase the number of customers participating, and to increase the extent (e.g., number of hours of the year, total MWh) to which customers must function without electricity. This would raise costs, all else equal;
- There could be economies of scale, and economies of experience. This would lower costs, all else equal.

Q. Are you able to provide an order of magnitude estimate of the required demand reductions based on the Pilot costs?

A. Yes, but only as an illustration of the order of magnitude of costs, and without offering an opinion as to whether this level of load reduction is attainable or, if attainable, whether the cost estimate is reasonable. If the per MW costs of the Pilot Program were assumed sufficient and applicable to a larger scale program, SNE would require a budget of over $8.2 billion (4,800 MW x $1.7 million), and Rhode Island $1.0 billion (600 MW x $1.7 million).

Q. Is there still a need for a wires solution at the Tiverton substation?

A. Yes. Thus, far the wires solution is still required for 2014. As noted, the Pilot has only recently started and the outcome will not be known for some time.

Q. Are you offering an opinion on whether the Pilot is worthwhile?

A. No. I am pointing out that the Pilot experience and timing is inconsistent with achieving the very massive demand reductions needed for Interstate in a timely manner and that on an order of magnitude basis the costs are very large.

II.9 Assessing the Cost Impacts

Q. In the ICF Report, did you estimate the capital costs of any of the portfolios of non-transmission alternatives that you analyzed, as compared to those of Interstate?

A. Yes, we estimated the cost of hypothetical non-transmission alternative solutions based on the Combination NTA Cases as compared with the then-estimated cost of Interstate of $532 million. Our analysis is included as Appendix E to the ICF Report.

Q. Did you revise your cost estimates as the result of the correction in line ratings?

A. Yes. ICF revised its Combination NTA cost estimates for the Reference DR and Aggressive DR Cases.

Q. How do the Combination NTA costs change as a result of the correction of line ratings?

A. In the previous analysis the costs ranged from $15.8 billion to $20.1 billion. In the revised analysis the costs range from $10.7 billion to $11.0 billion. This is greater than 20 times the cost of Interstate on a capitalized basis.[2]

Q. What are your conclusions in light of the revised cost estimates?

A. The Interstate option is far more cost effective even with lower active DR costs and assuming the Aggressive DR Case.

II.10 Summary of Conclusions

Q. Please summarize the conclusions of the ICF Report.

A. We concluded, based on an intense and wide-ranging analysis of non-transmission alternatives available for Interstate, that no feasible and practical non-transmission alternative would meet the needs that Interstate is designed to meet. In addition, we

[2] For additional details on ICF's cost calculations, see Appendix E of the ICF Report.

concluded that any hypothetical non-transmission alternative that was considered would be unprecedented in scope, immensely costly, difficult or impossible to implement, and less flexible and robust in operation than Interstate.

Q. In light of the revised results, do you still believe these conclusions to be appropriate?

A. Yes. While the reduction in demand that has to be achieved in Rhode Island is less, there remain numerous problems with the NTAs:

- In all cases, the NTAs (Passive DR, distributed generation, and central station generating additions) do not provide sufficient resources to eliminate violations; still greater active demand resources are required – e.g., greater amounts of interruptible load must be added to FCA levels. In the case of the passive DR resources including distributed generation, the gaps between achievable levels and required reductions in 2020 were 61% to 70% of the required demand reduction in SNE and 61 % to 73 % in Rhode Island.
- Even in the combination NTA, Rhode Island not only must add generation, it must also decrease its load by 16% below 2020 forecast levels (the sum of passive DR and incremental active DR needed to fill the gap).
- The NTAs cost much more than the Interstate solution.
- Implementation of demand programs will be very challenging. For example achieving the demand reductions via passive demand resources in the Aggressive DR Case are likely to be difficult to achieve. Achieving additional active demand resources, i.e., incremental interruptible load, will be also be challenging. I return to this issue in the Rebuttal section of my testimony.

- In the Combination NTA, implementation of the supply programs will be very challenging as well. Significant central station generation resources are required in SNE (1,439 to 1,883 MW) and in Rhode Island (six additions totaling 261 MW). These additions may be difficult to site, permit, contract, finance, and construct, and could require significant lead time.
- While Rhode Island reductions are less than previously estimated, the SNE results are relatively unchanged. Thus, the magnitude of the problem in other areas is almost as large as it was in the previous analysis.
- Implementation requires a broad regional effort, which is more complicated than action by one state alone.

III. REBUTTAL TESTIMONY

Q. What does Mr. Booth say about the CLL analysis?

A. Mr. Booth states that "the factor of diversity" has not been considered in determining critical load levels and suggests that this factor might lead to deferral of the project.[3] More specifically, he states:

> *The critical load level (CLL) has been defined as the load level forecasted where reliability is effected on the bulk transmission area. This overall CLL was arrived at by adding each individual sub-region's CLL for the Southern New England territory to determine the overall CLL for the region. While this approach provides a worst case scenario for planning purposes it does not take into account the factor of diversity. Diversity on*

[3] See Booth Pre-Filed Testimony, pp. 9-10.

a system such as the one analyzed in New England will typically see a factor of 90% to 95% of the simple cumulative load level. This type of reduction may not change the outcomes provided on a large scale and how National Grid and the ISO should address whether such impact defers the need for the proposed IRP project.

Q. Do you agree with Mr. Booth?

A. No. The CLL is calculated for each region and accounts for conditions that can occur in each region. For example, the system conditions assessed for Rhode Island involved imports of power into Rhode Island. Similarly, the system conditions for the Eastern NE CLL analysis assumed imports into Eastern NE, and the system conditions for the Western NE CLL analysis assumed imports into Western NE. Each region may not simultaneously import the specified amount of power, but each should be able to reliably import power. Hence, characterizing this as a worst case analysis is not accurate; it is a reasonable basis for CLL analysis. Furthermore, with respect to diversity of demand levels, the CLL is derived using ISO-NE's coincident peak demand. During this peak hour, demand levels used in the analysis for each sub-region are occurring coincidently. These demands account for diversity in that a sub-region peak could be higher in other hours of the year, and are lower during the coincident peak. Thus, the CLL analysis is appropriate and accounts for load diversity.

Q. What does Mr. Booth say about implementing NTAs?

A. Mr. Booth adds four additional risks/challenges to NTA.[4] Specifically:

> *There are multiple problems associated with non-transmission alternatives, particularly at the level of active generation which would be required. First and foremost, there is simply not sufficient time to install the needed level of active distributed generation required to meet the load relief timeline. Second, the availability of land and the emissions issues present an additional hurdle which makes this solution not practical. Last, the cost is greater than Option A-1 and does not eliminate the need for transmission solutions. On page 16 of Mr. Rose's testimony, the essence of the overall challenges associated with a non-transmission alternative is clearly listed. I not only concur with this list of seven (7) challenges, I would add land risks, emission risks, reliability and outage risks of distributed generation, and loss of economic generation dispatch. At a minimum, I see the installation of the required level of integrated generation in Rhode Island presenting the following problems:*[5]
>
> *1. Availability of land and generation siting issues and environmental impact on virgin lands.*
>
> *2. Availability of adequate fuel supply, natural gas being the most likely choice.*
>
> *3. Adequate availability of gas pipeline capacity.*

---

[4] See Booth Pre-Filed Testimony, pp. 26-27.
[5] Booth pre-filed testimony, pp. 27 and 28.

4. Construction of high pressure natural gas lines and the routing and environmental impact.

5. Construction of the substation and switching station and transmission interface facilities and the environmental impact on virgin lands.

6. The duration associated with the generation addition process could be well beyond the time frame when transmission system stability and criteria violations are severe and in excess of the 800 MW up to 1,100 MW loss of load scenario.

7. The project construction cost would easily approach $1.6 billion in Rhode Island alone.

8. The 800 MW to 1,100 MW of generation only defers the transmission need and does not eliminate the need for the same transmission project in the future.

Q. What is your reaction?

A. I share Mr. Booth's strong concern about NTA implementation and did not mean my list of implementation problems to be exhaustive. However, it should be noted that distributed generation resources play only a limited role in our analysis in part because of the implementation challenges.

Q. What does Mr. Booth say about the dispatchability and reliability of NTAs?

A. Mr. Booth disagrees with the characterization of the dispatchability and reliability of NTAs.[6] Specifically, he states:

> *Mr. Rose's testimony indicates Non-Transmission Alternatives, including Demand Side Management (DSM), distributed generation capabilities, and Combined Heat and Power Resources (CHP), cannot be real time dispatched efficiently or effectively, they cannot be relied upon to a significant degree of reliability, and distributed generation can take a very long time to be brought on-line (up to 30 minutes). This has not been my experience with actual projects and equipment. The technology exists that allows distributed generation and CHP and DSM to be as reliable if not more reliable than nearly any other form of utility generation that can be brought on-line in a timely fashion. Combustive turbines and other gas fired generation can be block-started and on-line in a few minutes.*

Q. Do you agree with Mr. Booth?

A. No. While the technology exists to decrease the lead time for active demand resources, this would represent a departure for the standard ISO-NE arrangement for these resources. Thus, the costs and implementation challenges could be even larger. Furthermore, the performance characteristics are unlikely to ever reach those for transmission lines, especially regarding lead time and reliability. I believe it is appropriate to consider NTAs with resource characteristics that are in place in ISO-NE.

Q. What did the ICF report state in this matter?

---

[6] See Booth Pre-Filed Testimony, p. 27.

A. The report stated:

> *These demand and generation resources alone, or in combination, have the potential in some circumstances to defer or displace the need for upgrades to the existing transmission system, while maintaining the same level of reliability. However, they may not offer the same certainty offered through transmission projects. For example, to provide reliability benefits, active demand resources must be dispatched. Many of these resources can only be called on for short periods of time, and may take 30 minutes or longer to respond, if they do respond. Hence, they do not offer the same certainty as the transmission lines or components which are always present and have a very high availability*.

Q. Why do you continue to hold this opinion?

A. ISO-NE has the following description for active resources:

> *Real-time emergency generators are required to begin operating within 30 minutes, which results in increasing supply on the New England grid, and also to continue that operation until receiving a dispatch instruction allowing them to shut down*[7].

More generally, ISO-NE requires that to qualify for the Forward Capacity Market of ISO-NE units must be able to respond in 30 minutes. This is subject to measurement and verification and to audits, so the time would be 30 minutes or less for active demand

[7] ISO-NE Demand Response ISO New England Market, Introduction to Wholesale Electricity Markets November 2012

resources. For interruptible load, ISO-NE explains that, under its current FCM rules, demand response providers with Capacity Supply Obligations must reduce demand within 30 minutes of dispatch in the event of a capacity deficiency on the electric system as a condition of their Capacity Supply Obligation.[8] Lastly, the central station resources assumed in the combination NTA are frame[9] combined cycles. These plants typically require 2 hours to come on-line. Even simple cycle plants with similar prime movers take 30 minutes. Quick start generators units exist – e.g., 10 minutes or less – but they cost more per kW, and hence, I would have to raise the cost estimates for the NTAs if we were to assume they have quick start capabilities, and still not have the practically instantaneous performance of transmission.

Q. What does Mr. Booth say about the estimated cost of demand response?

A. Mr. Booth disagrees with the estimated cost of the aggressive demand response case. [10] Specifically:

> *On page 2 of Mr. Rose's testimony, he states the Aggressive Demand Response Case has a cost of $15.1 billion. Based on my experience, the cost would be between $4 and $5 billion. This is still significantly above the transmission solution cost.*

Q. What does Mr. Booth say about the costs of active demand?

A. Mr. Booth disagrees with cost of active demand.[11]

---

[8] FERC, Docket ER12-1627-000, Order on Proposed Tariff Revisions, Issued January 14, 2013, Page 4 Paragraph #10.

[9] There are two types of gas-fired power plants, frame and aero-derivative. Most power plants are frame plants, and have lower costs than aero-derivative plants.

[10] See Booth Pre-Filed Testimony, p. 27.

Q. What is your response?

A. I disagree. While, we have lowered our estimate of the costs due to the correction of line ratings in Rhode Island, the methodology is unchanged. As discussed in Appendix E of our report, there are three cost components:

- **Passive DR –** ICF based its estimates of the costs of passive demand resources on available actual cost experiences of utilities in Massachusetts and Connecticut.
- **Central Station Generation** - ICF used generally accepted costs for central station generation NTAs.
- **Incremental Active DR –** ICF estimates in Appendix E the cost of incremental interruptible load used to estimate costs of incremental active demand resources. This estimate is based on the principle that in order to convince load to be interruptible, they must receive a payment (or discount on their bill) at least equal to the value of the electrical supply forgone. This is referred to as Value of Loss of Load (VOLL). Note, the value of electricity can greatly exceed its cost, especially during peak demand conditions, and especially as the amount of interruptible load increases. The rate of cost increase can be very large not only because increasingly reluctant customers must be convinced to agree to interruption, but the number of hours of interruption increases as the CLL decreases. For example, lowering the maximum allowable demand at first only requires a few hours of interruption. As the maximum allowable demand decreases further, hours of interruption can greatly increase. This cost cannot be

[11] See Booth Pre-Filed Testimony, p. 25.

estimated based on experience since no one has experience with interruptible load of this magnitude. Furthermore, experience with interruptible load can be also misleading because of the potential for fatigue, i.e., the withdrawal of customers from interruptible load programs when they are frequently called upon to accept interruption of service. Also, ISO-NE has recently proposed a tightening of rules for interruptible load that qualifies under the ISO-NE FCM. Specifically, interruptible load will be required to offer interruption in the energy market at all times just like supply in order to receive payment. Currently, interruptible load is only called during OP 4 events.

Mr. Booth himself states:

> *A demand reduction, through demand side management resources and some forms of dispersed generation, in Rhode Island is neither practical nor feasible...... In addition, passive demand reduction is rarely achievable above 15%, and it does not have sufficient predictability to be relied upon for reliability and thermal load relief.*[12]

Q. Does this conclude your testimony?

A. Yes, it does.

[12] Booth, p. 26.