The Narragansett Electric Company

d/b/a National Grid (Rhode Island Reliability Project)

RIPUC Dkt. No. 4029

Testimony of

Kenneth K. Collison

February 20, 2009

Q. Please state your name and business address.

A. My name is Kenneth K. Collison 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. Please describe your background as it relates to this proceeding.

A. I am currently a Principal in the Energy and Resources practice area of ICF and I lead the Transmission and Ancillary Services Group in this practice. My expertise includes assessing wholesale power market conditions, including that of the New England ISO. I have carried out detailed transmission studies, cost-benefit analyses of electric generation and transmission projects, power markets restructuring studies, power price and congestion forecasting, generation interconnection studies, and power system reliability studies. In several power markets, I have led studies to determine the impact of major proposed transmission projects on the ability of the market operators to reliably meet system demand. My work often involves computer modeling of wholesale power market conditions and often supports strategic decision-making for market operators, utilities, developers and the financial community. For additional details, please see my resume, submitted as Attachment KKC-1.

Q. Describe the types of clients supported by your practice.

A. ICF supports both private and public sector prices. In the public sector, ICF has been the principal power consultant to the U.S. Environmental Protection Agency continuously for over 30 years, specializing in the analysis of the impact of air emission programs, especially cap and trade programs. ICF has also worked with the U.S. Department of

Energy, Federal Energy Regulatory Commission, Environment Canada, and numerous foreign governments, as well as with state regulators and state energy agencies, including those in California, Connecticut, Kentucky, New Jersey, New York, Ohio, Texas, and Michigan. In the private sector, ICF has provided forecasts and other consulting service for over 25 years to practically every major US electric utility including such companies as Duke, Dominion Power, FirstEnergy, Entergy, Florida Power & Light, Southern California Edison, Sempra, PacifiCorp, and Tucson Electric. ICF also provides assistance to financial institutions such as Credit Suisse, power marketers such as Mirant, fuel companies such as Peabody Coal Company, and independent power producers, including Sithe Global Power, Kelson Energy and Reliant Energy. ICF also works with Regional Transmission Organizations and similar organizations, including the Midwest Independent Transmission System Operator, the Electric Reliability Council of Texas and the Florida Reliability Coordinating Council.

Q. Have you testified before, or made presentations to other regulators?

A. Yes. I have testified before the Public Utilities Commission of Texas.

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 present and summarize a report prepared by ICF under my supervision. The report is titled "Assessment of Non-Transmission Alternatives to the NEEWS Transmission Projects: Rhode Island Reliability Project", dated August 2008 (the “Report”), which was Appendix F to the ER, and is submitted as Attachment KKC-2.

Q. Was this testimony, including the attachments, prepared by you or under your direction and control?

A. Yes.

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

A. ICF was retained by National Grid and Northeast Utilities to provide an assessment of the potential for alternative resources, on both the supply and demand side, to displace or defer the need for the Rhode Island Reliability Project (“RIRP” or “Project”) and the other projects which together comprise the New England East-West Solution (“NEEWS”) projects.

Q. How is your testimony organized?

A. My testimony is organized into three remaining sections:

- Summary of the testimony
- Review of the non-transmission alternatives analysis for the Rhode Island Reliability Project
- Conclusions

<u>SUMMARY OF TESTIMONY</u>

Q. Please summarize your testimony.

A. My testimony describes the study performed by ICF to determine the feasibility of non-transmission alternatives (“NTA”) to RIRP. The RIRP is a transmission upgrade project which has been proposed by National Grid to alleviate transmission constraints and improve the reliability of the power system in the greater Rhode Island area. RIRP is part of the NEEWS projects selected in combination as the most effective approach to address five major system reliability problems in southern New England. In addition to RIRP, NEEWS includes three other major transmission projects – the Interstate Reliability Project, the Greater Springfield Reliability Project, and the Central Connecticut Reliability Project.

NTAs refer to generation or demand resources that could possibly be used as a substitute for a transmission project(s). Effective NTAs must be able to provide reliability benefits similar to that of transmission solutions.

ICF evaluated the NTAs in a two-step process. First, ICF analyzed two separate configurations of the New England regional transmission system to determine the reliability benefits from the proposed RIRP transmission additions and upgrades for the first year of its operation, 2013. Next, ICF analyzed three main NTA scenarios to determine if the reliability benefits of these scenarios were comparable to that of RIRP. ICF also assessed the ability of the system to operate reliably if an important generation facility in Rhode Island were out of service.

The three main NTA scenarios were:

- NTA Scenario 1: Uniform load reduction in the Rhode Island zone.
- NTA Scenario 2: Local load reductions at key load points – the Drumrock, Kent County and Johnston substations – rather than uniform load reductions.
- NTA Scenario 3: Uniform load reduction in Connecticut as well as in Rhode Island.

Reliability benefits of RIRP and the NTA scenarios were assessed by performing detailed power-flow analyses to determine system performance under both normal and emergency conditions. System performance was measured by monitoring transmission lines for overloads, and transmission substations for voltage violations. For the power system to continue to operate reliably, the power flowing on each transmission line should remain below the appropriate ratings of the line.

ICF's study showed that RIRP resolved all line overloads and voltage violations, even when an important generation facility was out of service. On the other hand, the corresponding NTAs required to resolve all violations were unrealistic. In NTA Scenario 1 between 1,500 MW and 2,000 MW of incremental demand reduction had to be implemented to resolve all line overloads in the reference scenario. In NTA Scenario 2, all the demand (up to 294 MW of coincident peak load) at Drumrock, Kent County and Johnston substations was removed. Further, an incremental 1,000 MW of load reduction had to be applied uniformly in the rest of the Rhode Island zone to resolve all overloads. In NTA Scenario 3, in addition to an incremental uniform load reduction of 1,000 MW in Connecticut, an incremental uniform load reduction of at least 1,000 MW was also required in Rhode Island as well. The range of demand reduction required in these NTA scenarios represents 40 to 70 percent of Rhode Island's peak demand. This would be the equivalent of blacking out 40 to 70% of electric customers in Rhode Island.

In all three NTA scenarios, the important generating unit was kept in operation. Even more resources would be required in the scenario in which this unit is out of service. The demand reduction necessary to achieve reliability benefits similar to that of the Project therefore reflects an unrealistic level of resources.

Based on the study, ICF determined that there is no reasonable or realistic NTA scenario that could provide reliability benefits similar to RIRP and thus defer or displace the need for RIRP.

REVIEW OF THE NON-TRANSMISSION ALTERNATIVES ANALYSIS

Q. Please describe the Rhode Island Reliability Project.

A. The Rhode Island Reliability Project is a transmission upgrade project which has been proposed by National Grid to alleviate transmission constraints and improve the reliability of the power system in the greater Rhode Island area. RIRP is part of the larger NEEWS project which, in addition to RIRP, includes three other major transmission projects:

- Interstate Reliability Project,
- Greater Springfield Reliability Project, and
- Central Connecticut Reliability Project

The four NEEWS projects were selected in combination as the most effective approach to address five major weaknesses which ISO New England ("ISO-NE"), the regional transmission organization ("RTO") serving the New England electricity market, identified in its 2007 Regional System Plan.[1] RIRP is designed specifically to alleviate Rhode Island's dependence on single transmission lines or autotransformers for reliability. However, there are significant synergies resulting from the combined

[1] "2007 Regional System Plan," October 18, 2007, ISO New England.

implementation of the four NEEWS projects which further reinforce the transmission system. RIRP and the other NEEWS projects are described in more detail in Chapter 1 of the Report.

Q. Please describe what is meant by a non-transmission alternative.

A. A non-transmission alternative ("NTA") refers to a resource(s) that could possibly be used as a substitute for a transmission project(s). This includes generation and demand side resources. Effective NTAs must be able to provide reliability benefits similar to that of the target transmission project. NTAs may be individual resources such as energy efficiency measures, demand response, distributed generation, or central generation stations. They may also be combinations of these resources. In ICF's analysis the NTA options considered included Combined Heat and Power ("CHP") resources, Demand-Side Management ("DSM") resources, and central generation stations.

Q. Please describe what is meant by Combined Heat and Power resources.

A. These are resources that would be located on site, typically at larger industrial or commercial locations with both steam and electric power needs, and would be used as the primary source of power for that location such that there is no direct demand from the location for regional generation sources and hence no demand for transmission services.

Q. Please describe what is meant by Demand-Side Management resources.

A. DSM resources represent a large block of options that tend to reduce the demand for system generation and transmission services either through direct reductions in the load, or the addition of generation as a distributed source, i.e. distributed generation. Demand reductions may be either passive or active. Passive resources include resources such as energy efficiency programs that are tied to use of highly efficient equipment. Active resources include interruptible load contracts and distributed/emergency generators that can be responsive to system conditions or prices.

Q. How does the reliability benefit of transmission facilities compare to that of NTA resources?

A. Transmission systems tend to have a very high built in reliability factor. The probability of an unplanned outage of a transmission facility is very low. Further, the reliability planning criteria to which transmission projects are subject require that the transmission project withstand critical conditions, including second level contingencies and severe weather conditions. Therefore, transmission projects inherently provide a higher level of reliability than NTAs. In determining the amount or level of NTAs required to effectively serve as alternatives to transmission projects, it is important to ensure that the NTAs provide a level of reliability comparable to that of the transmission project.

Q. Do transmission facilities inherently provide a higher level of reliability than generation facilities used as NTA resources?

A. Yes. Because of their mechanical nature, generating facilities have greater forced outage rates than transmission lines. In addition, unlike transmission facilities, generation facilities are also subject to fuel availability and air emission control criteria. Therefore a generator will have a much lower expected availability than a transmission facility. Further, the reliability benefit of any individual NTA, or combinations thereof can vary significantly.

Q. Do transmission facilities inherently provide a higher level of reliability than demand response resources used as NTA resources?

A. Yes. Resources such as demand response are not considered as dependable as transmission facilities. Demand response resources may commit for an individual year but have no long-term commitment mechanism in place and are also highly subject to economic conditions. Further, demand response resources are generally not automated measures that can be entirely relied on to operate instantly but participants must be contacted to implement the measures. Hence their response when called upon, may be extremely slow. As such, the inherent reliability offered by a demand response resource is generally less than a long-term transmission facility. In determining the amount or level of NTAs required to effectively serve as alternatives to transmission projects, it is important to ensure that the alternatives provide the same or very similar level of reliability as the transmission project.

Q. Please describe the approach used to evaluate the NTAs.

A. ICF evaluated the NTAs in a two-step process. First, ICF analyzed two separate configurations of the New England regional transmission system to determine the reliability benefits from the proposed RIRP transmission additions and upgrades for the first year of its operation, 2013. Next, ICF analyzed various NTA scenarios to determine if the reliability benefits of these scenarios were comparable to that of RIRP.

Q. Please describe the two configurations of the New England regional transmission system used in the first step of the NTA evaluation.

A. ICF developed the two configurations from power-flow models of the New England transmission system that were representative of a summer peak demand period in 2013. The first, referred to as the Pre-RIRP Case, represented the New England transmission system assuming the Project, as well as the other components of NEEWS, was not implemented. The second case, referred to as the Rhode Island Case represented the transmission system assuming the Project was implemented. The estimates of expected non transmission resources – CHP, DSM and generation resources – based on both the technical potential and the economic potential for these resources, were incorporated into both cases. Chapter 5 of ICF's Report describes the process used to develop these cases in more detail.

Q. What assumptions were developed by ICF to perform this study?

A. ICF established baseline assumptions for a peak summer day during the expected online year of the Project, 2013. The key assumptions include (A) 2013 peak demand projection; (B) load adjustments for DSM, CHP and losses; (C) projected generation resource additions and retirements; (D) generation dispatch to reflect forced outage rates and spinning reserve requirements; and (E) transmission topology based on power-flow models of the New England transmission system that were representative of a summer peak demand period in 2013. The assumptions are described in detail in Chapters 2 through 5 of the Report.

Q. Please explain how ICF assessed the reliability benefits of RIRP.

A. ICF's study was designed to test the operation of the New England transmission system under the ISO-NE standards and criteria, which require that the system continue to serve its load reliably during anticipated transmission facility outages. The standards and criteria also require that the New England transmission system maintain adequate capability to transfer power within New England and between New England and neighboring markets.

This test was carried out for the two configurations of the New England regional transmission system mentioned above, that is, the Pre-RIRP Case and the Rhode Island Case, which had RIRP implemented.

To determine the ability of the system to continue to serve its load reliably during anticipated facility outages, ICF performed a detailed power-flow analysis of the system, assuming both normal and emergency conditions. Normal conditions imply that all generation and transmission facilities continue to operate as expected on a peak summer day. First, ICF assessed system performance under normal conditions assuming no unplanned failure of any transmission element, such as a transmission line, a transformer, a circuit breaker, or a pair of transmission lines on a multiple circuit transmission tower. Next, the process was repeated for the unexpected failure of key transmission elements.

A similar analysis was then conducted to evaluate system performance in the situation following the outage of a single transmission element, when a second element was then considered to fail. In this analysis, the transmission system was first allowed to adjust the flows of power following the single element loss.[2]

System performance was measured by monitoring transmission lines for overloads, and transmission substations for voltage violations. To continue to operate reliably, the

[2] The loss of a single transmission element is referred to as an N-1 contingency. The loss of a single transmission component followed by the loss of a second component is referred to as N-1-1 contingency.

power flowing on each transmission line should remain below the emergency ratings of the line.

Furthermore, ICF assessed the ability of the system to operate reliably if an important generation facility in Rhode Island was out of service. In this case the generation facility was taken out of service and other generators were adjusted to replace the lost output. The performance of the system was then examined as described above.

The reliability assessment for the Project was carried out by comparing the performance of the Pre-RIRP Case to that of the Rhode Island Case. The reliability benefit of the Project was derived from its ability to resolve any violations that existed in the Pre-RIRP Case.

ICF's approach is described in more detail in Chapter 1 of the report.

Q. Please explain how ICF assessed the reliability benefits of the NTA scenarios.

A. Starting from the Pre-RIRP Case that already included aggressive estimates of demand reduction, ICF developed other NTA scenarios by implementing additional DSM resources. ICF assessed the reliability benefits of each of these NTA scenarios in a manner similar to the approach used for the Project. That is, ICF performed a detailed power-flow analysis of the New England power system with each scenario implemented in turn, and ICF determined the ability of the system to continue to serve its load during anticipated facility outages, assuming both normal and emergency conditions. System performance was measured by monitoring transmission lines for overloads, and transmission substations for voltage violations. For each NTA scenario the level of DSM resources was increased until all line overloads were resolved, similar to the reliability benefits of the Project. ICF then reviewed each NTA scenario to determine if a reasonable level of DSM and other NTAs could provide benefits comparable to the Project.

Q. What NTA scenarios did ICF analyze?

A. ICF analyzed three main NTA scenarios, as described in Chapter 6 of the Report. The three scenarios are:

- NTA Scenario 1 – Uniform load reduction in Rhode Island: Load in the Rhode Island zone was decremented uniformly until all line overloads were resolved.
- NTA Scenario 2 – Local load reductions at key load points: This scenario examined the importance of the location of load reductions on power-flow and line loadings. Under this scenario, local load reductions were assumed at key load points rather than uniform load reductions. The Drumrock, Kent County and Johnston substations were identified as key contributors to the identified reliability issues, and the load at these three substations was set to zero.
- NTA Scenario 3 – Uniform load reduction in Connecticut and Rhode Island: This case was analyzed to consider if loop flows and exports to Connecticut may be contributing to the overloads. In this case, a uniform load reduction was applied in Connecticut as well as in Rhode Island.

Q. Did ICF observe violations in the Pre-RIRP Case?

A. Yes. As discussed, the Pre-RIRP Case already included estimates of expected non-transmission resources based on the technical and economic potential for these resources.

ICF found that the non-transmission resources in the Pre-RIRP Case were not sufficient to resolve all line overloads.

Q. Please explain.

A. ICF observed that especially under conditions where one or more lines were out of service, transmission facilities in the Rhode Island zone would be loaded above their safe operating limits. This was even more severe when an important generation unit was out of service. Therefore, without the Project, NTAs above and beyond that in the Pre-RIRP Case would be required to resolve all the violations. Detailed results for the reference scenario and the scenario with the generating unit out of service are shown in Chapter 6 of ICF's Report.

Q. Did the Project resolve these violations?

A. Yes. As shown in Chapter 6 of ICF's Report, line flows on the critical transmission facilities were all significantly below their respective limits following the implementation of the Project. In both the reference scenario and the scenario with an important generating unit out of service, the Project successfully resolved all violations.

Q. What was the result of the analysis of NTA Scenario 1?

A. ICF found that if demand was decremented uniformly in the Rhode Island area, between 1,500 MW and 2,000 MW of demand reduction would be needed to resolve all line overloads in the reference scenario. This is over and above the aggressive estimate contained in the Pre-RIRP Case. Since this represents 50 to 70% of Rhode Island's peak load, it is considered an unrealistic level of resources. Consequently, ICF did not perform the analysis with an important generation unit out of service, in which case, even more resources would be required.

Q. What was the result of the analysis of NTA Scenario 2?

A. Setting the demand at Drumrock, Kent County and Johnston substations to zero removed 294 MW of coincident peak load. However, this was not sufficient to resolve all overloads. An additional 1,000 MW of load reduction had to be applied uniformly in the rest of the Rhode Island zone to resolve all overloads. Since this represents about 40% of Rhode Island's peak load, it is considered an unrealistic level of resources. Consequently, ICF did not perform the analysis with an important generation unit out of service, in which case, even more resources would be required.

Q. What was the result of the analysis of NTA Scenario 3?

A. Applying a uniform load reduction of 1,000 MW in Connecticut was not sufficient to resolve all overloads. A load reduction of at least 1,000 MW would be required in Rhode Island as well. Since this represents about 40% of Rhode Island's peak load, it is considered an unrealistic level of resources. Consequently, ICF did not perform the analysis with an important generation unit out of service, in which case, even more resources would be required.

Q. What were the insights from ICF's analysis of the NTA scenarios?

A. Even with all Rhode Island generation in operation, ICF found that the demand in the Rhode Island zone would have to be reduced by 40 to 70 percent of the peak demand level in order to resolve line overloads if the Project is not implemented. Even more resources would be required in the scenario in which an important generation unit is out of service. The demand reduction necessary to achieve reliability benefits similar to that of the Project therefore reflects an unrealistic level of resources.

Q. Based on ICF's study, is there a reasonable NTA scenario that can provide reliability benefits similar to the Project and thus defer or displace the need for the Project?

A. No.

Q. Please describe the power flow software used for the analysis.

A. ICF used the PSLF™ (Positive Sequence Load Flow) model developed by GE. PSLF is designed to provide comprehensive and accurate load flow, dynamic simulation and short circuit analysis and is widely used in the utility industry. Results of the PSLF load flow include individual line flows and overloads.

Q. Did ICF consider transmission alternatives to RIRP?

A. No. ICF's scope of work was to evaluate non-transmission alternatives to the Project.

CONCLUSIONS

Q. Please summarize the conclusions of the analysis.

A. In conclusion, based on the detailed technical analysis of non-transmission alternatives available for the RIRP project, I find that the NTA options required to achieve reliability benefits similar to that of RIRP are not realistic or reasonable, and hence they are not NTA solutions. Therefore, no satisfactory NTA solutions are available for the RIRP project.

Q. Does ICF continue to support the conclusion of the RIRP NTA performed in 2008 analysis that no reasonable alternatives to the RIRP project exist?

A. Yes.

Q. Does this conclude your testimony?

A. Yes, it does.

Attachments to Testimony of

Kenneth K. Collison

KKC-1	Kenneth K. Collison Resume
KKC-2	"Assessment of Non-Transmission Alternatives to the NEEWS Transmission Projects: Rhode Island Reliability Project", dated August 2008

KENNETH COLLISON **ICF INTERNATIONAL**
Principal

EDUCATION

2002 MBA, Management and Consulting, Massachusetts Institute of Technology, Cambridge, MA
2001 M.S., Technology and Policy, Massachusetts Institute of Technology, Cambridge, MA
1989 B.S., Electrical and Electronic Engineering, University of Science and Technology – Ghana

EXPERIENCE OVERVIEW

Mr. Kenneth Collison joined ICF Consulting in July 2002 and currently leads ICF's Transmission and Ancillary Services Group within the Wholesale Power Practice. Mr. Collison's expertise is in transmission studies, power system reliability studies, critical infrastructure protection, transmission and ancillary services valuation, generation analysis, utility restructuring, and strategic studies. Mr. Collison has developed full AC non-linear power flow models for detailed power system engineering studies including power system reliability assessment, contingency analysis and total transfer capability analysis for the networks of several power pools in the US. In several power markets, Mr. Collison has led studies to determine the impact of major proposed transmission projects on the ability of the market operators to reliably meet system demand. Mr. Collison led a study to assess the benefits of a new transmission line, proposed by Kelson Transmission, which will connect non-ERCOT areas in east Texas to the Houston zone of ERCOT. Mr. Collison filed testimony before the Public Utilities Commission of Texas and testified in support of Kelson Transmission's application for a Certificate of Convenience and Necessity to construct the new transmission line. Mr. Collison was also the transmission lead during ICF's study of the costs and benefits of the GridFlorida RTO, a study that examined in detail the cost of implementing an independent system operator for the Florida market and the benefits in reduced cost to consumers over a 12-year timeframe. Similarly, he provided transmission expertise during ICF's analysis of the benefits of the Midwest ISO's Day-2 market, which determined the benefits of the transition of the Midwest ISO to a fully competitive market with centralized commitment and dispatch. In addition, Mr. Collison has managed several security constrained optimal power flow studies using linear optimization-based power flow simulation models to determine the economic dispatch of units within system stability and transmission limits. He has prepared congestion forecasts and determined the related congestion revenue and costs for the interconnected transmission networks in the US. Mr. Collison also specializes in risk-based and readiness reliability assessment within the framework of the mandatory NERC reliability standards. Prior to joining ICF Consulting, Mr. Collison worked as a Research Associate at the Massachusetts Institute of Technology (MIT) Laboratory for Energy and the Environment, studying innovative methods to manage congestion and optimize inter-regional transactions in the US electricity markets. He also worked as an Electrical Engineer with Kaiser Aluminum. Mr. Collison holds a Master of Business Administration degree and a Master of Science degree in Technology and Policy from MIT, and a Bachelor of Science degree in Power Systems Engineering from the University of Science and Technology – Ghana.

RELEVANT EXPERIENCE

<u>Wholesale Power Market Analysis:</u> Mr. Collison has performed studies for several clients in the power generation sector that required a detailed analysis of the power markets. For these clients Mr. Collison assessed generation facility dispatch, forecast energy price and estimated gross revenues. In many cases Mr. Collison has used the GE Energy MAPS model to develop a least cost economic model of the US power market, while enforcing transmission and stability limits to forecast hourly dispatch and locational prices and to assess the impact of transmission constraints on the facilities.

<u>Asset Valuation and Market Studies:</u> Mr. Collison has led studies focusing on the valuation of generation assets in several markets. Using fundamentals analysis, these studies have included forecasts of energy and capacity prices and assessments of facility dispatch. Further, facility performance was assessed under alternative scenarios to assess the impact of key market drivers – fuel prices, demand, allowance

prices, air regulatory polices, resources additions or retirements, and other parameters – on the facility revenue. Many of these studies have been used to support project financings.

Transmission Analysis: Mr. Collison's transmission analysis effort includes interconnection feasibility studies, power deliverability assessments, congestion forecasts, FTR price forecasts, reliability studies, and transfer capability assessments.

- Interconnection Feasibility Studies: For planned generation facilities Mr. Collison has managed detailed power flow studies to determine the transmission facility additions and upgrades that would be necessary for interconnection and operation. Using the PSLF and PowerWorld power flow models, seasonal snapshots of the power system are examined with and without the planned facility to determine the incremental effect of dispatch from the facility on the transmission grid. The system is examined under both normal and emergency conditions to ensure that likely operating scenarios are properly accounted for. Transmission facility thermal and voltage limit violations due to the facility dispatch are noted, and the cost of upgrades to alleviate the violations is estimated. Clients have used the results to determine appropriate interconnection substations for their facilities.
- Power Deliverability Assessments: Mr. Collison has helped clients assess the ability of their units to deliver power to particular load centers subject to transmission facility operating limits. Mr. Collison develops models similar to those used in the interconnection feasibility studies and simulates different levels of power transfer from the source (generation facility) to the sink (load center). Transmission facility thermal and voltage limit violations due to the transactions are noted, and the cost of upgrades to alleviate the violations is estimated. Based on such analyses, clients are able to determine favorable markets and assess the feasibility of proposed power contracts.
- Congestion and FTR Price Forecasts: Mr. Collison has assessed congestion risk for clients by forecasting congestion in the power markets and, if required, forecasting FTR prices. Mr. Collison uses hourly nodal models of the power markets to simulate dispatch and power flows in the transmission network. These models have detailed representation of generation and transmission facilities in the market, and transmission facility thermal and stability limits are strictly enforced. A forecast is prepared of the congested facilities, the number of hours of congestion, and the price impact. The FTR price is estimated from the difference between congestion components of the energy prices.
- Reliability Studies: Mr. Collison has analyzed many power networks to assess the impact of planned upgrades or additions on system reliability. Many of these studies have demonstrated the benefits and supported the implementation of new transmission projects. Mr. Collison led a team to prepare seasonal snapshot model of the northeast US power market to support a client's major transmission project. The models were prepared to reflect normal and emergency operation of the transmission network in the future. Generation facility additions and retirements, demand growth, and demand response were incorporated and transmission thermal and stability limits were strictly enforced. The analysis showed that the new project alleviated thermal and voltage violations and improved the ability of the system to serve the increased demand reliably.
- Transfer Capability Assessment: Mr. Collison leads the effort to estimate the power transfer capability between load zones, utilities, or power markets for ICF internal use and for clients. This is critical in properly capturing trade between markets.

Renewable Market Analysis: Mr. Collison has helped clients to assess sites for wind generation vis-à-vis the accessibility of transmission and the ability to deliver the power to load centers. He has also worked with clients to determine the ability of proposed cleaner generation facilities to displace dispatch from existing "dirtier" facilities and thus reduce overall emission of pollutants.

Regulatory Proceedings: Mr. Collison has assisted in the preparation of testimony for state proceedings. These include siting of power generation and transmission facilities; utility cost of service proceedings; market structure; tariff rates; and air quality improvements. Mr. Collison filed testimony before the Public Utilities Commission of Texas and testified in support of Kelson Transmission's application for a Certificate of Convenience and Necessity to construct a new transmission line that will connect non-ERCOT areas in east Texas to the Houston zone of ERCOT. The new line would enable generation in the non-ERCOT areas in east Texas to access the Houston zone of ERCOT, potentially providing relatively cheaper generation to the ERCOT market.

Cost Benefit Studies: Mr. Collison has led and performed studies to estimate the costs and benefits of proposed projects and programs to help clients understand the value of these projects and programs relative to the cost. Mr. Collison's recent analysis has included cost-benefit studies for market restructuring programs and proposed transmission line projects.

- *Analysis of the Benefits of the Midwest ISO's Day-2 Market:* Mr. Collison was the transmission lead in the study to determine the benefits of the transition of the Midwest ISO to a fully competitive market with centralized commitment and dispatch. This analysis involved detailed modeling of the US Eastern Interconnect with a focus on the Midwest ISO footprint under security constrained unit commitment and economic dispatch conditions. ICF coordinated with dozens of stakeholders to collect data reflecting the operation of the Midwest ISO system. Using the data, ICF calibrated its model to a recent operating year and estimated the benefits of the market transition by comparing an actual Midwest ISO Day-2 operation to a simulated Midwest ISO Day-1 operation. Additionally, ICF estimated the maximum benefits achievable from an optimal Day-2 operation to reflect the potential to increase savings to the Midwest ISO consumers from incremental operational improvements to current Day-2 operations.
- *GridFlorida RTO Cost Benefit Analysis:* Mr. Collison provided transmission expertise to utilities in the Florida power market in determining the costs and benefits of restructuring the multi-utility control area operation to a centrally coordinated and dispatched market. Mr. Collison's contribution included model calibration to a base year, then modeling least cost economic dispatch subject to transmission line and system stability limits going forward under both current and RTO operation. Based on the results of the study the incumbent utilities and the Florida Reliability Coordinating Council (FRCC) will assess the viability of a transition to an RTO structure.
- *Benefits of Transmission Lines:* Mr. Collison has led studies to assess the economic benefits of proposed transmission projects in several power markets. A study for a major utility in the PJM market determined the benefits of a major transmission project in the Mid-Atlantic and supported the client's application for approval in PJM's regional transmission plan. In Texas, Mr. Collison assessed the benefits of a large transmission project that would interconnect the Houston load zone with generation in a non-ERCOT section of Texas. The project would enable the importation of significant amounts of power into the Houston load pocket. The study will support a filing before the Public Utility Commission of Texas.

SELECTED PUBLICATIONS AND PRESENTATIONS

Rose J., K. Collison, K. Kumaraswamy. "Addendum to the Independent Assessment of Midwest ISO Operational Benefits". May 2007.

Rose J., C. McCarthy, K. Collison, H. Parmar. "Independent Assessment of Midwest ISO Operational Benefits". February 2007

Ofori-Atta K., J. Rose, C. McCarthy, H. Parmar, K. Collison, E. Roseman, S. Muthiah, M. Scheller. "Cost-Benefit Study of the Proposed GridFlorida RTO." December 2005.

Ofori-Atta K., K. Collison. "Modeling and Forecasting Operating Reserve Prices in LMP Markets." Presented at EUCI Ancillary Services Conference, October 2003.

Collison K. "A Practical Approach to Optimal Pricing and Implementation of Inter-regional Transactions in Electricity Markets Under Restructuring." June 2001

Yoon, YT, M.D. Ilic and K.K.Collison. "Efficient Implementation of Inter-regional Transactions." January 2001, pp 36.

Yoon, YT, J.R. Arce, K.K.Collison and MD Ilic. "Implementation of Cluster-based Congestion Management Systems." May 2000, pp 21. Presented at ICPSOP 2000 – Restructuring The Power Industry For The Year 2000 And Beyond in July 2000.

Yoon, YT, K.K.Collison, J.R. Arce and MD Ilic, Congestion Management System Methods: Comparison on the 118 Bus System, July 2000, pp 21. Presented at 32nd Annual North America Power Symposium (NAPS 2000), Waterloo, Ontario, Canada in October 2000.

Yoon, YT, MD Ilic, K.K.Collison, and J.R. Arce, Practical Implementation of Congestion Cluster Pricing Method, August 2000, pp 30.

TESTIMONY

- Supplemental Direct Testimony of Kenneth K. Collison for Kelson Transmission Company, LLC, Before the State Office of Administrative Hearings, Application of Kelson Transmission Company, LLC for a Certificate of Convenience and Necessity for the Amended Proposed Canal to Deweyville 345 kV Transmission Line Within Chambers, Hardin, Jasper, Jefferson, Liberty, Newton and Orange Counties, SOAH Docket No. 473-08-3341, PUC Docket No. 34611, (Public Utilities Commission of Texas), June 18, 2008.
- Prepared Testimony of Kenneth K. Collison on Behalf of Communities Against Regional Interconnect (CARI), Before the State of New York Public Service Commission, In the Matter of New York Regional Interconnect, Case No. 06-T-0650, January 9, 2009.

EMPLOYMENT HISTORY

ICF Consulting	Principal	2008
ICF Consulting	Senior Manager	2007
ICF Consulting	Project Manager	2005-2006
ICF Consulting	Senior Associate	2002-2004
MIT CEEPR	Research Assistant	2001-2002
MIT Energy Laboratory	Research Assistant	1999-2001
Kaiser Aluminum	Electrical Engineer	1990-1999

Assessment of Non-Transmission Alternatives to the NEEWS Transmission Projects: Rhode Island Reliability Project

Prepared for:

National Grid

Prepared by:

ICF International

August 2008

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EXECUTIVE SUMMARY

I. Introduction

The Rhode Island Reliability Project (the "Project") is a transmission upgrade project which has been proposed by National Grid to alleviate transmission constraints in the greater Rhode Island area. The Rhode Island Reliability Project consists of a set of transmission upgrades in the Rhode Island area that are designed to eliminate major constraints and reinforce limiting elements in the area. The Project is part of the larger New England East-West Solution (NEEWS) which, in addition to the Rhode Island Reliability Project, includes three other major transmission projects:

- Interstate Reliability Project
- Greater Springfield Reliability Project
- Central Connecticut Reliability Project

The four NEEWS projects were selected in combination as the most effective approach to address the five major weaknesses which ISO New England (ISO-NE), the regional transmission organization (RTO) serving the New England electricity market, identified in its *2007 Regional System Plan*.[1] The geographical location of the weaknesses is shown in Exhibit ES-1 as are the four projects which comprise NEEWS. Each of the four projects includes the installation of a new 345 kV line among other components, and each individually addresses at least one of the key weaknesses that ISO-NE identified. The four projects have been designed to be complementary. Therefore, the benefits of the NEEWS projects as a whole, far exceeds that of the four component projects if considered individually. The Rhode Island Reliability Project is designed specifically to alleviate Rhode Island's dependence on limited transmission lines and autotransformers.

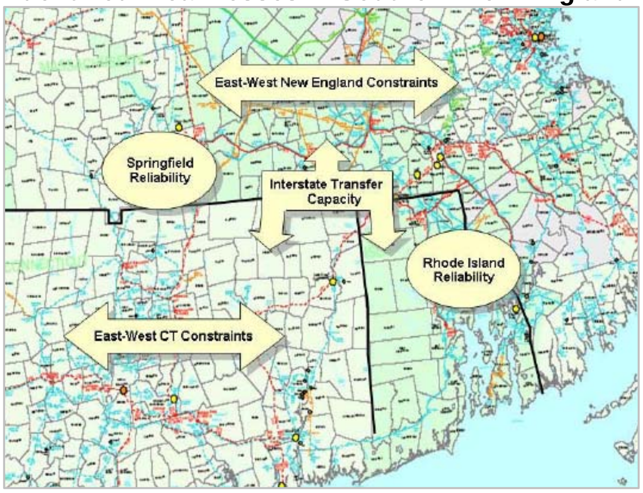
ICF Resources LLC (ICF) was retained by Northeast Utilities and National Grid to prepare an analysis considering the potential for alternative resources, on both the supply and demand side, to displace or defer the need for the Rhode Island Reliability Project (the "Project") and the other NEEWS projects.

To perform the analysis of the effect of non-transmission alternatives on the Rhode Island Reliability Project, ICF has considered the addition of demand resources (including distributed generation), traditional generation supply, and combined heat and power supply options and examined the impact of a large total combined penetration of these resources on the overall reliability of the area as determined through power-flow modeling analysis at peak conditions for pre- and post-Rhode Island Reliability Project cases. In addition, given the synergies inherent among the four projects, ICF has examined a similar set of power-flow cases, pre- and post-NEEWS, for the impact on the local Rhode Island constraints as well as the system. While the first set of cases isolates the direct impact of the Rhode Island Reliability Project, the latter provides an assessment of the interaction of the Project with the other components of NEEWS.

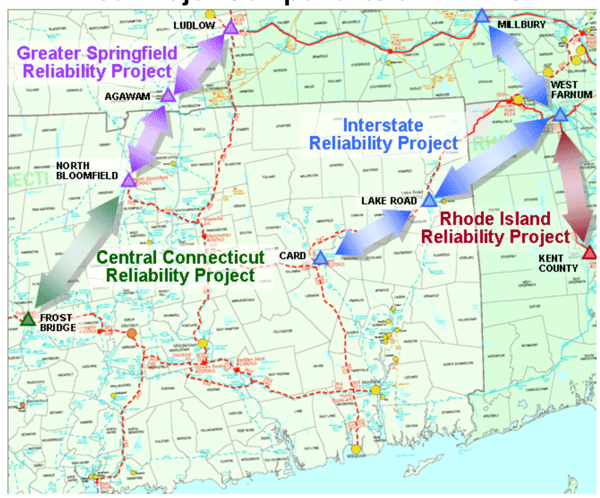
[1] "2007 Regional System Plan," October 18, 2007, ISO New England.

Exhibit ES-1
Identified Weaknesses in Southern New England and the Four Major Components of NEEWS

Identified Weaknesses in Southern New England



Four Major Components of NEEWS



Sources: ISO New England's "Southern New England Transmission Reliability Report 1 Needs Analysis," January 2008; and Northeast Utilities web site: http://www.transmission-nu.com/residential/projects/NEEWS/default.asp#

This report is focused on the Rhode Island Reliability Project solution. The remainder of this Executive Summary will briefly describe ICF's approach for analyzing alternatives to the Project, conducting the power-flow analysis, and conclusions of the power-flow analysis.

II. Background

In terms of reliability, ISO-NE is obligated to meet, at a minimum, the electric industry reliability standards set by the North American Electric Reliability Corporation (NERC), the electric reliability standards development and enforcement body for North America. NERC has established rules and criteria for all geographic areas in North America. The performance of the New England transmission system is also governed by reliability standards and criteria established by the Northeast Power Coordinating Council, Inc. (NPCC), and ISO-NE. NPCC is one of eight regional entities under NERC. As the regional entity for Northeastern North America (that is, New England, New York and eastern Canada), NPCC sets rules and criteria particular to the Northeast. ISO-NE has also developed rules and criteria specific to New England.

The reliability standards address both local (Area Transmission Requirements) and regional (Transmission Transfer Capability) concerns. The Area Transmission Requirements specify that the transmission system be capable of delivering power to consumers under anticipated outage conditions. Transmission Transfer Capability addresses the need for the transmission system to be capable of transferring power within the ISO-NE region and between ISO-NE and its neighbors. The standards define the system conditions and contingencies that must be evaluated when performing a reliability assessment of the transmission grid.[2] These standards were incorporated in ICF's study.

As part of its regional transmission planning process, ISO-NE evaluates whether any areas within its footprint or border regions may violate NERC standards within the 10-year planning horizon. In the *2007 Regional System Plan*, ISO-NE highlighted concern over future reliability violations within Southern New England. Encompassing the states of Connecticut, Massachusetts and Rhode Island, Southern New England represents 80% of New England's load.[3] During the last 10 years, various drivers such as strong load growth and increased generation have begun to strain the existing transmission system in this region. Despite planned upgrades in key load pockets, local and regional reliability violations may occur as early as 2009.[4] Furthermore, local and regional reliability are often interrelated and "individual solutions in one area must be evaluated to ensure that they do not produce unintended consequences in another area."[5]

Given the complex and interdependent nature of the Southern New England transmission network and the long lead time needed to implement transmission solutions, ISO-NE explored this issue focusing on the system's reliability needs for 10 years from 2007 to 2016 with a focus on the summers of 2009 and 2016. ISO-NE created a reference case simulation for its analysis which included currently planned transmission upgrades expected to be online by 2009.[6] With increasing demand growth, the ISO-NE simulations identified violations of reliability criteria during the study horizon with respect to stability, steady state, and fault-current scenarios.[7] The results of these studies show that by 2009, "area transmission capabilities will be inadequate to meet NERC…reliability standards and criteria for the projected load and generation conditions in the Connecticut, Springfield, and Rhode Island areas."[8]

ISO-NE formed a working group which included National Grid, and Northeast Utilities to conduct the studies necessary to analyze the system upgrade options to the transmission problems identified in the 2007 RSP for the southern New England region. The studies show that by 2009, load deficits occur for Connecticut and Springfield even in normal operating conditions and for Rhode Island during emergency conditions. By 2016, however, deficits occur for all three areas during normal operating conditions.[9] A

[2] ISO New England Planning Procedure No. 3, Reliability Standards for the New England Area Bulk Power Supply System, October 13, 2006

[3] "Southern New England Transmission Reliability Report 1 Needs Analysis," January 2008, ISO New England, page 2.

[4] "Southern New England Transmission Reliability Report 1 Needs Analysis," January 2008, ISO New England, page 11.

[5] "Southern New England Transmission Reliability Report 1 Needs Analysis," January 2008, ISO New England, page ii.

[6] The Reference Case included the following planned transmission improvements: Southwest Connecticut Phase I and II Projects; Boston 345 kV Transmission Reliability Project; Northeast Reliability Interconnection Project; Northwest Vermont Reliability Projects; Central Massachusetts Reliability Projects; Southwest Rhode Island Reliability Projects; Barbour Hill Reliability Projects; and Killingly Reliability Project.

[7] The results of this analysis by ISO New England can be found in "Southern New England Transmission Reliability Report 1 Needs Analysis," January 2008.

[8] "Southern New England Transmission Reliability Report 1 Needs Analysis," January 2008, ISO New England, page 31.

[9] "Southern New England Transmission Reliability Report 1 Needs Analysis," January 2008, ISO New England, page 11.

load deficit is the amount of load unable to be served reliably because of transmission constraints.[10]

ISO-NE concludes that these deficits and the five weaknesses "demonstrate a need to construct new transmission facilities to significantly improve the reliability of the transmission grid serving Connecticut, Rhode Island, and western Massachusetts. Given the lead times necessary for permitting and other pre-construction activities, as well as the time required for construction itself, these problems constitute needs that should be addressed now."[11]

In a separate report, ISO-NE identified potential solutions and assessed each option based on system performance characteristics.[12]

III. Rhode Island Reliability Project

Rhode Island has only two 345-kV line connections to the New England 345-kV transmission system. Kent County Substation, a key Rhode Island load serving substation, has only one 345-kV line connecting to it. Additionally, Rhode Island has limited generation connected to the 115-kV system. This combination of limited 345-kV connections and limited generation connected to the 115 kV system makes Rhode Island vulnerable to line and equipment overloads and area voltage violations under contingency conditions (particularly for N-1-1 second contingency conditions).

The Rhode Island Reliability Project proposes the following reinforcements to address these reliability problems:

- A new 345- kV line from West Farnum Substation to Kent County Substation
- An additional 345/115-kV autotransformer at Kent County Substation
- Various transmission line upgrades and substation terminal equipment upgrades.

These upgrades would change the system configuration at Kent County Substation from one 345-kV line and two 345/115-kV autotransformers to a new configuration of two 345-kV lines and three 345/115-kV autotransformers.[13]

Additional support for the Rhode Island area is offered through a proposed new 345-kV line from Millbury #3 Substation to West Farnum Substation which is part of the NEEWS Interstate Reliability project. Though it is not directly included in the Rhode Island Reliability Project, when the two projects are combined, additional local Rhode Island benefits are anticipated.

[10] Note that references to Connecticut, Springfield and Rhode Island do not refer to state or city boundaries or coincide with definitions used by ISO New England for operational purposes. The names refer to areas specifically delineated for the above referenced needs analysis.
[11] "Southern New England Transmission Reliability Report 1 Needs Analysis," January 2008, ISO New England, page 31.
[12] The results of ISO New England's analysis are found in "New England East–West Solutions, Report 2, Options Analysis."
[13] There is one existing autotransformer and one planned outside of the Project additions. Together with the autotransformer included in the project, this will result in a total of three autotransformers by 2013.

Several upgrades to the current transmission system configuration are already in well advanced stages of planning or are under construction. Since these projects will certainly have an impact on the system in 2013[14], it was important to ensure that they were included in the analysis. The specific modifications included are:

- Install a 345/115-kV autotransformer and two 115-kV, 72-MVAR capacitors at Kent County Substation and reinforce the substation
- Make terminal upgrades at Drumrock Substation (I-187 & J-188)
- Reconductor a 115-kV line (T7) from Somerset, MA to Pawtucket, RI with terminal upgrades at Pawtucket Substation
- Upgrade 115-kV terminal equipment at West Farnum Substation
- Install a new 115-kV line from Brayton Point, MA to Somerset, MA
- Install a new 345/115-kV Substation in Plainville, MA.

IV. Analytical Approach and Key Assumptions

IV.1. <u>Assessment of Alternatives to Transmission under Reliability Planning</u>

Transmission lines and systems are designed to provide reliable power delivery from source to the distribution delivery point supporting the end-user. Reductions in end-use demand, or less centralized placement of generation may reduce the utilization of lines on the transmission system. In assessing the potential for alternative resources to displace or defer the Project, ICF considered three distinct options:

1. Combined Heat and Power Resources ("CHP"): These reflect the resources that would be located on site, typically at larger industrial or commercial locations with both steam and electric power needs, and would be used as the primary source of power for that location such that there is no direct demand from the location for regional generation sources and hence no demand for transmission services.

2. Demand-Side Management ("DSM") Resources: Demand-Side Management resources represent a large block of options that tend to reduce the demand for system generation and transmission services either through direct reductions in the load, or the addition of generation as a distributed source, i.e. distributed generation. Demand reductions may either be passive, such as energy efficiency programs that are tied to use of highly efficient equipment , or they may be active. Active resources reflect loads that can be responsive to system conditions or prices such as interruptible load contracts or distributed/emergency generators.

3. Generation: Generation resources located closer to the load demand centers may also help reduce the overall load on the transmission system.

These three options alone, or in combination have the potential to in some circumstances defer or displace upgrades to the existing transmission system while

[14] 2013 is the year used in the ICF power-flow analysis. This reflects the year that the facilities are expected to be in-service.

maintaining the same level of reliability. However, they may not offer the same certainty offered through transmission projects. For example, in order 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.

IV.2. Reliability Planning Criteria and Power-Flow Approach

The performance of the New England transmission system is governed by reliability standards and criteria established by NERC, the Northeast Power Coordinating Council, Inc. (NPCC), and the ISO-NE. Operating within these standards ensures that electric power customers in New England will be served with reliable electric power. Similar to the ISO-NE Southern New England Transmission Reliability study[15], ICF's study was designed to test the operation and reliability of the New England transmission system under these standards and criteria.

Both NPCC and ISO-NE standards establish that the electric transmission system must pass specific tests to comply with the established reliability criteria. These tests take into account historical data and occurrences and include an examination of Area Transmission Requirements and Transmission Transfer Capability.

Once the set of reasonable alternatives was established, the reliability assessment for the Rhode Island Reliability Project was carried out by comparing the performance of the local area and broader regional transmission system with and without the Project under various conditions. ICF modeled the New England transmission system under normal and emergency conditions for both cases. The emergency conditions tested included possible N-1 and N-1-1 contingency conditions and further considered the same contingencies under a generation stress case. The analysis was conducted for the year 2013 to coincide with the planned in-service date of the Project.

Chapter One provides additional details on the analytical approach to the alternatives assessment and power-flow modeling.

IV.3. Key Assumptions for the Alternatives Analysis

Combined Heat and Power Resources: The decision on the type of CHP resource to add and location of the resource was based on an assessment of technical potential and the economics of various CHP options. A review of the technical potential was conducted on a state level through assessing the potential locations which currently are not served by CHP sources. ICF utilized its own projections for forward market prices to assess the economics of the CHP options in combination with market surveys of the penetration rates for the equipment. The resulting additions in the state of Rhode Island were 31 MW of CHP.

[15] "Southern New England Transmission Reliability Report 1 Needs Analysis," January 2008, ISO New England.

Demand-Side Management Resources: ICF projected DSM savings based on publicly available projections for the maximum technically achievable DSM and the market information revealed through the ISO-NE Forward Capacity Auction (FCA) process. The FCA has been very successful at attracting demand resources in the New England market area. Roughly 2,500 MW of demand resources cleared in the first Forward Capacity Auction for 2010/2011. The second auction has yet to occur, but demand resources have already submitted to qualify to participate in that auction. The total of demand resources cleared in the first FCA and those showing interest in the second FCA is just over 4,200 MW. This total represents approximately 12% of the peak capacity requirement in the 2011/12 commitment period throughout New England. The Rhode Island resources that were selected in the 2010/2011 auction amounted to 165.4 MW or 8.5% of the expected Rhode Island state summer peak load in 2010. We assume that the total committed demand resources in Rhode Island will grow at the same rate as the technical potential found in other sources such as the January 2008 Connecticut IRP and the growth in resources submitting to the FCA between auction periods, which yields an annual growth rate of 17%. This assumed growth rate results in a total of 265 MW of peak DSM in Rhode Island in 2013 and a peak penetration of DSM resources of 15% of peak load in Rhode Island.

New Generation Assets: Supply-side resources were also reviewed to ensure that adequate supply was maintained for generation planning purposes. The options considered included traditional generation supply such as combined cycles, combustion turbines, fossil steam units, nuclear units, and renewable units. The decision on the type of resource necessary to add to maintain adequate reserves was based on a high level assessment of the economics of these options. The requirement that load-serving entities face in much of New England to satisfy renewable portfolio standard obligations was also considered in the decision. The resulting additions in the Rhode Island area were 196 MW of renewable generation.

As described above and analyzed, the total resources available as generation or demand side options were examined in combination to determine the total penetration of these resources under aggressive penetration assumptions. This approach resulted in a total amount of resource additions which were included in all cases. Another approach was also examined. This second approach considered the following question: Given the system in its existing configuration, what total amount of demand reductions would be necessary to achieve the benefits identified from the Project under the already assumed level of aggressive penetration?

IV.4. Key Assumptions for the Power-Flow Modeling

The starting point for the non-transmission alternatives analysis was the 2012 power-flow planning case from ISO-NE. This information was provided to ICF under confidentiality restrictions by Northeast Utilities so as to protect Critical Energy Infrastructure Information (CEII) in accordance with FERC requirements. Since the study year for the alternatives analysis was 2013, there were several modifications that were made to the case to reflect 2013 conditions. These modifications were reflected in both the pre- and post-project implementation cases and additional stressed generation scenarios.

The key assumptions for the power-flow modeling include:

- **Load Projections:** The original power-flow case provided was based on a 2006 vintage forecast for load growth. ISO-NE released a revised forecast in April 2008[16] which was adopted for purposes of this analysis. To modify the peak load input, the load at each node was scaled by the ratio of the 2006 and 2008 vintage forecasts. In compliance with standard transmission reliability planning methods, ICF used the extreme weather peak demand forecast (also known as the 90/10 forecast). Under the 90/10 forecast, the Rhode Island zonal peak demand is estimated to be 2,965 MW in 2013 based on the 2008 vintage forecast. The values used in the original power-flow were 2,940 MW for the 2012 year, nearly an identical match to the 2013 demand predicted by the current 2008 forecast. The same approach was applied to all areas within New England. Additional factors and assumptions affecting load projections include:

    - **Dispatchable DSM Resources:** For modeling purposes, the dispatchable DSM resources such as the emergency generators and demand response are assumed to be reserved for emergency conditions and are not removed from the ISO-NE peak load projection in the power-flow cases.[17] Thus, the Rhode Island peak load is only decremented by 113 MW to account for the non-dispatchable DSM resources for the power-flow analysis, accounting for about 43% of the total Rhode Island DSM projection. Since the ISO-NE load projections are at the generator level, load decrements for DSM include reserve margin requirements and transmission losses.

    - **Transmission Losses:** The ISO-NE load projections are based at the generator bus-bar and hence include both transmission and distribution losses. In contrast, power-flow load inputs reflect the load at the distribution transfer point rather than at the generator level. As such, we have adjusted the ISO-NE load projections to remove transmission losses to reflect the distribution load levels. This allows for the power-flow to internally determine the transmission sector losses.

- **Existing Generating Capacity:** ICF relied on the generation capacity for existing units as provided directly in the power-flow case. The capacity included in the power-flow case reflects the maximum summer-rated capacity for each unit. Modifications were then made to first establish a view of system dispatch under normal peak-day conditions such that system operations were not stressed for the Reference Case. Additional modifications were made to ensure that adequate supply resources were available to satisfy the expected realized peak load in 2013.

[16] "2008-2017 Forecast Report of Capacity, Energy, Loads, and Transmission," April 2008, ISO New England.
[17] ISO-NE views dispatchable DSM as supply side resources

- **Forced Outage Rate and Spinning Reserves:** From the dispatch perspective, forced outages and spinning reserves were accounted for in the dispatch. The forced outage rate assumed for Rhode Island was 7 percent of the total zonal capacity. To implement the forced outage in the power-flow model, ICF turned off selected generation units to reach 7 percent of the total capacity such that these units were assumed to not be available to meet system demand. The same forced outage rate assumption was used for each zone in New England. A spinning reserve requirement of approximately 15 percent of total capacity was also implemented in the power-flow model across New England. This represents generation capacity that is made available to respond to system contingencies and reflects roughly the largest generation contingency in each zone. The 15 percent spinning reserve was implemented in each load zone with the exception of the SEMA/Rhode Island area. Since the SEMA/Rhode Island area is a net exporting region, it is expected that all generation units within that area will be operating at their available capacities on a peak summer day.

- **Generation Asset Lifetime:** Assumptions regarding the useful life of existing generating assets were also made. ICF assumed that any non-hydro asset within New England that reached the age of 60 years by 2013 would retire. No generators in Rhode Island were affected by this retirement assumption.

V. Conclusions

Based on the results of the analysis performed for this study that included projected new generation, DSM, and CHP resources, the Rhode Island Reliability Project was determined to be critical to the reliable operation of the New England transmission grid, and in particular, the Rhode Island transmission system. Non-transmission alternatives to the Rhode Island Reliability Project were not found to be satisfactory or sufficient in nature to displace or defer the need for the Project. This conclusion is supported by results of the power-flow analysis which indicate that, despite the addition of generation, DSM, and CHP resources previously described, numerous transmission facility overloads and substation voltage violations could still potentially occur under contingency conditions.

This was evident in both the reference case, with generation facilities under normal operation, and the generation outage scenarios. The analysis further demonstrated that the transmission reinforcements from the Rhode Island Reliability project would improve the performance of the system in the area of study and resolve the line overloads and voltage violations.

It should be noted that these conclusions are based on conservative assumptions used to generate the Reference Case. Less conservative assumptions would result in greater line overloads and voltage violations than were determined in this study. The conservative nature of these assumptions is focused on both the supply and the demand side including the following:

- ISO-NE has an admitted history of under-forecasting peak demand. Based on studies conducted by the ISO itself, the average forecast error for the fifth year (the relevant year for our study) is biased to a 4.2% under estimate of peak.
  - This under-forecasting seems to be a continuing trend on its face given that the peak projections for the 2008 weather normal forecast are not only below the 2007 forecast but are well below the 2006 forecast as well.
- ICF's analysis under the Reference Case reflects a normal peak-day operation for the system assuming that adequate spinning reserves are maintained and further that no active demand resources are called on. These conditions do not reflect the standard which suggests that transmission planning be performed under stress conditions. ICF further examines several generation stress cases in comparison to the Reference Case.
- Several generation units in New England which have been targeted by environmental groups as high polluters and are considered somewhat at risk of closure based on tightening of environmental regulations have not been assumed to retire or turndown. These units include five plants in Connecticut and five in Massachusetts.[18, 19]
- ICF's assumed generation outages do not reflect the extreme generation outage conditions which have occurred on occasion in New England. Thus the equipment overloads and voltage violations found under ICF's cases can be reasonably expected to occur under such extreme conditions.

The conservative nature of these assumptions further reinforces the conclusions above given that even under these conservative assumptions, the reliability of the system must be addressed through the proposed transmission upgrade. The conservative nature of these assumptions is further elaborated on in Chapter One.

[18] The five Connecticut plants are Bridgeport Harbor, New Haven Harbor, Norwalk Harbor, Middletown, and Montville. The five plants in Massachusetts include Brayton Point, Salem Harbor, Canal, Mount Tom and Mystic. Brayton Point, though located in Massachusetts is electrically in the Rhode Island zone and is approximately 1100 MW.

[19] The conservative nature of this assumption is further supported by NRG's recent interrogatory response filed with the Connecticut Energy Advisory Board (CEAB), Docket F-2008 NRG Energy Inc.'s Responses to Interrogatories of the CEAB, dated July 8, 2008, in which NRG indicated that the retirement of Norwalk Harbor, Montville, and Middletown should be expected if prevailing market conditions continue.

CHAPTER ONE: OPTIONS FOR AND ASSESSMENT OF TRANSMISSION SYSTEM ALTERNATIVES

1.1 Rhode Island Reliability Project Background

Rhode Island has only two 345-kV line connections to the New England 345-kV transmission system. Kent County Substation, a key Rhode Island load serving substation, has only one 345-kV line connecting to it. Additionally, Rhode Island has limited generation connected to the 115-kV system. This combination of limited 345-kV connections and limited generation connected to the 115 kV system makes Rhode Island vulnerable to line and equipment overloads and area voltage violations under contingency conditions (particularly for N-1-1 second contingency conditions).

The Rhode Island Reliability Project proposes the following reinforcements to address these reliability problems:

- A new 345-kV line from West Farnum Substation to Kent County Substation
- An additional 345/115-kV autotransformer at Kent County Substation
- Various transmission line upgrades and substation terminal equipment upgrades.

These upgrades would change the system configuration at Kent County Substation from one 345-kV line and two 345/115-kV autotransformers to a new configuration of two 345-kV lines and three 345/115-kV autotransformers.

The Project is part of the larger New England East-West Solution (NEEWS) which, in addition to the Rhode Island Reliability Project, includes three other major transmission projects:

- Interstate Reliability Project
- Greater Springfield Reliability Project
- Central Connecticut Reliability Project

These four projects were selected in combination as the most effective approach to address major transmission system weaknesses which ISO New England (ISO-NE), the regional transmission organization (RTO) serving the New England electricity market, identified in its 2007 Regional System Plan[20]. The Rhode Island Reliability Project is designed specifically to alleviate Rhode Island's dependence on single transmission lines or autotransformers for reliability. However, there are significant synergies resulting from the combined implementation of the four NEEWs projects which further reinforce the transmission system. For example, additional support for the Rhode Island area is offered through a proposed new 345-kV line from Millbury #3 Substation to West Farnum Substation which is part of the NEEWS Interstate Reliability project. Though it is not directly included in the Rhode Island Reliability Project, when the two projects are combined, additional local Rhode Island benefits will be obtained.

[20] "2007 Regional System Plan," October 18, 2007, ISO New England.

ICF was retained by Northeast Utilities and National Grid, the sponsors of the NEEWS projects, to prepare an analysis considering the potential for alternative resources, on both the supply and demand side, to displace or defer the Rhode Island Reliability Project.

1.2 Options for Non-Transmission Alternatives to the Rhode Island Reliability Project

Transmission and distribution lines and systems are designed to provide reliable power delivery from source to end-user. As demand for electrical energy grows, utilization of a transmission system also grows and upgrades may be required to continue to serve load reliably over time. Alternatively, additional generation sources nearby the load demand areas, or reductions in the load at key demand areas may alleviate the load on the transmission system and help to defer or displace transmission upgrades otherwise necessary. In assessing the potential for alternative resources to displace or defer the Project, ICF considered three distinct options:

1. **Combined Heat and Power Resources:** These reflect the resources that would be located on site, typically at larger industrial or commercial locations with both steam and electric power needs, and would be used as the primary source of power for that location such that there would no longer be any direct demand from the location for regional generation sources and hence no demand for transmission services.
2. **Demand-Side Resources:** Demand-Side Management resources represent a large block of options that tend to reduce the demand for system generation and transmission services either through direct reductions in the load, or the addition of generation as a distributed source. Demand reductions may be passive, such as energy efficiency programs which may rely on replacing older less efficient equipment with newer more efficient equipment. In this case, all else equal, to provide the same function from the equipment, less energy would be consumed. Demand resources may also be active resources. Active resources reflect loads such as interruptible load contracts that can be responsive to system conditions or prices. Additionally, distributed or emergency generators are considered responsive demand resources in this analysis.
3. **Generation:** Generation resources located closer to the load demand centers may also help reduce the overall load on the transmission system. Local generation sources will help reduce the transmission load provided that they are appropriately sized and that they are operating at the time of need. It should be noted that a generator that is sized too large may have an undesired effect through creating additional constraints in trying to move generation in the opposite direction of traditional flows and hence impacting the overall system directional flows and utilization. So although they may help alleviate a constraint in one area, generation resources may result in constraints in other areas.

These three options alone, or in combination have the potential to, in some circumstances, defer or displace the need for upgrades to the existing transmission system while maintaining the same level of reliability. However, the benefits from transmission upgrades in terms of reliability are likely to be much more reliable and dependable than any of the options. Outages on the transmission system tend to be shorter than that of generation assets when both types of facilities are adequately maintained, and in particular are less frequent than distributed generation options. Even more so, the reliability benefits of the savings from demand resources are much less predictable than the benefits of generation or transmission options. The duration of active demand-side resources tends to be somewhat short-lived, such that if the transmission system overloads are greater than 3 to 5 hours, the demand resources may no longer be available. Further, transmission provides additional benefits beyond strict reliability considerations such as helping to reduce losses and also helping to move ouput from lower cost resources located in non-local areas to the local demand centers. Such additional benefits may not be available from the non-transmission alternatives.

1.3 Approach to Considering Non-Transmission Alternatives to the Rhode Island Reliability Project

In order to assess the potential for CHP, DSM, or generation options to defer or displace the Project in 2013, ICF considered the potential for each separately. The evaluation first considered the potential for CHP resources and DSM resources in isolation from each other. Once this was determined, ICF considered the potential for generation resources. Each of these analyses is described in detail in the chapters which follow. In summary, the expected potential in each of these areas based on both the technical potential and the economic potential were considered. Once these data were estimated, the expected resource potential was input into a power-flow case for 2013. Assuming that these resources were available, we examined if a reliability need established by ISO-NE in their transmission planning process continued to exist. Additionally, ICF used a second approach in which we examined the total load reduction that would be necessary to achieve the same or similar reliability levels as exist with the Project. That is, within a power-flow case which did not contain the upgrades associated with the Project, the load levels were decremented until a reasonably close reliability level to that of the Project was achieved.

1.4 Approach to Power-Flow Reliability Analysis

Power-flow studies are important in the operation and planning of the transmission grid. The studies are based on detailed models of the power system that include representations of generation units, load, transmission facilities, substations and other components. Computer simulations using powerful software models are then used to determine the performance of the system under various conditions. The results of such simulations include power flows or loading on transmission lines, dispatch of generation units, and voltages at substations. Power-flow simulations can be used to analyze variations in system performance due to changes in configuration. For example, in

ICF's study, simulations were used to determine how the power flowing on transmission lines would change if other key transmission lines were taken out of service.

ICF's study was designed to test the operation of the New England transmission system under the ISO-NE standards and criteria, which require that the system reliably continue to serve its load during anticipated transmission facility outages. The standards and criteria also require that the New England transmission system maintain adequate capability to transfer power within New England and between New England and neighboring markets.

The reliability assessment for the Project was carried out by comparing the performance of two separate configurations of the New England regional transmission system. The first case, referred to as the Pre-RIRP Case, represents the New England transmission system assuming the Project, as well as the other components of the NEEWS, is not implemented. The second case, referred to as the Rhode Island Case represents the transmission system assuming the Project was implemented. Both cases were developed from power-flow models of the New England transmission system and were representative of a summer peak demand period in 2013.

To determine the ability of the system to continue to serve its load during anticipated facility outages, ICF performed a detailed power-flow analysis of the system assuming both normal and emergency conditions. Normal conditions imply that all generation and transmission facilities continue to operate as expected on a peak summer day. First, ICF assessed system performance under normal conditions assuming no unplanned failure of a transmission element such as a transmission line, a transformer, a circuit breaker, or a pair of transmission lines on a multiple circuit transmission tower. Next, the process was repeated for the unexpected failure of key transmission elements.

A similar analysis was then conducted to evaluate system performance under emergency conditions, that is, following the outage of a single transmission element a second element was then considered to fail. In this analysis, the transmission system was first allowed to adjust the flows of power following the single element loss.

System performance was measured by monitoring transmission lines for overloads, and transmission substations for voltage violations. To continue to operate reliably, the power-flowing on each transmission line should remain below the emergency ratings of the line. If a line exceeds its limit, operator action may be taken to relieve the overload; if the overload persists, protective devices in the network may activate to take the line out of service in order to prevent damage to the line. Emergency actions taken by operators or automatic measures to relieve one line's overload could overload other transmission system elements, worsen system conditions, and result in severe power outages or a blackout. It is therefore important to ensure that the system is designed to operate within limits under anticipated emergencies. Similarly, substation voltages must remain within acceptable limits specified by the operator.

Furthermore, ICF assessed the ability of the system to operate reliably if selected generation facilities in the study area were out of service. In each case a generation unit was taken out of service and other generation facilities adjusted to replace the lost output. The performance of the system was then examined as described above.

The loss of a single transmission element is referred to as an N-1 contingency. The loss of a single transmission component followed by the loss of a second component is referred to as N-1-1 contingency.

A detailed discussion of the power-flow cases and input assumptions is provided in Chapter Five.

CHAPTER TWO: COMBINED HEAT AND POWER RESOURCE ALTERNATIVES

Combined Heat and Power ("CHP") resources reflect the resources that would be located on site, typically at larger industrial or commercial locations with both steam and electric power needs, and would be used as the primary source of power for that location such that there would no longer be any direct demand from the location for regional generation sources and hence no demand for transmission services.

The potential for CHP resources in New England was determined as a multi-step process which included first assessing the technical potential, then assessing the economic break-even point, and finally assessing the market penetration based on user adoption rates and economics.

- o *Technical potential* represents the total capacity potential from existing and new facilities that are likely to have the appropriate physical electric and thermal load characteristics that would support a CHP system with high levels of thermal utilization during business operating hours.

- o *Economic potential* reflects the share of the technical potential capacity (i.e. the customer base) that would consider the CHP investment economically acceptable according to a procedure that is described in more detail below.

- o *Cumulative market penetration* represents an estimate of CHP capacity that will actually enter the market between 2008 and 2023. This value discounts the economic potential to reflect non-economic screening factors and the rate that CHP is likely to actually enter the market.

A detailed discussion of each step is provided below.

2.1 Technical Potential for CHP

The technical potential for CHP is considered in three broad sectors: 1) industrial, 2) commercial/institutional, and 3) multi-family residential. Two different types of CHP market segments were included in the evaluation of technical potential. Both were evaluated for high load factor (80% and above) and low load factor (51%) applications resulting in four distinct market segments that are analyzed. These markets are considered individually because both the annual load factor and the installation and operation of thermally activated cooling has an impact on the system economics.

- o **Traditional CHP** – electric output is produced to meet all or a portion of the base load for a facility and the thermal energy is used to provide steam or hot water. Depending on the type of facility, the appropriate sizing could be either electric or thermal limited. Industrial facilities often have "excess" thermal load compared to their on-site electric load. Commercial facilities almost always have excess electric load compared to their thermal load. Two sub-categories were considered:

- **High load factor applications** – This market provides for continuous or nearly continuous operation. It includes all industrial applications and round-the-clock commercial/institutional operations such as colleges, hospitals, hotels, and prisons.

- **Low load factor applications** – Some commercial and institutional markets provide an opportunity for coincident electric/thermal loads for a period of 3,500 to 5,000 hours per year. This sector includes applications such as office buildings, schools, and laundries.

o **Combined Cooling Heating and Power (CCHP)** – All or a portion of the thermal output of a CHP system can be converted to air conditioning or refrigeration with the addition of a thermally activated cooling system. This type of system can potentially open up the benefits of CHP to facilities that do not have the year-round thermal load to support a traditional CHP system. A typical system would provide the annual hot water load, a portion of the space heating load in the winter months and a portion of the cooling load during the summer months. Two sub-categories were considered:

- **Low load factor applications** – These represent markets that otherwise could not support CHP due to a lack of thermal load.

- **Incremental high load factor applications** – These markets represent round-the-clock commercial/institutional facilities that could support traditional CHP, but with cooling, incremental capacity could be added while maintaining a high level of utilization of the thermal energy from the CHP system. All of the market segments in this category are also included in the high load factor traditional market segment, so only the incremental capacity for these markets is added to the overall totals.

The following basic steps were used to estimate the technical potential in these sectors for the four types of CHP segments:

1. **Identify applications where CHP provides a reasonable fit to the electric and thermal needs of the user.** Target applications were identified based on reviewing the electric and thermal energy (heating and cooling) consumption data for various building types and industrial facilities. Data sources include the DOE EIA *Commercial Buildings Energy Consumption Survey (CBECS),* the DOE *Manufacturing Energy Consumption Survey (MECS)* and various market summaries developed by DOE, Gas Technology Institute (GTI), and the American Gas Association. Existing CHP installations in the commercial/institutional and industrial sectors were also reviewed to understand the required profile for CHP applications and to identify target applications.

2. **Quantify the number and size distribution of target applications.** Once applications that could technically support CHP were identified, the iMarket, Inc. *MarketPlace Database* and the *Major Industrial Plant Database* (MIPD) from His

Inc.[21] were utilized to identify potential CHP sites by Standard Industrial Classification (SIC) code or application, and location (county). The SIC code is a United States government system for classifying industries by a four-digit code. The *MarketPlace Database* is based on the Dun and Bradstreet financial listings and includes information on economic activity (8 digit SIC), location (metropolitan area, county, electric utility service area, state) and size (employees) for commercial, institutional and industrial facilities. In addition, for select SICs limited energy consumption information (electric and gas consumption, electric and gas expenditures) is provided based on data from Wharton Econometric Forecasting (WEFA). MIPD has detailed energy and process data for 16,000 of the largest energy-consuming industrial plants in the United States. The *MarketPlace Database* and MIPD were used to identify the number of facilities in target CHP applications and to group them into size categories based on average electric demand in kiloWatt-hours.

3. **Estimate CHP potential in terms of MW capacity.** Total CHP potential was then derived for each target application based on the number of target facilities in each size category. It was assumed that the CHP system would be sized to meet the average site electric demand for the target applications unless thermal loads (heating and cooling) limited electric capacity. There are two distinct applications and two levels of annual load making for four market segments in all. In traditional CHP, the thermal energy is recovered and used for heating, process steam, or hot water. In cooling CHP, the system provides both heating and cooling needs for the facility. High load factor applications operate at 80% load factor and above; low load factor applications operate at an assumed average of 4500 hours per year (51%) load factor. The high load factor cooling applications are also applications for traditional CHP, though the cooling applications have 25-30% more capacity than traditional. These differences are directly accounted for in the analysis.

4. **Estimate the growth of new facilities in the target market sectors**. The technical potential included economic projections for growth through 2023 by means of state by state 15-year growth factors. The growth factors used in the analysis for growth between the present and 2023 by individual sector are shown in Exhibit 2-1. These growth projections were used in this analysis as an estimate of the growth in new facilities. In cases where an economic sector is declining, it was assumed that no new facilities would be added to the technical potential for CHP. Note, existing CHP is subtracted from the identified sites to determine the remaining incremental technical market potential.

[21] IHS (NYSE: IHS) is a leading global source of energy, product lifecycle management, environmental and security information.

Exhibit 2-1
New England State CHP Growth Projections Through 2023

State	15 year average annual growth
CT	1.193%
MA	1.028%
ME	1.367%
NH	1.834%
RI	1.153%
VT	1.217%

The technical market potential does not consider screening for economic rate of return, or other factors such as ability to retrofit, owner interest in applying CHP, capital availability, natural gas availability, and variation of energy consumption within customer application/size class. The technical potential as outlined is useful in understanding the potential size and size distribution of the target CHP markets in the state. The estimated technical potential by county and size of unit is provided in Exhibit 2-2.

Exhibit 2-2
Rhode Island CHP Technical Potential by County and Size of Unit, 2013

	Size Range Capacity Totals (MW)					
County	**50-500 kW**	**500-1 MW**	**1-5 MW**	**5-20 MW**	**>20 MW**	**Total**
Bristol	4.9	10.2	5.8	0.0	0.0	21.0
Kent	18.3	24.2	24.1	0.0	61.3	127.9
Newport	11.5	13.2	10.9	0.0	0.0	35.6
Providence	58.0	105.7	134.1	39.9	23.9	361.6
Washington	15.0	19.9	13.2	21.2	0.0	69.2
Total	107.7	173.3	188.1	61.0	85.3	615.3

2.2 Economic Potential for CHP

Economic potential is determined by an evaluation of the competitiveness of CHP versus purchased fuel and electricity. The projected future fuel and electricity prices and the cost and performance of CHP technologies determine the economic competitiveness of CHP in each market. CHP technology and performance assumptions appropriate to each size category and region were selected to represent the competition in that size range (Exhibit 2-3). Additional assumptions were made for the competitive analysis. Technologies below 1 MW in electrical capacity are assumed to have an economic life of 10 years. Larger systems are assumed to have an economic life of 15 years. Capital related amortization costs were based on a 10% discount rate. Based on their operating characteristics (each category and each size bin within the category have specific assumptions about the annual hours of CHP operation (80-90% for the high load factor cases with appropriate adjustments for low load factor facilities), the share of recoverable thermal energy that gets utilized (80%-90%), and the share of useful thermal energy that is used for cooling compared to traditional heating. The economic figure-of-merit chosen to reflect this competition in the market penetration model is simple payback.[22] While not the most sophisticated measure of a project's performance, it is nevertheless widely understood by all classes of customers.

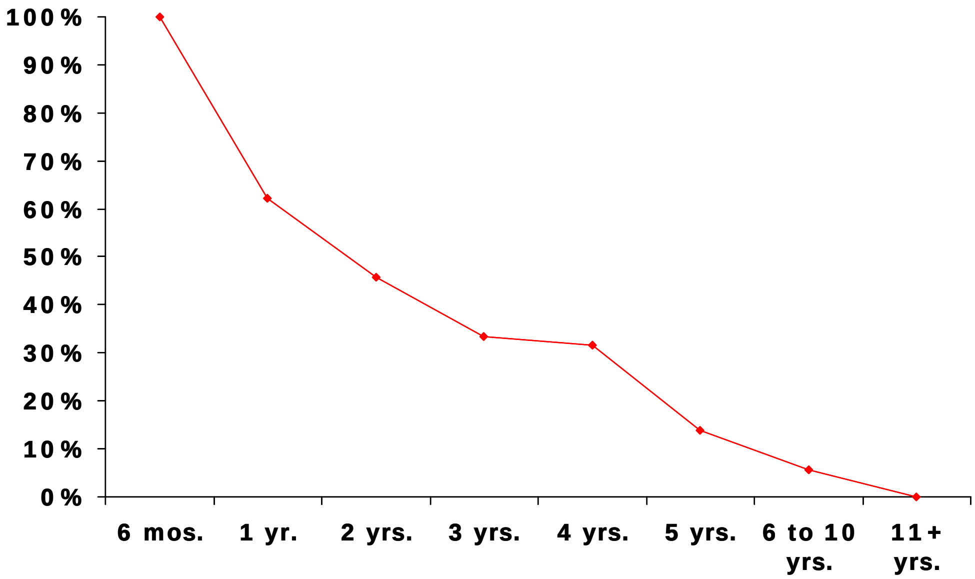
Exhibit 2-3
Technology Competition Assumed within Each CHP Size Category

Market Size Bins	Competing Technologies
50 – 500 kW	100 kW Recip Engine
	70 kW Microturbine
	150 kW PEM Fuel Cell
500 - 1,000 kW	300 kW Recip Engine (multiple units)
	70 kW Microturbine (multiple units)
	250 kW MC/SO Fuel Cell (multiple units)
1 – 5 MW	3 MW Recip Engine
	3 MW Gas Turbine
	2 MW MC Fuel Cell
5 - 20 MW	5 MW Recip Engine
	5 MW Gas Turbine
20 – 100 MW	40 MW Gas Turbine

Rather than use a single payback value, such as 3-years or 5-years as the determinant of economic potential, we have based the market acceptance rate on a survey of commercial and industrial facility operators concerning the payback required for them to consider installing CHP. Exhibit 2-4 shows the percentage of survey respondents that would accept CHP investments at different payback levels[23]. As can be seen from the figure, more than 30% of customers would reject a project that promised to return their initial investment in just one year. A little more than half would reject a project with a payback of 2 years. This type of payback translates into a project with an ROI of between 49-100%. One possible explanation for rejecting a project with such high returns is that the average customer does not believe that the results are real and is protecting himself from this perceived risk by requiring very high projected returns before a project would be accepted. Another possible explanation is that the facility is very capital limited and is rationing its capital raising capability for higher priority projects (market expansion, product improvement, etc.).

[22] Simple payback is the number of years that it takes for the annual operating savings to repay the initial capital investment.
[23] "Assessment of California CHP Market and Policy Options for Increased Penetration", California Energy Commission, July, 2005.

Exhibit 2-4
Customer Payback Acceptance Curve



Source: *Primen's 2003 Distributed Energy Market Survey*

For each market segment, the economic potential represents the technical potential multiplied by the share of customers that would accept the payback calculated in the economic competition module.

ICF considered 2 cases for economic penetration, the first assumed existing active state incentives continued to be in place going forward while the second case applied incentives throughout New England.[24] The results of the economic potential for CHP in Rhode Island for each case are shown in Exhibit 2-5.

Exhibit 2-5
Rhode Island Economic Potential for CHP Resources by Size, 2013

Case	50-500 kW	500kW-1,000kW	1-5 MW	5-20 MW	>20 MW	All Sizes
	(MW)					
Base Incentive Case	4	9	51	24	41	130
High Incentive Case	11	32	86	38	41	208

Detailed discussions of the assumptions driving the economic analysis are presented below. The primary drivers of the economic analysis are the electric prices and gas prices that the equipment installation would avoid, and the equipment cost itself.

[24] Currently Connecticut offers a $400-500 per customer incentive. Rhode Island does not have an active incentive program.

2.2.1 Electric Prices

- Initial year price estimates are from EIA average retail price by state. Each additional year is calculated using the output of the ICF Integrated Planning Model™ (IPM®) model generation weighted industrial prices and then modified as described below for use in the CHP market penetration model. The industrial average prices for each 5-year period are shown in Exhibit 2-6.

- The electricity price assumptions for the high load factor CHP applications were as follows

  - 50-500 kW – 115% of the industrial average price
  - 500-1000 kW – Industrial average price
  - 1-5 MW – 90% of industrial average price (to reflect higher voltages and lower prices as customer size increases above the average industrial size used by EIA)
  - 5-20 MW – 81% of industrial average price
  - >20 MW – 81% of industrial average price

- Price adjustments for customer load factor were defined as follows:

  - High load factor – 90% of the estimated value
  - Low load factor – 100% of the estimated value
  - Peak cooling load – 150% of the estimated value

- For a customer generating a portion of its own power with CHP, standby charges are estimated at 15% of the defined average electric rate except for Connecticut where standby charges are waived as part of an ongoing incentive program. In the other New England states, when considering CHP, only 85% of a customer's rate can be avoided.

Exhibit 2-6
Input Price Forecast: Industrial Electric Price Estimation

Average Industrial Price	5 Year Average Prices $/kWh		
	2013	2018	2023
CT	$0.114	$0.106	$0.116
MA	$0.128	$0.119	$0.132
ME	$0.087	$0.081	$0.089
NH	$0.114	$0.106	$0.118
RI	$0.123	$0.114	$0.127
VT	$0.081	$0.075	$0.084

2.2.2 Natural Gas Prices

- The natural gas price assumptions are based on the forecast for delivered ISO-NE prices by state with estimated markups for other markets.

- Electric Sector and CHP price – equal to the ISO-NE 5-year average price for each state and 5-year time period
- Commercial Customer – -- $1.10/MMBtu (boiler fuel) above ISO-NE price
- Industrial Customer from City Gate -- $0.60/MMbtu (boiler fuel) above ISO-NE price

- The gas price assumptions are shown in Exhibit 2-7.

Exhibit 2-7
Natural Gas Price Assumptions ($/MMBtu)

Year	2013			2018			2023		
State	EG/ CHP	Ind.	Comm.	EG/ CHP	Ind.	Comm.	EG/ CHP	Ind.	Comm.
CT	$8.09	$8.69	$9.19	$7.24	$7.84	$8.34	$7.84	$8.44	$8.94
MA	$8.09	$8.69	$9.19	$7.24	$7.84	$8.34	$7.84	$8.44	$8.94
ME	$8.28	$8.88	$9.38	$7.43	$8.03	$8.53	$8.04	$8.64	$9.14
NH	$8.20	$8.80	$9.30	$7.35	$7.95	$8.45	$7.96	$8.56	$9.06
RI	$8.09	$8.69	$9.19	$7.24	$7.84	$8.34	$7.84	$8.44	$8.94
VT	$8.13	$8.73	$9.23	$7.27	$7.87	$8.37	$7.88	$8.48	$8.98

2.2.3 CHP Technology Cost and Performance

The CHP system itself is the engine that drives the economic savings. The cost and performance characteristics of CHP systems determine the economics of meeting the site's electric and thermal loads. A representative sample of commercially and emerging CHP systems was selected to profile performance and cost characteristics in combined heat and power (CHP) applications. The selected systems range in capacity from approximately 100 – 20,000 kW. The technologies include gas-fired reciprocating engines, gas turbines, microturbines and fuel cells. The appropriate technologies were allowed to compete for market share in the penetration model. In the smaller market sizes, reciprocating engines competed with microturbines and fuel cells. In intermediate sizes (1 to 20 MW), reciprocating engines competed with gas turbines.

Cost and performance estimates for the CHP systems were based on work being undertaken for the EPA.[25] The foundation for these updates is based on work previously conducted for NYSERDA[26], on peer-reviewed technology characterizations that ICF[27] developed for the National Renewable Energy Laboratory[28] and on follow-on

[25] EPA CHP Partnership Program, Technology Characterizations, December 2007 (under review).
[26] *Combined Heat and Power Potential for New York State*, Energy Nexus Group (later became part of EEA), for NYSERDA, May 2002.
[27] ICF's Energy and Environmental Analysis (EEA) group.
[28] "Gas-Fired Distributed Energy Resource Technology Characterizations", NREL, November 2003, http://www.osti.gov/bridge

work conducted by DE Solutions for Oak Ridge National Laboratory.[29] Additional emissions characteristics and cost and performance estimates for emissions control technologies were based on ongoing work conducted for EPRI.[30] Data is presented for a range of sizes that include basic electrical performance characteristics, CHP performance characteristics (power to heat ratio), equipment cost estimates, maintenance cost estimates, emission profiles with and without after-treatment control, and emissions control cost estimates. The technology characteristics are presented for three years: 2005, 2010, 2020. The 2007-2010 estimates are based on current commercially available and emerging technologies. The cost and performance estimates for 2010-2015 and 2015-2020 reflect current technology development paths and currently planned government and industry funding. These projections were based on estimates included in the three references mentioned above. NOx, CO and VOC emissions estimates in lb/MWh are presented for each technology both with and without aftertreatment control (AT). Which system is applicable in any size category (e.g., with aftertreatment or without) is a function of the specific emissions requirements assumptions for each scenario. The installed costs in the following technology performance summary tables are based on typical national averages.

Exhibits 2-8 through 2-11 show the CHP technology cost and performance assumptions. For the cooling markets an additional amount is added to cover the cost of absorption chillers. This cost is a fitted function based on the amount of heat available that varies from $50/kW for the large systems to over $500/kW for the smallest systems analyzed.

[29] "Clean Distributed Generation Performance and Cost Analysis", DE Solutions for ORNL. April 2004.
[30] "Assessment of Emerging Low-Emissions Technologies for Distributed Resource Generators", EPRI, January 2005.

Exhibit 2-8
Reciprocating Engine Cost and Performance Characteristics

CHP System	Characteristic/Year Available	2007-2010	2010-2015	2016-2020
100 kW	Installed Costs, $/kW	$2,210	$1,925	$1,568
	Heat Rate, Btu/kWh	12,000	10,830	10,500
	Electric Efficiency, %	28.4%	31.5%	32.5%
	Thermal Output, Btu/kWh	6100	5093	4874
	O&M Costs, $/kWh	0.022	0.013	0.012
	NO_x Emissions, lbs/MWh (w/ AT)	0.10	0.15	0.15
	CO Emissions w/AT, lb/MWh	0.32	0.60	0.30
	VOC Emissions w/AT, lb/MWh	0.10	0.09	0.05
	PMT 10 Emissions, lb/MWh	0.11	0.11	0.11
	SO_2 Emissions, lb/MWh	0.0068	0.0064	0.0062
	After-treatment Cost, $/kW	incl.	incl.	incl.
800 kW	Installed Costs, $/kW	$1,640	$1,443	$1,246
	Heat Rate, Btu/kWh	9,760	9,750	9,225
	Electric Efficiency, %	35.0%	35.0%	37.0%
	Thermal Output, Btu/kWh	2313	3791	3250
	O&M Costs, $/kWh	0.013	0.01	0.009
	NO_x Emissions, lbs/MWh (w/ AT)	0.5	1.24	0.93
	CO Emissions w/AT, lb/MWh	1.87	0.45	0.31
	VOC Emissions w/AT, lb/MWh	0.47	0.05	0.05
	PMT 10 Emissions, lb/MWh	0.10	0.01	0.01
	SO_2 Emissions, lb/MWh	0.0068	0.0057	0.0054
	After-treatment Cost, $/kW	300	190	140
3000 kW	Installed Costs, $/kW	$1,130	$1,100	$1,041
	Heat Rate, Btu/kWh	9,492	8,750	8,325
	Electric Efficiency, %	35.9%	39.0%	41.0%
	Thermal Output, Btu/kWh	3510	3189	2982
	O&M Costs, $/kWh	0.011	0.0083	0.008
	NO_x Emissions, lbs/MWh (w/ AT)	1.52	1.24	0.775
	CO Emissions w/AT, lb/MWh	0.78	0.31	0.31
	VOC Emissions w/AT, lb/MWh	0.34	0.10	0.10
	PMT 10 Emissions, lb/MWh	0.01	0.01	0.01
	SO_2 Emissions, lb/MWh	0.0057	0.0051	0.0049
	After-treatment Cost, $/kW	200	130	100
5000 kW	Installed Costs, $/kW	$1,130	$1,099	$1,038
	Heat Rate, Btu/kWh	8,758	8,325	7,935
	Electric Efficiency, %	39.0%	41.0%	43.0%
	Thermal Output, Btu/kWh	3046	2797	2605
	O&M Costs, $/kWh	0.009	0.008	0.008
	NO_x Emissions, lbs/MWh (w/ AT)	1.55	1.24	0.775
	CO Emissions w/AT, lb/MWh	0.75	0.31	0.31
	VOC Emissions w/AT, lb/MWh	0.22	0.10	0.10
	PMT 10 Emissions, lb/MWh	0.01	0.01	0.01
	SO_2 Emissions, lb/MWh	0.0054	0.0049	0.0047
	After-treatment Cost, $/kW	150	115	80

Exhibit 2-9
Microturbine Cost and Performance Characteristics

CHP System	Characteristic/Year Available	2007-2010	2010-2015	2016-2020
60 kW	Installed Costs, $/kW	$2,739	$2,037	$1,743
	Heat Rate, Btu/kWh	13,891	12,500	11,375
	Electric Efficiency, %	24.6%	27.3%	30.0%
	Thermal Output, Btu/kWh	6308	3791	3102
	O&M Costs, $/kWh	0.022	0.016	0.012
	NO_x Emissions, lbs/MWh (w/ AT)	0.15	0.14	0.13
	CO Emissions w/AT, lb/MWh	0.24	0.22	0.20
	VOC Emissions w/AT, lb/MWh	0.03	0.03	0.02
	PMT 10 Emissions, lb/MWh	0.22	0.20	0.19
	SO_2 Emissions, lb/MWh	0.0079	0.0074	0.0067
	After-treatment Cost, $/kW			
250 KW	Installed Costs, $/kW	$2,684	$2,147	$1,610
	Heat Rate, Btu/kWh	13,080	11,750	10,825
	Electric Efficiency, %	2.6%	29.0%	31.5%
	Thermal Output, Btu/kWh	4800	3412	2625
	O&M Costs, $/kWh	0.015	0.013	0.012
	NO_x Emissions, lbs/MWh (w/ AT)	0.43	0.24	0.13
	CO Emissions w/AT, lb/MWh	0.26	0.26	0.24
	VOC Emissions w/AT, lb/MWh	0.03	0.03	0.02
	PMT 10 Emissions, lb/MWh	0.18	0.18	0.16
	SO_2 Emissions, lb/MWh	0.0070	0.0069	0.0064
	After-treatment Cost, $/kW	500	200	90

Exhibit 2-10
Fuel Cell Cost and Performance Characteristics

CHP System	Characteristic/Year Available	2007-2010	2010-2015	2016-2020
200 kW PAFC in 2005 150 kW PEMFC in outyears	Installed Costs, $/kW	$6,310	$4,782	$3,587
	Heat Rate, Btu/kWh	9,480	9,480	8,980
	Electric Efficiency, %	36.0%	36.0%	38.0%
	Thermal Output, Btu/kWh	4250	3482	3281
	O&M Costs, $/kWh	0.038	0.017	0.015
	NO_x Emissions, lbs/MWh (w/ AT)	0.06	0.05	0.04
	CO Emissions w/AT, lb/MWh	0.07	0.07	0.07
	VOC Emissions w/AT, lb/MWh	0.01	0.01	0.01
	PMT 10 Emissions, lb/MWh	0.00	0.00	0.00
	SO_2 Emissions, lb/MWh	0.0057	0.0056	0.0053
	After-treatment Cost, $/kW	n.a.	n.a.	n.a.
300 kW MCFC	Installed Costs, $/kW	$5,580	$4,699	$3,671
	Heat Rate, Btu/kWh	8,022	7,125	6,920
	Electric Efficiency, %	42.5%	47.9%	49.3%
	Thermal Output, Btu/kWh	1600	1723	1602
	O&M Costs, $/kWh	0.035	0.02	0.015
	NO_x Emissions, lbs/MWh (w/ AT)	0.1	0.05	0.04
	CO Emissions w/AT, lb/MWh	0.07	0.05	0.04
	VOC Emissions w/AT, lb/MWh	0.01	0.01	0.01
	PMT 10 Emissions, lb/MWh	0.00	0.00	0.00
	SO_2 Emissions, lb/MWh	0.0057	0.0042	0.0041
	After-treatment Cost, $/kW	n.a.	n.a.	n.a.
1200 kW MCFC	Installed Costs, $/kW	$5,250	$4,523	$3,554
	Heat Rate, Btu/kWh	8,022	7,110	6,820
	Electric Efficiency, %	42.5%	48.0%	50.0%
	Thermal Output, Btu/kWh	1583	1706	1503
	O&M Costs, $/kWh	0.032	0.019	0.015
	NO_x Emissions, lbs/MWh (w/ AT)	0.05	0.05	0.04
	CO Emissions w/AT, lb/MWh	0.04	0.04	0.03
	VOC Emissions w/AT, lb/MWh	0.01	0.01	0.01
	PMT 10 Emissions, lb/MWh	0.00	0.00	0.00
	SO_2 Emissions, lb/MWh	0.0044	0.0042	0.0040
	After-treatment Cost, $/kW	n.a.	n.a.	n.a.

Exhibit 2-11
Gas Turbine Cost and Performance Characteristics

CHP System	Characteristic/Year Available	2007-2010	2010-2015	2016-2020
3000 KW GT	Installed Costs, $/kW	$1,690	$1,560	$1,300
	Heat Rate, Btu/kWh	13,100	12,650	11,200
	Electric Efficiency, %	26.0%	27.0%	30.5%
	Thermal Output, Btu/kWh	5018	4489	4062
	O&M Costs, $/kWh	0.0074	0.0065	0.006
	NOx Emissions, lbs/MWh (w/ AT)	0.68	0.38	0.2
	CO Emissions w/AT, lb/MWh	0.55	0.53	0.47
	VOC Emissions w/AT, lb/MWh	0.03	0.03	0.02
	PMT 10 Emissions, lb/MWh	0.21	0.20	0.18
	SO_2 Emissions, lb/MWh	0.0070	0.0069	0.0069
	After-treatment Cost, $/kW	210	175	150
10 MW GT	Installed Costs, $/kW	$1,298	$1,342	$1,200
	Heat Rate, Btu/kWh	11,765	10,800	9,950
	Electric Efficiency, %	29.0%	31.6%	34.3%
	Thermal Output, Btu/kWh	4674	4062	3630
	O&M Costs, $/kWh	0.007	0.006	0.005
	NO_x Emissions, lbs/MWh (w/ AT)	0.67	0.37	0.2
	CO Emissions w/AT, lb/MWh	0.50	0.46	0.42
	VOC Emissions w/AT, lb/MWh	0.02	0.02	0.02
	PMT 10 Emissions, lb/MWh	0.20	0.18	0.17
	SO_2 Emissions, lb/MWh	0.0069	0.0064	0.0059
	After-treatment Cost, $/kW	140	125	100
40 MW GT	Installed Costs, $/kW	$972	$944	$916
	Heat Rate, Btu/kWh	9,220	8,865	8,595
	Electric Efficiency, %	37.0%	38.5%	39.7%
	Thermal Output, Btu/kWh	3189	3019	2892
	O&M Costs, $/kWh	0.004	0.004	0.004
	NO_x Emissions, lbs/MWh (w/ AT)	0.55	0.2	0.1
	CO Emissions w/AT, lb/MWh	0.04	0.04	0.04
	VOC Emissions w/AT, lb/MWh	0.01	0.01	0.01
	PMT 10 Emissions, lb/MWh	0.16	0.15	0.15
	SO_2 Emissions, lb/MWh	0.0054	0.0052	0.0051
	After-treatment Cost, $/kW	90	75	40

2.3 Market Penetration Analysis

ICF has developed a CHP market penetration model that estimates cumulative CHP market penetration in 5-year increments. For this analysis, the forecast periods are 2013, 2018, and 2023. The target market is comprised of the facilities that make up the economic market potential. Based on this calculated economic potential, a market diffusion model is used to determine the cumulative market penetration for each 5-year time period.

The estimation of market penetration includes both a non-economic screening factor and a factor that estimates the rate of market penetration (diffusion.) The non-economic screening factor was applied to reflect the share of each market size category (i.e., applications of 50 to 500 kW, applications of 500 to 1,000 kW, etc) within the economic potential that would be willing and able to consider CHP at all. These factors range from 32% in the smallest size bin (50-500 kW) to 64% in the largest size bin (more than 20 MW.) These factors are intended to take the place of a much more detailed screening that would eliminate customers that do not actually have appropriate electric and thermal loads in spite of being within the target markets, do not use gas or have access to gas, do not have the space to install a system, do not have the capital or credit worthiness to consider CHP investment, or are otherwise unaware, indifferent, or hostile to the idea of adding CHP. The specific value for each size bin was established based on an evaluation of EIA facility survey data and gas use statistics from the iMarket database.

The rate of market penetration is based on a *Bass diffusion curve* with allowance for growth in the maximum market. This function determines cumulative market penetration for each 5-year period. Smaller size systems are assumed to take a longer time to reach maximum market penetration than larger systems. Cumulative market penetration using a Bass diffusion curve takes a typical S-shaped curve. In the generalized form used in this analysis, growth in the number of ultimate adopters is allowed. The curves shape is determined by an initial market penetration estimate, growth rate of the technical market potential, and two factors described as *internal market influence* and *external market influence*.

The cumulative market penetration factors reflect the economic potential multiplied by the non-economic screening factor (maximum market potential) and by the Bass model cumulative market penetration estimate.

Exhibit 2-12
Rhode Island Market Penetration for CHP Resources by Size, 2013

Case	50-500 kW	500kW-1,000kW	1-5 MW	5-20 MW	>20 MW	All Sizes
	(MW)					
Base Incentive Case	0	1	5	4	12	23
High Incentive Case	1	3	9	7	12	31

For purposes of the analysis considered herein, the penetration projections for the High Incentive Case are used.

CHAPTER THREE: DEMAND SIDE ALTERNATIVES

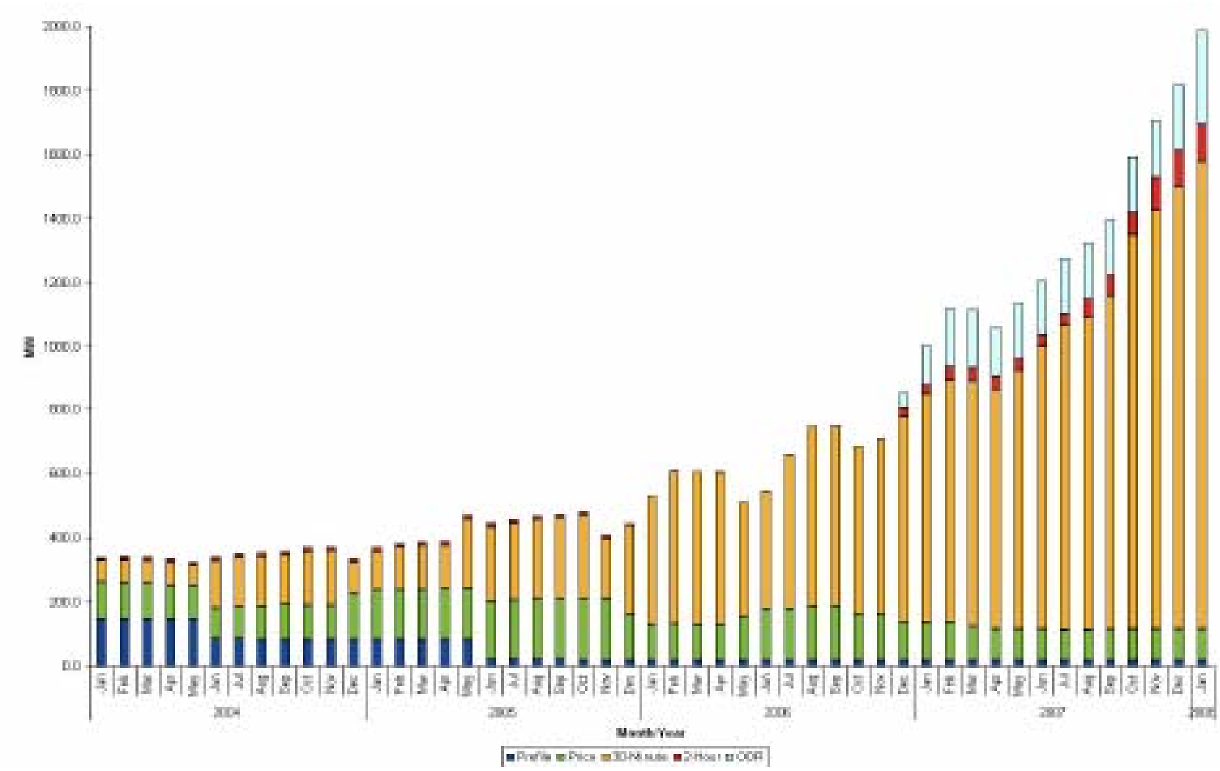
Demand side resources represent a large block of resource options that tend to reduce the demand for system generation and transmission services either through direct reductions in the load, or the addition of generation as a distributed source, i.e. distributed or emergency generation. Demand reductions may either be passive, such as energy efficiency programs that are tied to use of highly efficient equipment, or they may be active. Active resources reflect loads such as interruptible load contracts or distributed/emergency generators that can be responsive to system conditions or prices. Active resources are considered dispatchable by ISO-NE, though the performance of active resources programs, particularly non-generation specific programs, has not been tested under conditions in which they would be frequently called on, such as the large penetration levels considered in this analysis.

For this analysis, ICF projected DSM savings based on publicly available projections for the maximum technically achievable DSM and the market information revealed through the ISO-NE Forward Capacity Auction (FCA) process.

3.1 Background on Demand Resources in New England

Demand side resources have expanded considerably in the last several years. Exhibit 3-1 provides an overview of the growth in demand resources enrolled with ISO-NE between January 2004 and January 2008. As can be seen, there has been significant growth in 30-minute responsive reserves and Other Demand Resources (ODRs). ODRs reflect energy efficiency, emergency generation, and load management resources that can participate in the recently initiated forward capacity market in New England.

Exhibit 3-1
Demand Resources Enrolled with ISO-NE January 2004 – January 2008



This growth reflects an unprecedented amount of demand resources participating in the market. To participate as real-time resources, the demand resources must offer reductions as individual or grouped resources with a minimum reduction of 100 kW. They must be able to respond to real time capacity deficiency instructions from the system operator within either 30-minutes or 2-hours of the system operator's request, depending on the resource classification. Further, the resources need to offer a guaranteed 2 hour minimum reduction time. Resources will be compensated through both an energy and capacity mechanism. The energy mechanism reflects the greater of the real-time wholesale price of a guaranteed minimum of $0.50/kWh for 30-minute response and $0.35/MWh for 2-hour response. The capacity payment reflects a monthly payment ($/kW) based on the Forward Capacity Market Settlement Agreement.

To date, demand resources have performed well and have enhanced system reliability. However, the number of hours that the resources have been called on has been very limited. With the increasing volume of Demand Resources participating in the wholesale electricity markets, new planning and operational challenges are emerging. The 2010/2011 Forward Capacity Auction resulted in over 2,500 MW of demand resource capacity cleared, which reflected roughly 70 percent of the total resources which bid in that same auction. Resources submitting in the 2011/2012 forward capacity market reflect 4,218 MW or roughly 14% of the anticipated peak load. This continued growth is alarming from an overall resource adequacy and reliability planning standpoint, given that as demand resources grow in proportion to total resources, they will be relied upon to maintain system reliability. As demand response resources

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replace generation, there will be fewer generators available to satisfy the load and reserve requirements. Further, load reductions from demand response resources will be called upon more frequently to maintain the reserve requirements for a given expected load level. That is, as demand resources grow and displace generation resources, demand reductions will be called to perform in more hours.

Given that there is no history of performance, and the expectation for the initial auctions would not have accounted for the expansion in number of hours a demand resource is called to perform, there is a large question regarding the ability of the resources to perform for extended periods at more frequent rates.

Analysis performed by ISO-NE showed that if a total of 4,218 MW of demand resources cleared for the 2011/2012 period, demand resources would be required to be active in more than 200 hours under the 50/50 load growth projection for that resource year. In a case with roughly the 2,500 MW available from the 2010/2011 auction, the number of hours the resources would be called on was roughly 50. This reflects not only a quadrupling of the hours of need, but also implicit in this is the fact that the resources would be needed for longer durations under peak conditions. That is, the resources would be called on in consecutive peak days for a longer period of days (for example 7 consecutive days instead of 2 days) which places an extra performance burden on the load reduction resources.

Additional performance concerns exist for the demand resources, even beyond the extreme cases of need. Under conditions with heavy penetration of demand resources they would not only be called on in peak months, but would also be called on in shoulder periods to compensate for planned outages of generation units. This places an extra performance burden on the demand resources to reduce load in periods where the ability to do so might be limited. That is, the consumption levels may already be low when not driven up by weather conditions. Therefore, the ability to get the resource to respond on a timely basis could be limited.

These issues with demand resources reflect uncertainties which will need to be carefully considered and addressed going forward. Further, this calls into doubt the ability of demand resources, at such high penetration levels, to act as critical resources which would be able to provide surety of performance. Hence, the reliability benefit of demand resources at such penetration levels needs to be discounted for planning purposes.

3.2 Demand Side Resource Projections and Power-flow Assumptions

Demand resources as used here-in reflect measures that result in verifiable reductions in end-use consumption of electricity. These resources include both passive and active resources. Passive demand resources (Passive DR) save energy (MWh) during peak hours, are not dispatchable and may include on-peak and seasonal peak FCM resources. Active demand resources (Active DR) are designed to reduce peak loads (MW). These active resources can reduce load based on real-time system conditions or ISO instructions. They include critical peak, Real-Time Demand Response (RTDR), and Real-Time Emergency Generation (RTEG) in the FCM.

The FCM auction has been very successful at attracting demand resources in New England. Roughly 2,500 MW of demand resources cleared in first FCA (2010/2011). Of these, 700 MW or 31% represent Passive DR and 1,579 MW or 69% represent Active DR.

The second auction has yet to occur, but resources have submitted to qualify to participate. The total of demand resources in first FCA and those showing interest in the second FCA is over 4,200 MW. This represents approximately 14% of the peak requirement in the 2011/12 commitment period. Active resources reflect approximately 9% of the peak requirement.[31]

ICF has relied on the results of the first FCA and show of interest in the second as a basis for determining the DSM projections for 2013 used in the power-flow analysis. Further, where publicly available, ICF utilized current projections for resource potential for specific areas. Most publicly available projections were somewhat dated and inconsistent with the FCA results; however, the Connecticut 2008 Integrated Resource Plan did have analysis which was relied on as a basis for the Connecticut projections. The aggressive case growth assumptions in the Connecticut IRP reflected the highest growth rates of other technical studies for DSM potential in the New England area that were found in the public domain.

The Connecticut IRP presented two cases, a Reference Case, and a DSM Focus Case. The DSM Focus case reflects the more aggressive of the two and was relied on for this analysis as a conservative assumption for the power-flow analysis. That is, the aggressive DSM penetration has a more significant effect on reducing the need for transmission capacity and hence reflects a conservative assumption from the perspective of transmission planning. Exhibit 3-2 presents the DSM focus case from the Connecticut IRP. The resources labeled EE reflect non-dispatchable or passive energy efficiency resources while those labeled DR reflect active resources as per the descriptions above.

Exhibit 3-2
DSM Focus Case Connecticut January 2008 IRP (MW)

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
UI EE	10	13	24	38	57	81	107	131	157	182	208	234
UI DR	20	42	92	103	108	113	118	118	119	120	121	122
CLP EE	36	50	96	154	224	308	401	501	594	668	723	768
CLP DR	346	380	447	453	476	496	506	506	506	506	506	506
Total	410	484	658	748	865	998	1131	1257	1376	1476	1558	1630

Page D-15, Table D-4 CT IRP January 1, 2008, The Brattle Group.

Under the aggressive case (DSM Focus Case), DSM resources grow in total by 134% between 2008 and 2013, reflecting a 19% annual average growth in each of the next

[31] 14% reflects the share of the 2008 CELT/RSP ISO-NE forecast for peak. 9% is ISO-NE's estimate, which is believed to be based on the 2007 CELT/RSP forecast.

five years. This aggressive growth target was applied to the Rhode Island FCA auction results for the 2010/2011 period to determine the 2013 potential in the state. Active and passive resources were assumed to grow at the growth rates applicable to energy efficiency and demand response respectively. These results were cross-referenced with the implied resource base submitting interest in the 2011/2012 forward capacity auction such that the auction results are reflected for 2011/2012 and the IRP growth rate applied thereafter. The resulting DSM trajectories for total, passive and active demand resources are shown in Exhibit 3-3.

Exhibit 3-3
Rhode Island Projections for Demand Resources (MW)

Resource Type	2010	2011	2012	2013	2014	2015	2016
Total Resources	165	211	231	265	296	326	351
Passive Resources	46	65	83	113	144	174	199
Active Resources	120	146	148	152	152	152	152

2010 and 2011 results estimated based on share of resource type to total in 2010/2011 auction results and estimates of the 2011/2012 auction.
CT 2012 forward results based on DSM Focus case in 2008 IRP. All other areas assumed to remain flat in 2012 and grow at same rate as CT DSM Focus case as percent of peak thereafter.

These projections reflect the resources netted up for reserve margin and transmission losses (i.e., generation side) and hence these values reflect the distribution side load. The reserve margin gross-up used by ISO-NE for 2010/2011 was 14.3% and for 2011/2012 16.1%. ICF assumed the 2011/2012 gross up for later years.

Further discussion on the Connecticut IRP assumptions is provided in the next section.

3.3 Review of Demand Resource Plan in the January 2008 Connecticut Integrated Resource Plan

In January, 2008, the Brattle group published an Integrated Resource Plan (IRP) for Connecticut. Within this IRP, demand-side resource options were evaluated for their ability to meet future resource gaps.[32] Two levels of DSM efforts were considered. The “Reference Level” represents current and planned expenditures by the state and was identified within the study as already being “aggressive”. The “DSM-Focus Level” represents a significant expansion beyond this reference scenario and assumes that the programs would:

- promote the most efficient cost-effective equipment available,
- accelerate early retirement programs,
- achieve operational efficiencies by integrating program design and delivery, and,
- coordinate with other state-wide initiatives.

[32] Integrated Resource Plan for Connecticut, The Brattle Group, January 1, 2008.

This scenario was identified as a “very ambitious program that is unprecedented in New England” and would result in an actual reduction of demand below current levels by 2018. As an illustration of the aggressive nature of the estimate, it anticipates savings from emerging technologies not yet available to the mass market, such as LED general task lighting and heat-pump water heaters.

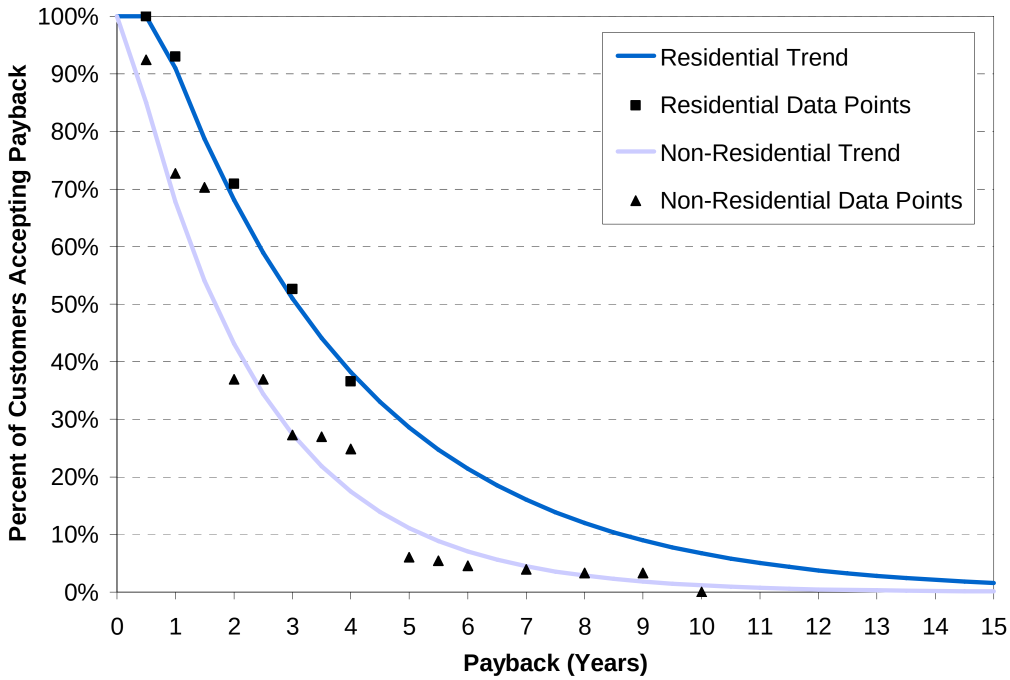
While the methodology used to develop this aggressive level is not highly detailed, the report indicates that one of the principal sources of the estimate was a study completed by GDS Associates[33]. This study was completed with the express purpose of estimating the long-term maximum achievable cost-effective potential within Connecticut and formed the foundation for the IRP’s estimate. It arrives at this estimate by first estimating technical potential (i.e., all measures for which it is technically feasible to install them), then maximum achievable potential (i.e., 80% of technically feasible potential), and finally maximum achievable cost-effective potential (i.e., achievable potential that meets the TRC test).

The assumption that 80% of technically feasible potential is achievable is very aggressive and reflective of the study’s philosophy that this value represents what “would be adopted given unlimited funding, and by determining the maximum market penetration that can be achieved with a concerted, sustained campaign involving highly aggressive programs and market intervention”. ICF’s typical estimate of achievable potential varies by measure and study, but generally ranges from 5% to 45%. Among the factors considered in our approach for determining achievable potential is the customers’ stated willingness to pay for a measure based solely upon its payback period.

Exhibit 3-4 shows the payback acceptance curves used by ICF and the data points used to derive them. The curve shows the percentage of consumers willing to pursue an energy-saving project at a given payback period. The complete curve was developed by a regression through the collected data points. The implication of the curve is that willingness to pursue a project drops off very quickly as the payback period rises. Though the vast majority of consumers would be willing to pursue a project with a payback of 1 year, only half are willing to accept a project with a 3-year payback.

[33] *Independent Assessment of Conservation and Energy Efficiency Potential for Connecticut and the Southwestern Connecticut Region*, **Final Report for the Connecticut ECMB, GDS Associates, Inc. and Quantum Consulting, June 2004**

Exhibit 3-4
Payback Acceptance Curves



Based upon this curve alone, substantial program incentives would be required to pay down payback periods to 0.5 to 1.5 years to achieve 80% of technical potential, and one would have to assume that participation is driven solely by payback period. More typical payback targets are 2 years. Also, as evidenced by the fact that much of the market has not transitioned to highly cost-effective fluorescent lighting, not all decisions are based upon payback alone. For these reasons, assuming that achievable potential is 80% is very aggressive.

In all, the IRP recognizes that the "DSM-Focus Level" scenario is an extremely aggressive level. As the study notes, the DSM ramp up rate is unprecedented, estimating a tripling of DSM activity in five years. Due to the GDS report's definition of achievable potential, its assumption of unlimited funding and highly aggressive marketing for cost-effective measures, the IRP's reliance upon emerging technologies to achieve savings, and the expectation that the scenario will result in eliminating more than 100% of load growth (an achievement that ICF is not aware of having occurred with any other utility), ICF considers this a highly-aggressive estimate of DSM potential.

CHAPTER FOUR: GENERATION RESOURCE ALTERNATIVES

Supply-side resources were also reviewed to ensure that adequate supply was maintained for generation planning purposes. The options considered included traditional generation supply such as combined cycles, combustion turbines, fossil steam units, nuclear units, and renewable units. The decision on the type of resource necessary to add to maintain adequate reserves was based on a high level assessment of the economics of these options. New generation capacity is primarily required to meet demand and reserve margin requirements and to satisfy the state level Renewable Portfolio Standards (RPS).[34] Some existing New England generation capacity is also expected to retire by 2013 due to changing market conditions and age of the units. Such retirements may be due to cost of operating aging units exceeding energy and capacity revenues, new technologies displacing aging fleets, or other factors. Details of the analysis are provided below.

4.1 Generation Capacity Additions

Generation additions for 2013 were based on public announcements for committed capacity and an assessment of basic capacity requirements based on a needs review. In assessing the need for new generation to meet demand requirements, consideration was first given to the DSM and CHP penetration within the market. That is, the peak load was considered after deducting the DSM and CHP resources which would serve to reduce the load requirements. Once the decremented load was determined, a basic analysis was performed to ensure that there would be adequate supply resources available to satisfy a reserve margin requirement. This was particularly important because increasing penetration of demand resources will reduce the need for generation capacity. For most of the New England market, ICF determined that due to the expected demand reduction from DSM and CHP, economic generation addition would comprise in large part minimal amounts of renewable energy sources which contribute to the state level RPS needs. This result is consistent with the New England forward capacity market auctions which reflect a depressed price for generation given the addition of significant demand resources. That is, the ability of the market to attract new generation at the prices cleared in the first capacity auction is extremely low relative to the capital required to construct such assets.

The Rhode Island RSP zonal load is expected to be under 3 GW at peak, and is further reduced by DSM and CHP installations. The current supply is over 4.5 GW of capacity, implying that there is more than a 50% reserve available and no additional local supply is needed to satisfy the reserve requirement.

In addition to looking at the reserve requirements, ICF reviewed requirements in the New England states for renewable generation resources (Renewable Portfolio Standards). Several of the New England states require that the load serving entities

[34] Renewable Portfolio Standards require that load serving entities supply a certain share of their load through renewable resources. If the load serving entities are not in compliance with these standards, a financial penalty is applicable.

serve a portion of their load through renewable resources and this percentage increases over time. Given that most states allow for the renewable resources to be located in neighboring areas, ICF evaluated the renewable need for New England as a whole. Further, we considered alternate compliance standards in the individual states which allow the load serving entities to pay a financial penalty rather than sourcing all or part of their requirement through renewable sources. To the extent that using renewable supply was more economic than the financial penalties for non-compliance, ICF determined the amount of renewable capacity which would be required in New England to satisfy the overall need.

This analysis was performed using ICF's Integrated Planning Model ™ (IPM®). IPM® is a widely used tool which simulates the operations of the power grid to optimally solve for dispatch, generation additions and retirements, compliance decisions, and power prices over time. Decisions on the timing and zonal location of new renewable resources are optimally made within IPM® based on the economics of the options available. Available options reflect options that are supported through the geographical and ambient conditions within the individual zones. ICF utilized its own capital and operating cost assumptions to consider the tradeoff between alternative compliance (or financial penalties) and new renewable capacity decisions.

The resulting need indicated approximately 196 MW of new renewable capacity would be needed in the Rhode Island zone by 2013 to help satisfy RPS requirements.

In order to locate these additions appropriately for power-flow purposes, ICF reviewed the current announced capacity additions in the New England queue and selected sites which most closely reflected the additions. The ISO queue for the Rhode Island zone is shown in Exhibit 4-1 below. Note that the Rhode Island RSP zone includes parts of southeastern Massachusetts and northwestern Connecticut. The 196 MW of renewable generation was sited at the West Kingston Substation in Washington County since this queue request had an expected in service date prior to 2013.

Exhibit 4-1
ISO-NE Generation Queue for Rhode Island Zone

Request Date	Project Type	Fuel Type[1]	Summer Net MW	County	State	Projected Commercial Operation Date	Proposed Point of Interconnection
2/26/2007	Combined Cycle	NG	320	Providence	RI	6/1/2012	345 kV RISE Substation
2/27/2007	Combined Cycle	NG	411	Windham	CT	5/31/2012	CL&P 345 kV Lake Road substation
4/13/2007	Gas Turbine	NG	100	Norfolk	MA	6/1/2011	345 kV NEA Bellingham substation
5/15/2007	Gas Turbine	NG	158.5	Worcester	MA	6/1/2010	ANP Blackstone 345 kV substation
5/15/2007	Gas Turbine	NG	158.5	Worcester	MA	6/1/2010	ANP Milford 115 kV substation
10/25/2007	Steam Turbine Capacity Uprate	BIT	190	Bristol	MA	6/302012	Brayton Point 345 kV Switchyard
11/2/2007	Combined Cycle	LFG	82	Providence	RI	9/1/2010	NGRID 115 kV S171 line
12/5/2007	Combined Cycle	NG	285	Newport	RI	6/1/2012	115 kV Tiverton Substation
5/7/2008	Combined Cycle	NG	551	Providence	RI	6/1/2009	115 kV RISE Substation
5/7/2008	Combined Cycle	NG,DFO	303.3	Norfolk	MA	6/1/2010	345 kV NEA Bellingham Substation
5/8/2008	Wind	WND	450	N/A	RI	12/31/2013	Brayton Point 345 kV bus or Dexter 115 kV bus
5/8/2008	Wind	WND	450	N/A	RI	12/31/2013	Kent County 345 kV bus or Davisville 115 kV bus
5/27/2008	Wind	WND	347	Washington	RI	12/1/2012	West Kingston Substation

1, NG = Natural Gas; BIT = Bituminous coal; LFG = Landfill gas; DFO = Distillate fuel oil; and WND = Wing.

4.2 Generation Capacity Retirements

Generation capacity retirement decisions were based on two main criteria:

1. the ability of generation units to meet their fixed and variable operating costs given expected market conditions, and
2. the age of the unit.

The former criteria (cost recovery) was specifically applied to generation facilities currently under Reliability Must-Run (RMR) contracts with ISO-NE since a reasonable estimate of their operating cost can be derived from publicly available market data as described below. Further these units have a documented history of inability to support their costs directly through the historic energy and capacity market prices which they have received through market sources alone. Given that the RMR contracts that these units operate under expire at the end of the forward capacity market transition period (2010) then these units would be forced to earn full compensation through the market assuming no other regulatory source was available. As the initial forward market capacity clearing prices have indicated prices well below the Cost of New Entry (CONE), any RMR unit which is known to have a regulated payment above the CONE was considered to retire by 2013. No units in Rhode Island were affected by this assumption; only units in Connecticut and Massachusetts are affected.

The latter criteria (age) was applied to all non-hydro units that will reach 60 years of operation before or in 2013. We assume these units are retired for purposes of the 2013 power-flow case. This assumption is consistent with that in ISO-NE's system planning process. Under this assumption, a total of 207 MW in New England will reach age of 60 by 2013 and retire. No units in Rhode Island are affected by this assumption.

The approach using these two criteria results in a conservative estimate of capacity retirements for several reasons. Rather than considering the operating costs for all units, we limit the review to only those units that are currently on RMR contracts. These units represent only a small amount of the total capacity which may be at risk of not being able to recover operating costs through realized market pricing. In particular, those units which are exposed to increasing cost requirements related to compliance with stricter air emissions standards such as carbon reduction programs, are also at risk. Coal generation facilities in particular face these environmental risks, though other types of generators are affected as well. Estimates for the expected carbon allowance prices range from roughly $5/ton to over $100/ton by 2013; this range is based on the severity and timing of the policies as well as the ability of resources to reduce carbon emission through control equipment (or reduction in output). Within the Rhode Island RSP zone, the facility most at risk due to possible tightening of air emission control policies is the Brayton Point[35] facility which includes over 1,100 MW of coal generation.

[35] Brayton Point is located physically in Somerset Massachusetts but is in the Rhode Island RSP zone.

CHAPTER FIVE: KEY ASSUMPTIONS FOR THE POWER-FLOW MODELING

This chapter provides additional detail regarding the overall assumptions used in the power-flow model. The power-flow case was based on the 2012 power-flow planning case from ISO-NE. The basic assumptions were updated to include more recent information available since the creation of that power-flow and also to reflect the alternative assumptions described in the previous three chapters. Note, the case was also updated to reflect the 2013 year rather than the 2012 year.

The key assumptions for the power-flow modeling include:

- Peak Load Characterization
  - 2013 Peak Demand Projection
  - Transmission Loss Adjustment
  - DSM and CHP Adjustments
- Supply Side
  - Existing Generating Capacity
  - Forced Outage Rate and Spinning Reserves
  - Capacity Additions and Retirements
  - Additional Dispatch Related Assumptions
  - Stressed Generation Capacity Case

5.1 Peak Load Characterization

5.1.1 2013 Peak Demand Projection

The ISO-NE load growth forecast issued in April 2008 is the source for the demand data used in this analysis. ISO-NE provides a reference load forecast that is characterized as having a 50 percent chance of being exceeded. An extreme weather peak demand forecast is also provided by ISO-NE that is characterized as having a 10 percent chance of being exceeded. In compliance with standard transmission reliability planning, ICF uses the extreme weather peak demand forecast (also known as the 90/10 forecast). Under the 90/10 forecast, the Rhode Island sub-area peak demand is estimated to be 2,965 MW in 2013.

ICF believes that relying on the ISO-NE projection for the 2013 year is a conservative assumption based on ISO-NE's own statements that indicate that their load projections for 1, 3, and 5 years into the future have been below the actual realized load growth on a consistent basis. The average forecast error ISO-NE has documented for the fifth year (the relevant year for our study) is biased to a 4.2% under estimate of peak. For the Rhode Island 90/10 case, this implies 125 MW of additional demand at peak, or a peak load of 3,090 MW rather than 2,965 MW.

5.1.2 DSM and CHP Adjustments

For power-flow modeling purposes, DSM and CHP resources are decremented from the peak demand level used in the model. The dispatchable DSM resources such as the emergency generators and demand response are assumed to be reserved for emergency conditions and are not removed from the ISO-NE peak load projection in the power-flow cases.[36] Thus, the Rhode Island peak load is only decremented by 113 MW to account for the non-dispatchable DSM resources for the power-flow analysis, accounting for about 43% of the total Rhode Island DSM projection. CHP resources are removed in total, reflecting an additional 31 MW decrement in peak demand. After accounting for the CHP and DSM resources, the power-flow peak modeling characterization is 2,821 MW for the Rhode Island zonal peak.

5.1.3 Transmission Loss Adjustments

The ISO-NE load projections are based at the generator bus-bar and hence include both transmission and distribution losses. In contrast, power-flow load inputs reflect the load at the distribution transfer point rather than at the generator level. As such, we have adjusted the ISO-NE load projections to remove transmission losses to reflect the distribution load levels. This allows for the power-flow to internally determine the transmission sector losses.

5.2 Supply Side Characterization

To establish a starting point for the Reference Case scenarios considered in the analysis, ICF first established a view of system dispatch under normal peak day conditions such that system operations were not stressed. This starting point dispatch utilizes the existing generation resources as reported by ISO-NE, and includes the ISO-NE typical generation unit forced outage rate and spinning reserve requirement.

5.2.1 Generation Capacity

ICF relied on the generation capacity for existing units as provided directly in the power-flow case. The capacity included in the power-flow case reflects the maximum summer-rated capacity for each unit. Additional modifications were made to account for capacity additions and retirements by 2013.

5.2.2 Forced Outage Rate and Spinning Reserve

The required forced outage rate in each zone is 7 percent of total capacity within the zone. To implement the forced outage in the power-flow model, ICF turned off selected generation units within each zone, to reach 7 percent of the total capacity. These units were considered not available to meet system demand.

[36] ISO-NE views dispatchable DSM as supply side resources

A spinning reserve requirement of 15 percent of total capacity was also implemented in the power-flow model. This represents generation capacity that is made available to respond to system contingencies. The 15 percent spinning reserve was implemented in each load zone with the exception of Rhode Island. Since Rhode Island is a net exporting region, it is expected that all generation units within that area will be operating at their available capacities on a peak summer day.

5.2.3 Capacity Additions and Retirements

Capacity additions and retirements as described in Chapter Four were incorporated into the power-flow cases.

5.2.4 Additional Dispatch Related Assumptions

Other unit specific dispatch requirements were modeled. For example, nuclear generation facilities are expected to operate at their full output on a typical summer peak day. Therefore in the model, all nuclear units throughout New England were fully dispatched. These assumptions did not affect generation dispatch in the Rhode Island area.

5.2.5 Stressed Case Generation Characterization

The study also assessed the ability of the system to operate reliably following the loss of selected generation resources in the study area. In each generation outage scenario the system was allowed to adjust following the loss of the generator.

The consideration of generation outage scenarios in this report is limited to the outage of the FPLE RISE generation facility in Rhode Island. This is because this facility is critical to electric transmission reliability in Rhode Island. Under the current system configuration, severe transmission line overloads may occur when the RISE facility is out of service. This type of stress case is necessary to consider for reliability planning purposes and is consistent with the NERC guidelines for such.

CHAPTER SIX: DETAILED RESULTS FOR THE RHODE ISLAND RELIABILITY PROJECT

This section presents the results of the power-flow analysis to determine if non-transmission resources, such as DSM, CHP and new generation capacity, can displace or delay the need for the Rhode Island Reliability Project. The power-flow analysis was conducted on the Pre-RIRP Case and the Rhode Island Case, and the results were compared to determine if the Project would provide reliability benefits above and beyond that of the non-transmission resources. In particular, ICF determined whether reliability violations existed in one or more sections of the transmission grid following the implementation of the non-transmission resources in the Pre-RIRP Case. ICF then evaluated system performance in the Rhode Island Case to determine the ability of the Project to resolve all the violations.

For both the Pre-RIRP Case and the Rhode Island Case, two main system conditions were examined – a Reference Scenario in which all generation facilities were allowed to operate as would be expected during a peak summer period, and a stressed generation case, the RISE Facility Outage Scenario, in which the RISE generation facility was assumed to be out of service. The power flowing on each transmission line, also referred to as the line loading, was measured and compared to the thermal limit or capacity of the line to determine if the power grid would operate reliably and continue to serve all consumers under the conditions that were simulated. For reliable system operation, the loading on each transmission line should remain within the emergency rating of the line. Similarly, substation voltages were measured and compared to the limits required for reliable system operation.

As described in detail below, ICF observed that the implementation of the non-transmission alternatives fail to resolve all the transmission line overloads that may occur in the Rhode Island area under anticipated operating conditions. This is particularly evident under contingency conditions, that is, during periods that one or more transmission facilities are out of service. Further, when the RISE generation facility is out of service, extreme conditions occur in the Pre-RIRP Case. The implementation of the Project resolves the reliability problems since it reinforces the Rhode Island area transmission backbone and also provides redundant transmission capacity across which power can be redistributed in case of a failure of other transmission elements.

In all cases, the contingencies shown in the following tables are those that result in the most severe overload for each monitored elements. The tables do not list all contingencies that impact the monitored element. The model simulation showed that in the Pre-RIRP cases, several different contingencies could cause overloads on the transmission elements shown.

6.1 Reference Scenario Results

Exhibits 6-1 and 6-2 summarize the performance of the Rhode Island area transmission grid in the Reference Scenario for both the Pre-RIRP Case and the Rhode Island Case. In Exhibit 6-1, all transmission elements are assumed to be operating as expected during a peak summer period, while Exhibit 6-2 shows system conditions if one transmission element is out of service. In both cases system performance is assessed after an additional transmission element is allowed to fail to reflect a system contingency, or an emergency condition that occurs during the peak period. This element is labeled Contingency in the two tables. Exhibit 6-1 therefore displays results assuming a single transmission element is unavailable, while Exhibit 6-2 shows results if two transmission elements are unavailable.

The tables list transmission facilities that will be overloaded or heavily loaded under the simulated conditions. A description of the facility is given in the column labeled Monitored Element. In addition, the expected line loading for the selected transmission facility is given as a percentage of the limit of the line.

For example, as shown in Exhibit 6-1, if Line 332[37] goes out of service, the loading on the 115 kV line from Drumrock to West Cranston 72 is expected to increase to its capacity or thermal limit (98% loading) if the Project is not implemented (Pre-RIRP Case). However, if the Project is in service (Rhode Island Case), the loading on the line following the same contingency outage is expected to fall below 50% of its emergency rating. Similar information is shown in the rest of the table.

Exhibit 6-1
N-1 Rhode Island Line Overloads, Reference Case

Line Out of Service	Contingency	Monitored Element				Line Loadings - (%)	
Line Name-ISO	Line Name-ISO	From Bus	From KV	To Bus	To KV	Pre-RIRP 2013	Rhode Island 2013
None	332	Drumrock	115	West Cranston 71	115	103%	52%
None	332	Drumrock	115	West Cranston 72	115	98%	< 50%
None	332	Drumrock	115	Kent Co. T1	115	84%	< 50%
None	332	RISE 171	115	West Cranston 71	115	85%	< 50%
None	332	West Cranston 72	115	RISE 172	115	84%	< 50%
None	332	Franklin Square	115	Hartford Ave.	115	84%	54%

Exhibit 6-1 shows that if the Project is not implemented, the failure of a single transmission element during a peak summer period when all other transmission facilities are operating as expected, will cause heavy loading on several 115 kV transmission lines. Line overloads will, however, be minimal. The severity of the overloads will likely increase as demand increases in subsequent years. The implementation of the Project

[37] Line 332 refers to the 345 kV line from West Farnum Substation to Kent County Substation.

reduces line loadings on all the lines considerably, providing reserve transmission capacity to meet further growth in demand. This is because the Project will provide transmission reinforcements in the Kent County area.

The line overloads are much more severe if at least one transmission element is out of service prior to the failure of another transmission element. As shown in Exhibit 6-2, following the failure of a second line, the Pre-RIRP loadings on several transmission facilities exceed the line capacities by 30% to 60%. Such severe overloads can lead to loss of additional transmission facilities, compromising the ability of the grid to reliably serve demand. The transmission reinforcements from the Project reduce loadings below the line limits and, in addition, provide reserve transmission capacity.

Exhibit 6-2
N-1-1 Rhode Island Line Overloads, Reference Case

Line Out-of-Service	Contingency	Monitored Elements				Line Loadings - (%)	
Line Name-ISO	Line Name - ISO	From Bus	From KV	To Bus	To KV	Pre-RIRP 2013	Rhode Island 2013
332	Drumrock 7289	West Cranston 72	115	RISE 172	115	158%	66%
332	Drumrock 7289	Drumrock	115	West Cranston 72	115	153%	61%
332	Drumrock 7289	RISE 171	115	West Cranston 71	115	156%	65%
332	Drumrock 7289	Drumrock	115	West Cranston 71	115	153%	62%
332	Drumrock 7289	Drumrock	115	Kent Co. T1	115	135%	< 50%
332	Hartford Ave. 725	Franklin Square	115	Hartford Ave.	115	130%	82%
332	Drumrock 7289	Drumrock	115	Kent Co. T7	115	87%	< 50%
332	Drumrock 7289	RISE 172	115	RISE	115	106%	71%
332	Hartford Ave. 7205	RISE 171	115	RISE	115	102%	69%
332	Hartford Ave. 7205	Johnston 171	115	Hartford Ave.	115	80%	< 50%
332	Hartford Ave. 7205	Johnston 172	115	Hartford Ave.	115	80%	< 50%

6.2 RISE Unit Outage Scenario Results

The 550 MW FPLE RISE generation facility is a critical generation unit in Rhode Island. An assessment of system conditions assuming the outage of the RISE generation facility shows severe thermal and voltage violations in Rhode Island in the Pre-RIRP case. For example, following an outage of the RISE generation facility and the loss of line 332, a contingency outage of line S-171S or line T-172S results in a voltage collapse[38] in the Rhode Island area. Operator action to prevent impact to a larger section of the grid may include load shedding.

Exhibits 6-4 and 6-5 summarize the expected system performance if the FPLE RISE generation facility is out of service during a peak summer period. As shown in Exhibit 6-4, if a single transmission element is out of service, several transmission lines will be

[38] Voltage collapse usually occurs when the grid is required to serve more load than the voltage can support. Under such conditions, system voltages decline progressively, and can result in a local or regional blackout.

loaded close to, or just above, their capacities. The 115 kV transmission line from Franklin Square to Hartford Avenue exceeds its emergency rating by 31% in the Pre-RIRP Case.

If a second transmission facility goes out of service, the transmission line overloads become excessive. The line loading for several transmission lines exceed their thermal ratings by more than 60% in the Pre-RIRP Case.

Similar to the Reference Case, the implementation of the Project results in significantly reduced line loadings on all the transmission facilities and resolves the identified transmission reliability issues.

Exhibit 6-3
Location of FPLE RISE Unit

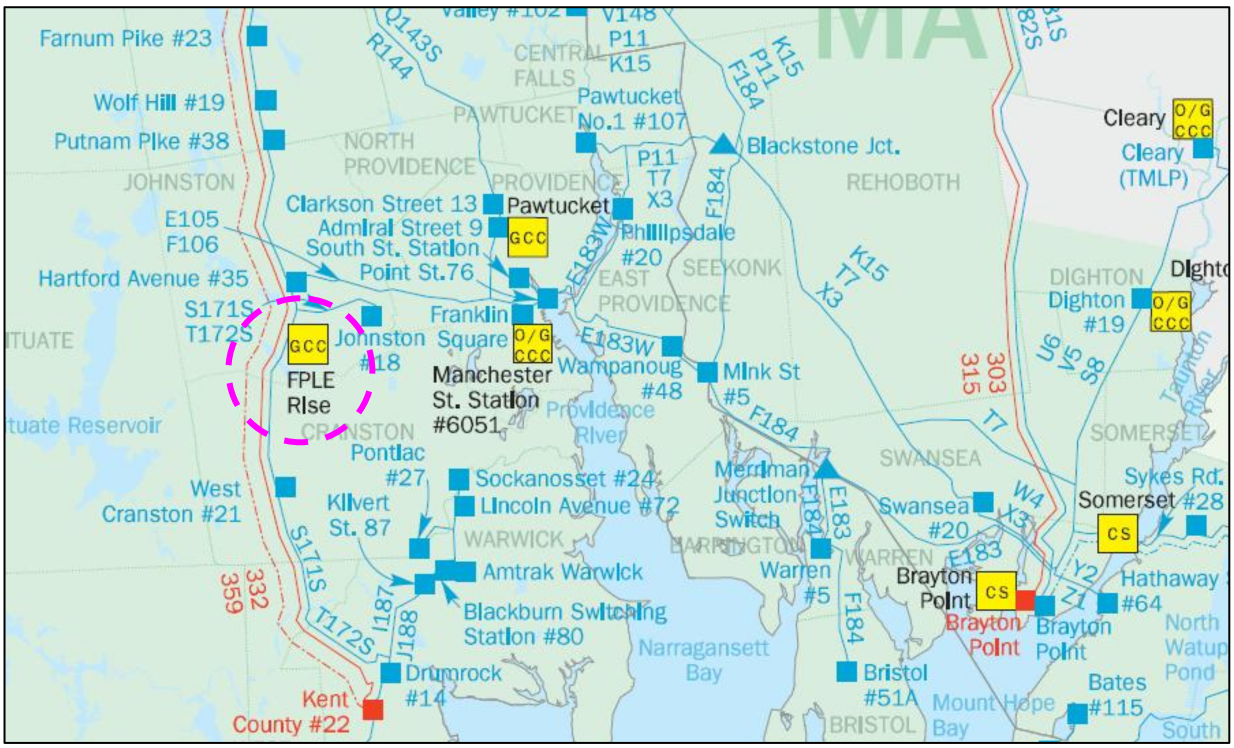


Exhibit 6-4
N-1 Rhode Island Line Overloads, RISE Unit Outage Case

Line Out-of-Service	Contingency	Monitored Elements				Line Loadings - (%)	
Line Name-ISO	Line Name-ISO	From Bus	From KV	To Bus	To KV	Pre-RIRP 2013	Rhode Island 2013
None	332	Johnston 171	115	Hartford Ave.	115	106%	< 50%
None	332	Johnston 172	115	Hartford Ave.	115	105%	< 50%
None	332	Drumrock	115	West Cranston 71	115	97%	< 50%
None	332	Franklin Square	115	Hartford Ave.	115	131%	83%
None	332	Phillipsdale	115	Franklin Square	115	97%	< 50%
None	332	Brayton Point	115	Warren 83	115	98%	52%
None	332	Drumrock	115	West Cranston 72	115	92%	< 50%
None	332	West Farnum	115	West Farnum Tap 1	115	92%	< 50%
None	332	Johnston 171	115	RISE 171	115	82%	< 50%
None	332	West Farnum	345	West Farnum	115	83%	< 50%
None	332	Mink Street 183	115	Wampanoag	115	83%	< 50%
None	332	West Farnum	115	West Farnum Tap 2	115	82%	< 50%
None	332	RISE 171	115	West Cranston 71	115	81%	< 50%
None	332	Mystic CT	115	Whipple Junction	115	76%	< 50%
None	332	West Cranston 72	115	RISE 172	115	80%	< 50%
None	332	Johnston 172	115	RISE 172	115	78%	< 50%

Exhibit 6-5
N-1-1 Rhode Island Line Overloads, RISE Unit Outage Case

Line Out-of-Service	Contingency	Monitored Elements				Line Loadings - (%)	
Line Name-ISO	Line Name - ISO	From Bus	From KV	To Bus	To KV	Pre-RIRP 2013	Rhode Island 2013
332	Hartford Ave. 7205	Johnston 171	115	Hartford Ave.	115	195%	65%
332	Hartford Ave. 7205	Johnston 172	115	Hartford Ave.	115	195%	65%
332	Hartford Ave. 7205	Johnston 171	115	RISE 171	115	172%	51%
332	Hartford Ave. 7205	Johnston 172	115	RISE 172	115	168%	< 50%
332	Drumrock 7289	Drumrock	115	Kent Co. T1	115	120%	76%
332	Hartford Ave. 7205	West Farnum	115	West Farnum Tap 1	115	93%	< 50%
332	Hartford Ave. 7205	Phillipsdale	115	Franklin Square	115	92%	< 50%
332	Hartford Ave. 7205	Brayton Point	115	Warren 83	115	87%	< 50%
332	Hartford Ave. 7205	Mink Street 183	115	Wampanoag	115	85%	< 50%
332	Hartford Ave. 7205	RISE 171	115	West Cranston 71	115	82%	< 50%
332	Hartford Ave. 7205	West Cranston 72	115	RISE 172	115	81%	< 50%
332	Hartford Ave. 7205	Drumrock	115	West Cranston 71	115	80%	< 50%
332	Drumrock 7289	Drumrock	115	Kent Co. T7	115	77%	< 50%
332	Hartford Ave. 7205	West Farnum	115	West Farnum Tap 2	115	79%	< 50%

6.3 Demand-side Reduction Scenarios

The assumptions in the Reference Scenario regarding the penetration of additional demand and supply side resources over time are derived considering an aggressive demand side penetration in combination with a primarily economic driven generation addition.[39] ICF considered an alternate approach to this to determine the total incremental amount of demand side resources which would need to be added in order to provide similar reliability benefits to those achieved in the Reference Case already including both transmission and non-transmission alternatives. This is a step in assessing whether there is a feasible alternative to the transmission solution beyond the penetration level already assumed; hence it supplements the Reference and unit outage cases examined.

Under this scenario, the full quantity of CHP, DSM, and generation resources included in the Reference Case were assumed to be online as a starting point. From this case, the

[39] Generation additions are primarily driven based on ensuring that adequate reserves are maintained over time. The types of resources added are those which would provide the least cost option to maintain reserves. In addition, units which may already be under construction, or units which are had been approved in non-marketed programs (such as the Kleen unit in Connecticut) at the time this analysis began are considered as generation additions.

peak load was then decremented until all line overloads were resolved and similar line flows to the Reference Case with the Project online were achieved.

The findings, based on the power-flow analysis, indicated that the incremental load decrement which would need to be applied as a uniform percentage reduction to all load points in the Rhode Island zone would be between 1,500 MW and 2,000 MW. This reflects roughly 50 to 70 percent of the peak demand projected for the entire Rhode Island sub-area over and above the 5 percent of peak demand already decremented for as active DSM and CHP resources.

Given the importance of the location of load reductions on power-flow and line loadings, we further examined a scenario in which local load reductions were assumed at key load points rather than uniform load reductions. In cases where problems are isolated to specific geographical points, one would expect that a lesser total reduction would be necessary, i.e. one is attacking the problem at the source. Under this scenario, the Drumrock, Kent County and Johnston substations were identified as key contributers to the identified reliability issues, and the assumption was made that all load at these three substations was set to zero. This removed 294 MW of coincident peak load. With this change alone, overloads continued to exist on the system and as such, further uniform decrements were applied to all points in the Rhode Island zone until overloads were addressed. A total of 1,000 MW were required to be decremented through curtailment of other means in addition to the 294 MW site specific load for a total of 1,294 MW load reduction. This still reflects over 40 percent of the 90/10 projected peak load for the Rhode Island zone in 2013. Our conclusion from this analysis was the site specific loads which most contribute to the local line overloads is not significant enough to reduce line overload issues in the area, even in the extreme case where all local load was eliminated.

One final demand decrement scenario, relating to exports to Connecticut, was considered. This export case was analyzed to consider if loop flows and exports to Connecticut may be contributing to the overloads. In this case, a load reduction was applied in Connecticut as well as Rhode Island. Similar to the site specific decrement case, the power-flow results indicated that even with a 1,000 MW reduction in Connecticut, at least 1,000 MW of reduction would be required in Rhode Island as well.

The demand reduction that has been found to be necessary in the Rhode Island zone based on these several cases reflects an unrealistic level of resources. The resulting peak demand in the Rhode Island sub-area would need to be between 800 and 1,500 MW to achieve the reliability benefits of the Project. This reflects a situation where in 2013, the peak load would need to be reduced by 40 to 70 percent of today's peak demand level, a situation not able to be technically achieved.

CHAPTER SEVEN: CONCLUSIONS

It is evident from this study that the Rhode Island Reliability project is critical to the reliable operation of the New England transmission grid, and in particular, the Rhode Island transmission system. This conclusion is supported by results of the power-flow analyses, which indicate that the implementation of non-transmission alternatives alone will not be sufficient to resolve the numerous transmission facility overloads and substation voltage violations that could potentially occur when some key transmission elements are out of service.

The study has shown that the Project will sufficiently resolve the overloads and violations. In addition, the transmission reinforcements from the Project will provide reserve transmission capacity that can be used to redistribute power in the event of a system emergency, and which will also be available to meet future system needs as demand grows in the Rhode Island area.

ICF's study examined a Reference Scenario that reflected summer peak conditions in 2013, assuming all facilities operated as expected. Non-transmission alternatives, including DSM, CHP and new generation capacity, were implemented in this scenario. To a large extent, the grid would be able to serve consumer demand under these conditions if all transmission facilities remained in service. If one of a number of key facilities is out of service, however, the ensuing severe overloads would compromise the integrity of the grid in the Rhode Island area. The Project will provide additional transmission capacity that will resolve these reliability problems. Further, the study has shown that the magnitude of demand-side options necessary to achieve similar reliability benefits to the Project are not feasible.

The study also showed that system conditions worsen considerably if the FPLE RISE Generation facility is out of service, especially if this is coupled with the outage of one of several transmission lines.

Since Rhode Island has limited high voltage (345-kV level) connections to the rest of the New England 345-kV transmission backbone, and limited generation connected to the 115-kV system, the additional 345-kV capacity provided by the Project significantly improves the reliability of the Rhode Island transmission grid.

The conservative nature of the assumptions used in the study further reinforces these conclusions. Even under these conservative assumptions, the reliability of the system must be addressed through the proposed transmission upgrade. Less conservative assumptions would result in greater line overloads and voltage violations than determined in this study.

APPENDIX 1: GLOSSARY OF TERMS

Active demand resources –Dispatchable demand-side resources.

Combined Heat and Power – Systems used typically at industrial or commercial sites to generate electricity and steam/heat for onsite operations and use, thus reducing the load on the generation and transmission system.

Contingency – A situation in which one or more elements of the power system have failed. These elements might include a generating station, transmission line, or a transformer.

Critical peak resources – Active demand-side resources which reduce their load during forecasted peak hours (realized in the day-ahead time frame) and shortage hours (realized in real-time).

Demand resources – A variety of techniques used to reduce electrical demand in order to reduce system-wide generation and transmission requirements. Demand resources are also referred to as **Demand-side Management**. Demand resources can be "active" or "passive."

Distributed generation – Generation resources directly connected to end-use customer load and typically located behind the end-use customer's billing meter. Distributed generation resources may be used for routine energy generation or for emergency use only, and typically have a capacity less than 5 MW.

Distribution-side load – A measure of the system load at the end-user point.

Emergency operating conditions – In this study, emergency operating conditions refer to a system state in which two components of the bulk power system have failed. Compare to **Normal operating conditions.**

Forced outage rate – The percentage of time that a given generating unit is unable to function due to unanticipated breakdown or emergency conditions.

Forward capacity auction (FCA) – The mechanism through which supply and demand resources are bid into and selected to participate in the Forward Capacity Market (FCM). The FCA is held two years prior to the commitment period for which the resources cleared in the market must provide the generating capacity or demand-side resources bid into the auction. In the New England market, commitments of up to five years are available for demand resources and units are paid the market-clearing electricity price during their demand-reduction actions.

Forward capacity market (FCM) – A market designed to procure capacity from willing providers of new generating resources and demand resources already available, but not used, in a system.

Generator bus-bar – Connects a given generator to the step-up transformer.

Load deficit – The amount of load unable to be served reliably.

Market penetration – The measurement of the relationship between the total potential use of a product or technology in a given market and its actual use.

N-1 – Power system state where one component of the bulk power system has failed.

N-1-1 – Power system state where two components of the bulk power system have failed.

Normal operating conditions – In this study, normal operating conditions refer to a system state in which no more than one component of the bulk power system has failed. Compare to **Emergency operating conditions.**

Passive demand resources – A set of demand resources whose use are outside the direct control of the grid operator and not *necessarily* correlated to the relationship between demand and supply of energy in a system. Examples of passive demand resources include energy-efficient equipment, such as refrigerators and air conditioners, and compact fluorescent lights.

Payback – The number of years it takes for the annual operating savings to repay the initial capital investment of a particular technology or upgrade.

Power-flow case – a modeling representation of the physical power system, including generation units, load, transmission facilities, transformers, reactive compensation devices, DC lines, and phase angle regulators.

Real-time demand response – Resources which must reduce their load within 30 minutes of receiving instructions from the ISO, and wait until further instructions come before they may restore usage.

Real-time emergency generation – Distributed Generation Resources which must reduce their load within 30 minutes of receiving instructions from the ISO, and wait until further instructions come before they may restore usage. Limited to 600 MW system-wide in the NE-ISO.

Reliability Must-Run (RMR) – RMR units are generation facilities that are no longer economical to operate on an on-going basis, but that are required for system reliability purposes. These generating facilities enter into RMR agreements with NE-ISO and that provide for payments to the plants so the plant owner will maintain the units in a ready operating state in case the plants are required to maintain the reliability of the power system.

Renewable Standards Portfolio (RSP) – Policies under which many governments at the state level have mandated different levels of renewable generation to electric utilities within certain timeframes.

Spinning reserves – Supply available to serve load in the event of a contingency that are available on short notice, typically around 15 - 30 minutes time.

Substation – A facility containing switches, transformers and other equipment used to switch, change, regulate, and monitor voltage in the electric transmission and distribution system.

Voltage violation – An incident in which the voltage at a substation reaches levels outside of safe operating limits.