STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS

PUBLIC UTILITIES COMMISSION

IN RE: INVENERGY THERMAL DEVELOPMENT LLC	)	
APPLICATION TO CONSTRUCT AND OPERATE THE	)	Dkt. 4609
CLEAR RIVER ENERGY CENTER, BURRILLVILLE,	)	
RHODE ISLAND	)	

RELEVANT SECTIONS OF INVENERGY THERMAL DEVELOPMENT LLC'S ENERGY FACILITY SITING BOARD APPLICATION FOR THE PUBLIC UTILITIES COMMISSION ADVISORY OPINION

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TAB 1

Invenergy

1 South Wacker Drive, Suite 1800
Chicago, IL 60606

October 28, 2015

Todd Anthony Bianco, Coordinator
Rhode Island Energy Facilities Siting Board
89 Jefferson Boulevard, Warwick, RI 02888

Re: Clear River Energy Center – Energy Facility Siting Board Application

Dear Commissioners:

Invenergy Thermal Development LLC (Invenergy) is requesting approval from the Rhode Island Energy Facility Siting Board (RIEFSB) to construct and operate the Clear River Energy Center ("CREC"), a combined-cycle electric generating facility to be located on Wallum Lake Road (State Route 100) in Burrillville, Rhode Island (the Project or the Facility). The Project will provide many benefits to the region including reduced air emissions, improved air quality, lower regional energy costs, employment for skilled local workers during construction and operation. In addition, there will be direct economic benefits to the Town of Burrillville and to local businesses.

The Facility will be configured as a two-unit one-on-one (1x1), combined-cycle generation station. Each unit will consist of an advanced class combustion turbine operated in a combined-cycle configuration with a heat recovery steam generator (HRSG), a steam turbine and an air cooled condenser (ACC) for each train. The combustion turbine, steam turbine, and generator of each unit will be connected via a common shaft (otherwise referred to as a single shaft machine). Each gas turbine will fire natural gas as a primary fuel and ultra-low sulfur diesel (ULSD) fuel as a backup fuel.

The CREC Facility will have a nominal power output at base load of approximately 850-1,000 megawatts (MW) while firing natural gas. The electrical power generated by the Facility will be transmitted through a new 345-kV transmission line to be installed from the Facility through an existing National Grid right-of-way (ROW) to the Sherman Road Substation in Burrillville, Rhode Island.

The CREC will utilize air cooling with an air cooled condenser which reduces water consumption by more than 90 percent as compared to a traditional water cooled plant. The water supply for the Facility will be provided by the Pascoag Utility District (PUD) through a dedicated pipeline to be installed from an existing PUD well to the Facility. Wastewater from the Facility will be discharged to the Burrillville Wastewater Treatment Facility through a dedicated sewer line that will connect to the local sewer system.

The Facility will be equipped with state-of-the art air emissions control and sound abatement systems and has been designed to minimize and avoid impacts to the environment to the greatest extent technologically and economically feasible.

FACILITY BENEFITS

The Facility being proposed will participate in the ISO New England Forward Capacity Market in order to address need for new capacity that has been created by announced and pending retirements of existing generators and load growth. Additional retirements are expected to occur due to changing market conditions, the age of a good portion the existing generation fleet and as a result of improved market performance as mandated by the EPA's Clean Power Plan. More specifically CREC will provide potential benefits including:

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1. Utilization of Existing Infrastructure: The Facility is located on a site within the Town of Burrillville that is part of a larger parcel of land that includes both gas pipelines and electric transmission lines each of which have adequate capacity to support the project without requiring additional costly (and controversial) laterals for each of these interconnections.

2. Compliance with State and Federal Energy Policy: The design of the proposed CREC Facility is in compliance with the policies and requirements of the EPA's recently announced Clean Power Plan as well as the recently issued R.I. State Energy Plan and the cooperative efforts of the regional states as they relate to types of technologies needed in order to improve air quality and reduce emissions.

3. Modernize and replace aging generation infrastructure: the Facility will be the most efficient power generator in the New England market to date and will replace older, more polluting, less efficient and less flexible modes of power generation that the region currently relies upon.

4. Environmental Benefits: The CREC Facility will provide additional environmental benefits in the form of:
    a. Clean up and possible complete remediation of a currently shut down and contaminated well in Burrillville. The use of Pascoag Utility District's (PUD) well, which was deemed unsuitable for drinking water purposes more than ten years ago due to contamination, will be accomplished by installing a ground water treatment system. Through the installation of the treatment system, CREC's use and cleaning of the groundwater has the potential to eventually lead to complete remediation of the groundwater, as an additional environmental benefit of the CREC Project.
    b. Invenergy analyzed the air emissions impact of the CREC on the ISO-NE and New York ISO ("NYISO") footprints (both ISO-NE and NYISO footprints were considered given their high degree of interconnectivity) and found that the addition of the CREC will reduce CO2, NOx and SO2 emissions every year when compared to existing system wide emission rates. Invenergy's analysis also determined that without the CREC Facility, the recently announced retirement of the Pilgrim nuclear facility would have resulted in higher regional emissions (through more dependence on existing generation sources), and as a result of the CREC Project emissions reductions are forecasted to be even greater in the region when this nuclear facility is retired.

5. Economic Benefits: CREC will create economic benefits from the large investment, the added new employment for skilled local workers during construction and operation, as well as direct economic benefits to the Town of Burrillville and to local businesses. Economic development benefits associated with CREC will result from the following three areas:
    a. Construction of the facility – Equipment, materials, and skilled labor employed during construction as well as, permitting fees, and expenditure associated with other project activities. The construction of CREC will support the creation of new construction jobs and generate millions of dollars per year in income for Rhode Island residents during the construction period.
    b. Ongoing operation of the Facility – Upon conclusion of the construction phase, ongoing facility operations create expenditures associated with the materials and labor needed to operate the facility which will support additional economic benefits in the form of new jobs, added property taxes and added monies for Rhode Island residents.

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c. Power market cost savings to Rhode Island ratepayers – The addition of new efficient generation capacity in Rhode Island will result in lower capacity and power prices in the near term, thereby driving significant savings to Rhode Island.

ADDRESSING MARKET NEEDS

The CREC proposal will help the New England Independent System Operator (ISO-NE) meet its capacity, reliability and operational requirements for the regional electric transmission network. The restructuring of New England's electric power industry in the late 1990s created an open, competitive wholesale electricity marketplace that is managed by the ISO-NE. The marketplace allows the ISO-NE to secure sufficient electricity and related services for the region at the lowest prices. The ISO operates a Forward Capacity Market to ensure the reliability of the New England power supply and assign Forward Capacity Obligations (FCO) to Generation Suppliers. Invenergy will offer the CREC Project into upcoming Forward Capacity Auction(s), and once the Project is awarded an FCO, Invenergy will construct the Facility. The CREC Project will be able to address many of the challenges facing the New England ISO region, more specifically:

- Provide new, highly advanced generating technology that will be one of the most efficient generators in New England, helping lower regional energy costs.
- Reduce regional air emissions by displacing older, less efficient and more polluting generation and improve air quality through the facilities use of best available emission control technology.
- Modernize the electric generating infrastructure by providing new, highly efficient generation that has fast start and high ramp rate (flexible) generating capability, replacing older, less flexible generation. The fast start and flexible generating capability will support the integration of new and existing renewable generation onto the power grid.

The region's coal- and oil-fired generators represent approximately 28 percent of the installed power generating capacity and most are more than 40 years old. These units are far less efficient than CREC and rely on more expensive fuels as compared to natural gas which means they have higher operating costs. Their higher operating costs result in these units running mainly to meet peak demand and only produced a small portion of the region's electricity, which is one of the reasons these units are retiring and being replaced by newer, more efficient generators.

The performance of the existing older resources can be uncertain when called on, due to age and infrequent operation, posing risks to reliability. For example:

- Equipment issues can affect their performance when dispatched. Unexpected outages of older units tend to increase during extreme cold conditions.
- They have long start-up times. In some instances up to 24 hours are needed to reach full output, which makes it difficult for ISO-NE operators to rely on these resources.

Regional power markets have shifted in recent years in response to fast-changing supply and demand parameters. The ISO-NE has identified issues that have led to inadequate peak generation capacity that have resulted in high-profile "narrowly missed catastrophic events" that have spurred market design changes like the new Pay-for-Performance Initiative (PI) that will result in a more efficient, flexible fleet, and penalize less reliable and more inflexible oil/gas steam-fired units that cannot respond to the market signals in a timely fashion. This market change will likely result in accelerating retirements of oil/gas steam capacity and incentivize the construction of newer and more efficient units.

The proposed CREC, along with the new market rules should result in lower energy prices in ISO-NE, as more efficient units displace less economic generation.

RATEPAYER SAVINGS

Rhode Island ranks 7th highest in average price of electricity to end-use customers in the nation (*Source: U.S. Energy Information Administration, Form EIA-826, Monthly Electric Sales and Revenue Report with State Distributions Report)*. Rhode Island residential consumers pay about 35 percent more for electricity than the national average. In addition, the price of electricity for industrial use is 64 percent higher in Rhode Island compared to the national average. This puts Rhode Island businesses and industries in a disadvantageous cost-position to compete across the nation and reduces disposable income for Rhode Island residents.

Due to its high efficiency, CREC will likely reduce the electricity price for end-use consumers by producing energy at a lower cost than other existing generators. Invenergy's studies indicate that from 2019 to 2022, cumulative savings to Rhode Island ratepayers resulting from the electricity price reductions that are anticipated by the CREC Project are projected to be over $280 million, or approximately $70 million annually. This represents significant savings to Rhode Island ratepayers.

The price of natural gas is a key component to cost of electricity produced by CREC. The natural gas supply system has been constrained in recent years which has led to increased gas price in the region. In fact, the cost of natural gas in the region can at times be the highest in the United States, whereas the lowest price of natural gas in the United States is right next door in Pennsylvania. This cost difference is entirely due to the capability of the natural gas pipeline infrastructure capability to meet demand. This is the reason that Invenergy took the unique approach to include an incremental pipeline expansion to meet CREC's fuel supply needs as part of the CREC development. The ratepayer savings described above were based on this approach.

COMPLIANCE WITH RHODE ISLAND AND FEDERAL ENERGY POLICIES AND PLANS

Both the recently issued Rhode Island State Plan -- *Energy 3035* (State Guide Plan Element – Report #120) and the EPA's Clean Power Plan (CPP), calls for reductions in emissions and an increase in regional renewable generation. There are several ways in which to do this, but given New England's already high cost for energy, the implementation of the goals set forth in the State Energy Plan and the CPP must be accomplished in a cost effective manner. Renewable resources such as solar and wind create challenges for grid operators due to their intermittent and variable nature which can have rapid and sizeable swings in electricity output due to wind speed, time of day, cloud cover, haze, and temperature changes (which is why they are called variable or intermittent resources). Intermittent resources are not dispatchable on demand and, as such, have a limited ability to serve peak load. The ISO-NE needs to balance the variable output from wind and solar resources, in order for the power system to operate reliably. In order to do this, the ISO-NE must hold generating units in reserve, or have access to units that have highly flexible operating characteristics that allows them to adjust output to meet changing conditions. This means that the generation fleet needs to evolve as more renewables are added. This includes the ability of generators to react to rapid and sizeable swings in electricity output as well as having additional fast-start capacity held in reserve. The CREC Project supports these security, cost effectiveness and sustainability goals recommended in the RI State Energy Plan by complementing and supporting the introduction of more renewable generation resources.

The proposed CREC Facility located in Burrillville has the necessary characteristics to meet the challenges of a renewable future and units like CREC cannot be considered as being independent or in

Invenergy

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lieu of renewables but rather necessary in order to support the further development and addition of renewables as a crucial part of the solution to the regional efforts to meet the Clean Power Plan goals as well as the Rhode Island State Energy Policy.

Invenergy respectfully requests an expedited review of this application and a Final Decision on its approval by no later than September 15, 2016. This Facility will be bid into the ISO-NE's Forward Capacity Auction number 10 ("FCA 10") in February 2016, and if selected, commercial operation of the Facility will be required by June 1, 2019, with significant financial penalties due if this capacity obligation is not met. In order to meet this obligation, construction of the facility needs to commence in late 2016. A RIEFSB Final Decision by no later than September 15, 2016 would allow sufficient time for project financing and construction commencement to meet the FCM 10 capacity obligation deadline. Invenergy will work with and provide the RIEFSB with the information necessary to make a timely Final Decision.

Thank you in advance for your assistance with meeting this important project timeline milestone which should allow the CREC to provide the above mentioned benefits to Rhode Island and the region,.

Best Regards,

John E. Niland
Director, Thermal Development

cc: Richard Beretta
Alan Shoer

TAB 2

1.0 PROJECT OVERVIEW

1.1 Clear River Energy Center

Invenergy Thermal Development LLC (Invenergy) is an independently owned company that develops, owns, and operates power generation and energy storage facilities across North America and Europe.

Invenergy's expertise includes a complete range of fully integrated in-house capabilities, including Project Development, Permitting, Transmission, Interconnection, Energy Marketing, Finance, Engineering, Project Construction, Operations, and Maintenance.

To date, the Company has developed over 9,056 MW of utility-scale renewable and natural gas-fueled power generation facilities across the United States, Canada, and Europe, including more than 7,132 of projects in operation and over 607 MW under contract or in construction. Our portfolio also includes over 1,316 MW of projects developed and sold under Build/Transfer or Development/Transfer Agreements.

Invenergy Thermal Development LLC is requesting approval from the Rhode Energy Facility Siting Board (RIEFSB) to construct and operate the Clear River Energy Center,("CREC") a combined-cycle electric generating facility to be located at the Spectra Energy Algonquin Compressor Station site on Wallum Lake Road (State Route 100) in Burrillville, Rhode Island (the Project or the Facility). The Project will provide many benefits to the region including reduced air emissions and improved air quality, lower regional energy costs, employment for skilled local workers during construction and operation, as well as direct economic benefits to the Town of Burrillville and to local businesses.

The Facility being proposed will participate in the ISO New England Forward Capacity Market in order to address need for new capacity that has been created by retirements of existing generators and the additional potential retirements of other generators in the New England market. The benefits associated with the Facility include:

1. Location: The Facility is located on a site with the Town of Burrillville is that is part of a larger parcel of land that includes both gas pipelines and electricity transmission lines each of which have adequate capacity to support the Project without requiring additional costly (and controversial) laterals for each.
2. Compliance with EPA's Clean Power Plan: The proposed design of the Facility complies with the EPA's recently announced Clean Power Plan requirements as they relate to types of technologies needed in order to improve air quality and reduce emissions.
3. Modernize and replace aging infrastructure: the facility will be the most efficient power generator in the New England market to date and will replace older, more polluting, less efficient modes of power generation that the region currently relies upon.
4. Other Environmental benefits: The Facility will help clean up a currently contaminated well in Burrillville that the Town has not been able to remediate. The cleanup will be accomplished by installing a treatment system and utilizing the treated water in the Facilities steam cycle.

The Facility will be configured as a two-unit one-on-one (1x1), duct fired, combined cycle generation station. Each unit will consist of an advanced class (G-, H-, or J-class) gas turbine operated in a combined-cycle configuration with a heat recovery steam generator (HRSG) equipped with natural fired duct burners and one steam turbine. The combustion turbine, steam turbine, and generator of each unit will be connected via a common shaft (otherwise referred to as a single shaft machine). Each gas turbine will fire natural gas as a primary fuel and ultra-low sulfur diesel (ULSD) fuel as a backup fuel from two-1,000,000 gallon on-site storage tanks for limited periods when natural gas is unavailable. ULSD will be delivered to the Facility by truck. The natural gas supply for the Facility will be provided by a pipeline from the adjacent Spectra Energy Algonquin Compressor Station.

The Facility will have a nominal power output at base load of approximately 850-1,000 megawatts (MW) while firing natural gas (with supplementary HRSG duct firing) and 650-800 MW while firing ULSD. The electrical power generated by the Facility will be transmitted through a new 345-kV transmission line to be installed from the Facility through an existing National Grid right-of-way (ROW) to the Sherman Substation.

Each unit will utilize air-cooled condensers (ACC) to limit water usage and wastewater discharge. The water supply for the Facility will be provided by the Pascoag Utility District (PUD) through a dedicated pipeline to be installed from the PUD water supply well field to the Facility. Wastewater from the Facility will be discharged to the Burrillville Wastewater Treatment Facility for treatment through a dedicated sewer line to be installed.

The Facility will be equipped with state-of-the art air emissions control and sound abatement systems. It has been designed to minimize and avoid impacts to the environment to the greatest extent technologically and economically feasible for such a facility. This will be assured by the numerous environmental permits that need to be obtained for the Project, and as detailed in this application.

1.2 Jurisdiction of the Rhode Island Energy Facility Siting Board

This application is being submitted to satisfy the applicable requirements of Rhode Island General Laws 42-98-1 et seq., the Energy Facility Siting Act (the Act). Section 4 of the Act states that "No person shall site, construct, or alter a major energy facility within the state without first obtaining a license from the siting board pursuant to this chapter." A major generating facility is defined as a facility to be used for the generation of electricity designed or capable of operating at a gross capacity of 40 megawatts or more. The RIEFSB application filing requirements and associated procedures for a major generating facility are established in the "State of Rhode Island and Providence Plantations Energy Facility Siting Board Rules of Practice and Procedure, April 11, 1996."

1.3 Application Organization

This application is complete and contains all of the information required by the RIEFSB Rules of Practice and Procedure, Section 1.6 as follows:

- Section 2.0 - Identifies the Applicant, the primary Project Contacts and the entities which make up the Project Team
- Section 3.0 - Provides a detailed Project Description
- Section 4.0 - Provides information on the Project Cost, the Project Schedule, and the Project Financing Plan
- Section 5.0 - Details the Project Benefits, including Community and Economic Benefits and local and Regional Environmental Benefits
- Section 6.0 - Includes an Assessment of the Environmental Impacts of the Project
- Section 7.0 - Provides an Assessment of Need for the Project
- Section 8.0 - Provides Evidence of how the Project conforms to Rhode Island Energy Policy
- Section 9.0 - Details the Life Cycle Management Plan for the Project
- Section 10.0 - Includes a Study of Alternatives for the Project
- Section 11.0 - Details the Status of Environmental Permits for the Project

Pertinent supporting documentation has been provided in Tables, Figures, and Appendices. A complete list of application requirements and the location of where that requirement is met can be found in Appendix J.

TAB 3

2.0 IDENTIFICATION AND DESCRIPTION OF APPLICANT AND AFFILIATES

2.1 The Applicant

Invenergy is an independently owned company that develops, owns, and operates power generation and energy storage facilities across North America and Europe.

Invenergy's expertise includes a complete range of fully integrated in-house capabilities, including Project Development, Permitting, Transmission, Interconnection, Energy Marketing, Finance, Engineering, Project Construction, Operations, and Maintenance.

To date, the Company has developed over 9,056 MW of utility-scale renewable and natural gas-fueled power generation facilities across the United States, Canada, and Europe, including more than 7,132 MW of projects in operation and over 607 MW under contract or in construction. Invenergy's portfolio also includes over 1,316 MW of projects developed and sold under Build/Transfer or Development/Transfer Agreements.

Invenergy's senior executives - each with more than 25 years in the energy generation industry - have worked together for over two decades. Invenergy's founder, president, and CEO, Michael Polsky, is a recognized and respected industry leader and is the majority owner of Invenergy and its affiliated companies.

Invenergy values integrity, commitment to business partners and host communities, and environmental responsibility. Furthermore, as an independently owned company and with a staff that is the best in the business – Invenergy operates nimbly and efficiently, delivering long-term growth.

Invenergy headquarters are in Chicago with regional offices in Denver, Toronto, Mexico City, Warsaw, and Tokyo.

2.2 Primary Contacts

All correspondences and communications concerning the Clear River Energy Center's Rhode Island Energy Facility Siting Board Application should be addressed to the Primary Contacts Identified below:

Project Manager	John E. Niland Director of Business Development Invenergy Thermal Development LLC One South Wacker Drive Suite 1900 Chicago, IL 60600
Project Counsel	Joseph Condo Senior Vice President and General Counsel Invenergy Thermal Development LLC One South Wacker Drive Suite 1900 Chicago, IL 60600
Rhode Island Counsel	Alan M. Shoer & Richard Beretta Adler, Pollock & Sheehan One Citizens Plaza, 8th Floor Providence, Rhode Island 02903

Environmental Permitting Project Manager	Mike Feinblatt ESS Group, Inc. 100 Fifth Avenue, 5th Floor Waltham, MA 02451
Project Engineer	Roger Nagel HDR 5405 Data Court Ann Arbor, MI 48108

2.3 Project Team

Rhode Island Counsel – Adler Pollock & Sheehan, P.C.

Adler Pollock & Sheehan (AP&S) is a New England law firm representing local, national, and international clients in a wide range of complex legal matters. Since 1960, AP&S has been committed to providing clients with the highest levels of legal services through a wide variety of practice areas from four office locations: Providence and Newport, RI, Boston, MA, and Manchester, NH.

AP&S represents some of the largest energy utility companies in the United States with comprehensive advice to facilitate some of the largest (500 to 1,000 MW) and most efficient thermal energy projects in the region. AP&S provides the critical legal representation necessary to allow developer clients to secure the necessary environmental permits, energy facility siting approvals, real estate agreements, local municipal approvals, construction agreements, labor contracts, legislation and the required financing from investors.

Environmental Consultant - ESS Group, Inc.

ESS Group, Inc. (ESS) is a multi-disciplinary environmental consulting company with offices in East Providence, RI, Waltham, MA, Norfolk, VA, and Portsmouth, NH. Over the past 15 years, ESS has provided energy-consulting services for more than 14,000 MW of proposed power generation and more than 700 miles of proposed electric transmission.

ESS's experience includes licensing and permitting of a broad spectrum of generation and transmission facilities, from greenfield projects and re-powering of existing generation facilities to upgrades of existing transmission and storage assets. ESS supports energy facilities during operation with environmental compliance, multi-media monitoring, waste management, data collection, and reporting, and permits renewals. We also regularly conduct environmental due diligence for energy facility asset acquisition and divestiture.

Project Engineer - HDR Engineering

HDR specializes in engineering, architecture, environmental, and construction services. Founded in 1917, the company now operates out of 225 office locations around the world. HDR's integrated power development consulting services range from comprehensive owner's engineer services to site selection, environmental reviews, air quality evaluations, permitting support, transmission planning, feasibility analysis, plant layout, preliminary/final engineering, procurement management, construction management and operational start-up.

Noise Consultant – Michael Theriault Acoustics, Inc.

Michael D. Theriault of Michael Theriault Acoustics, Inc. (MTA) has provided environmental noise control consulting services to the North American electric power industry since 1998. His services include preparation of noise impact studies for owners and developers; implementation of large-scale noise control programs for architectural engineering firms; noise level compliance testing for constructors; and noise control due diligence reviews for municipalities and financial underwriters. MTA has advised clients on hundreds of energy facilities, ranging in size from one to 2,000 megawatts, many from conceptual design through final testing, using combustion turbine, wind turbine, biomass, and conventional fossil-fueled technologies.

Cultural Consultant - Gray & Pape

Established in 1987, Gray & Pape is a national consulting firm specializing in cultural resources management and historic preservation services. Gray & Pape has conducted more than 1,500 projects and established a reputation for understanding the intricacies of the CRM process. Headquartered in Cincinnati, OH, the firm maintains offices in Indianapolis, IN; Richmond, VA; Providence, RI; and Rabbit Hash, KY, and qualifies as a Small Business Enterprise (SBE).

The professional staff at Gray & Pape includes individuals with experience in all phases of cultural resources studies, from archival research and analysis of cultural landscapes, to archaeological and architectural site survey. Their staff meets or exceeds the professional standards for historians and archaeologists outlined in the Secretary of the Interior's Standards and Guidelines for Archeology and Historic Preservation.

EMF Consultant - Exponent

Exponent is a leading engineering and scientific consulting firm with a staff of approximately 900, located in 20 offices throughout the United States and in 6 international offices. Exponent scientists and engineers provide advisory and consulting support to electric utilities, the telecommunications industry, the electronics industry, research organizations, and regulatory agencies. Exponent's consultants are involved with research studies involving electric and magnetic fields (EMF) and radiofrequency (RF) exposures. Research regarding the potential human health effects of exposure to EMF and RF forms the scientific basis for exposure limits and provides a firm basis for the safe use of these technologies. Their projects address potential risks to human health by conducting exposure assessments, epidemiologic studies, and evaluations of data to establish human exposure limits to EMF/RF.

Economic Consultant – PA Consulting

PA Consulting Group, Inc. is an independent, employee-owned, global consultancy with over 2,500 people across 30 offices. Founded in 1943, PA has extensive experience supporting businesses and governments worldwide and blends creative thinking with leading-edge expertise to solve today's most pressing and complex challenges. PA's experts are supported by over 250 scientists, technologists, and engineers that allow us to deliver more than just great thinking – we have proven hands-on experience of bringing innovative ideas and technology to market.

PA's Global Energy & Utilities practice helps their clients create markets, anticipate changes to their markets, use technology and IT to respond to regulator and customer demands, improve their reliability while reducing costs, and optimize investments. They work with regulators, policy makers, market and system operators, electric utilities, independent power producers, investment banks, private equity, and other clients to navigate through market uncertainty and prepare for operational change. They have extensive experience in U.S. power markets, having supported the development, acquisition, divestiture, or financing of over $100 billion in power generation assets since 2011 alone.

TAB 4

3.0 PROJECT DESCRIPTION AND SUPPORT FACILITIES

3.1 Facility Description

Invenergy Thermal Development LLC (Invenergy) is requesting approval from the Rhode Energy Facility Siting Board (RIEFSB) to construct and operate the Clear River Energy Center (CREC), a combined-cycle electric generating facility to be located at the Spectra Energy Algonquin Compressor Station site on Wallum Lake Road (State Route 100) in Burrillville, Rhode Island (the Project or the Facility). The Project will provide many benefits to the region including reduced air emissions and improved air quality, lower regional energy costs, employment for skilled local workers during construction and operation, as well as direct economic benefits to the Town of Burrillville and to local businesses.

The Facility will be configured as a two-unit one-on-one (1x1), duct fired, combined cycle generation station. Each unit will consist of an advanced class (G, H, or J class) gas turbine operated in a combined-cycle configuration with a heat recovery steam generator (HRSG) equipped with natural gas fired duct burners and one steam turbine. The combustion turbine, steam turbine, and generator of each unit will be connected via a common shaft, (single shaft). Each gas turbine will fire natural gas as a primary fuel and ultra-low sulfur diesel (ULSD) fuel as a backup fuel for limited periods when natural gas is unavailable. The ULSD will be stored in two 1,000,000-gallon on-site storage tanks. ULSD will be delivered to the Facility by truck. The natural gas supply for the Facility will be provided by pipeline from the adjacent Spectra Energy Algonquin Compressor Station.

The Facility will have a nominal power output at base load of approximately 850-1,000 megawatts (MW) while firing natural gas (with supplementary HRSG duct firing) and 650-800 MW while firing ULSD. The electrical power generated by the Facility will be transmitted through a new 345-kV transmission line to be installed from the Facility within a short section of new ROW and the existing National Grid right-of-way (ROW) to the Sherman Substation.

Each unit will utilize air-cooled condensers (ACC) to limit water usage and wastewater discharge. The water supply for the Facility will be provided by the Pascoag Utility District (PUD) through a dedicated pipeline to be installed from the PUD water supply well field to the Facility. Wastewater from the Facility will be discharged to the Burrillville Wastewater Treatment Facility for treatment through a dedicated sewer line to be installed.

3.2 Purpose and Function

CREC is proposed to help the New England Independent System Operator (ISO-NE) meet its capacity, reliability, and operational requirements and needs for the regional electric transmission network. Additionally CREC will provide many benefits to the region including:

- Provide new, highly advanced generating technology that will be one of the most efficient generators in New England, helping lower regional energy costs
- Reduce regional air emissions by displacing older, less efficient and more polluting generation and improve air quality through Best Available emission control technology
- Modernize the electric generating infrastructure by providing new, highly efficient generation that has fast start and high ramp rate (flexible) generating capability, replacing older, less flexible generation. The fast start and flexible generating capability will also help support the integration of new and existing renewable generation onto the power grid
- Utilize previously unusable Pascoag Utility District (PUD) water supply wells, which were shut down and deemed unsuitable for drinking water purposes more than ten years ago due to contamination, by installing a ground water treatment system that will help facilitate the remediation of the contamination

- Create new employment for skilled local workers during construction and operation, as well as direct economic benefits to the Town of Burrillville and to local businesses

The restructuring of New England's electric power industry in the late 1990s created an open, competitive wholesale electricity marketplace that is managed by the ISO-NE. The marketplace allows the ISO-NE to secure sufficient electricity and related services for the region at the lowest prices. The ISO operates a Forward Capacity Market to ensure the reliability of the New England power supply and assign Forward Capacity Obligations (FCO) to Generation Suppliers. Invenergy will offer CREC into upcoming Forward Capacity Auction(s), and once CREC is awarded an FCO, Invenergy will construct the Project.

Rising costs associated with oil and coal, the lower cost of natural gas combined with the advanced age of many of the power plants that use these fuels make it difficult for these resources to compete against newer, more efficient generators—primarily natural gas units. For this reason, coal and oil units are now run mainly to meet peak demand, when natural gas plants are unavailable, or when natural gas price spikes surpass oil prices. The region's coal- and oil-fired generators represent about 28% of capacity in the region, but only produced about 6% of its electricity in 2014. Almost all of the existing coal and oil facilities are close to or beyond their original design life. Additionally, most of these existing units are not located in an area where the existing natural gas supply infrastructure has adequate capacity to support their conversion to combined cycle technology. As a result, new units are being proposed in locations where sufficient supply of natural gas can be assured.

The performance of many existing fossil fuel power plants can be uncertain when called on, due to age and infrequent operation, posing risks to reliability. For example:

- Equipment issues can affect their performance when dispatched. Unexpected outages of older or poorly maintained units tend to increase during extreme cold conditions.
- They have long start-up times. In some instances, up to 24 hours are needed to reach full output, which makes it difficult for ISO operators to rely on these resources.

Additionally the Facility will help meet the needs of the region by being able to replace the capacity that will be lost by the recently announced retirement of the Pilgrim Nuclear Station by Entergy.

Regional power markets have shifted in recent years in response to fast-changing supply and demand parameters. The Independent System Operator-New England (ISO-NE) regional transmission organization have identified issues in their capacity market designs that have led to inadequate peak generation capacity or failed to provide appropriate incentives for investment in flexible capacity. In region, these problems have resulted in high-profile "narrowly missed catastrophic events" that have spurred market design changes.

The most significant of these proposals has been the new Pay-for-Performance Initiative (PI) that alters how a generation resource's capacity payments are calculated. Approved in May 2014, the PI will influence bidding behavior in the market beginning in 2018. Capacity payments in ISO-NE will be subject to a two-settlement process, including a capacity base payment and an additional capacity performance payment that redistributes penalty payments from underperforming resources to over performing resources. These capacity performance payments will be allowed to be negative, creating a substantial financial penalty for underperformance in scarcity conditions.

In the long term, PI will result in a more efficient, flexible fleet with lower energy prices. Under the new regime, new, efficient units can meet this need based on their flexibility and low forced outage rates and less reliable and more inflexible oil/gas steam-fired units, that cannot respond to the market signals in a timely fashion, (as such reduce reliability) will potentially be penalized. This relative advantage will likely result in accelerating the retirement of oil/gas steam capacity and incentivizing the construction of new, efficient units. In the long run, this dynamic should result in lower energy prices in ISO-NE, as more efficient units displace less economic

generation. In the near- to medium-term though, the dynamic could result in periods of capacity shortfall and price spikes if the transition is not orderly.

Rhode Island ranks 7th highest in average price of electricity to end-use customers in the nation. Rhode Island residential consumers pay about 35 percent more for electricity than the national average. In addition, the price of electricity for industrial use is 64 percent higher in Rhode Island compared to the national average. This puts Rhode Island businesses and industries in a disadvantageous cost-position to compete across the nation and reduces disposable income for Rhode Island residents.

Table 3.2-1
Average Price of Electricity to Ultimate Customers
July 2015, Cents per Kilowatt hour

Sector	*Rhode Island* Average Price	Rank	*U.S* Average Price
Residential	17.59	8	12.98
Commercial	14.00	9	11.06
Industrial	11.96	6	7.3
All Sectors	15.37	7	10.96

Source: U.S. Energy Information Administration, Form EIA-826, Monthly Electric Sales and Revenue Report with State Distributions Report.

According to estimates produced by the PA Consulting group, the development, construction, and operation of CREC is expected to result in a reduction of electricity prices for end-use consumers. From 2019 to 2022, cumulative savings to the Rhode Island customer resulting from electricity prices are projected to be over $280 million, or approximately $70m annually. This represents significant savings to Rhode Island ratepayers.

The EPA's Clean Power Plan, (CPP) calls for reductions in emissions and an increase in regional renewable generation. There are several ways in which to do this, but given New England's already high cost for energy, the implementation of the CPP must be accomplished in a cost effective manner. Renewable resources, such as solar and wind, create challenges for grid operators due to their intermittent and variable nature. They can have rapid and sizeable swings in electricity output due to wind speed, time of day, cloud cover, haze, and temperature changes—hence why they are called variable or intermittent resources. The ISO-NE recognizes the variable nature of these resources and states in their 2015 Regional Electricity Outlook that" *Wind and solar resources will eventually help achieve federal and state environmental goals. Paradoxically, the operating characteristics of these renewable resources which are different than traditional power plants will increase reliance on fossil-fuel-fired natural gas generators."* This is because intermittent resources are not dispatchable on demand and, as such, have a limited ability to serve peak load. Wind speeds can be at their lowest levels in the summer, while extreme cold and ice can also hinder output. Widespread use of solar power, meanwhile, will likely shift peak net load to later in the afternoon, just as output diminishes with the setting sun.

The New England ISO needs to balance the variable output from wind and solar resources, in order for the power system to operate properly. In order to do this, the ISO must hold generating units in reserve, or have access to units that have highly flexible operating characteristics that allows them to adjust output to meet changing conditions. This means that the generation fleet needs to evolve as more renewables are added. This includes the ability of generators to react to rapid and sizeable swings in electricity output as well as having additional fast-start capacity held in reserve.

CREC has the necessary characteristics to meet the challenges of a renewable future. Units like CREC cannot be considered independent or in lieu of renewables, but rather necessary in order to support the further development and addition of renewables as a crucial part of the solution to the regional efforts to meet the Clean Power Plan goals as well as the Rhode Island State Energy Policy.

The CREC will use a dry cooling system by using an air-cooled condenser, (ACC) which is similar to the cooling provided by a typical automobile radiator, which cools by the use of ambient air supplied by fans. The use of an ACC reduces the amount of water by approximately 90% compared to a conventional wet cooling tower. The use of a dry cooling system also reduces the amount of wastewater generated by the Project. Through its proposed use of an ACC, CREC is able to develop and utilize the proposed installation of the treatment system at PUD's closed well. Through the installation of the treatment system, CREC's use and cleaning of the groundwater will eventually lead to complete remediation of the groundwater as an additional environmental benefit of the CREC.

Economic development benefits associated with CREC will result from the following three areas:

1. Construction of the facility – Equipment, materials, and skilled labor employed during construction as well as, permitting fees, and other activities.
2. Ongoing operation of the facility – Fixed and variable costs associated with the materials and labor needed to operate the facility as well as annual property taxes.
3. Power market cost savings to Rhode Island ratepayers – The addition of new efficient generation capacity in Rhode Island will result in lower capacity and power prices in the near term, thereby driving significant savings to Rhode Island ratepayers during the plant's early years.

In terms of economic impact, Section 5 below includes the detailed estimates that from 2017 to 2018 the construction of the CREC will support the creation of new construction jobs and generate approximately $100 million/year in income for Rhode Island residents. Upon conclusion of the construction phase, ongoing facility operations and expenditures will support approximately 250 jobs/year in the state. Therefore, CREC construction and operation produces significant economic benefits to Rhode Island residents including lower energy prices, jobs, and income.

3.3 Land Area

The CREC site is located in a forested, predominantly rural area. The 67 acres of land area will be purchased from the Spectra Energy Algonquin Compressor Station site ("Spectra") and is a subset of a 730-acre site that Spectra owns that currently contains the Burrillville Compressor Station. The Facility will be constructed just south of the existing compressor station. The Algonquin Gas Compressor Station is surrounded by dense vegetation. The CREC will require a new access road which will be located south of, and parallel to, the existing Algonquin Road. The closest residents are approximately 2,300 feet to the north of the north-northeast corner of the property line.

3.4 Site Plan

Figure 3.4-1 is an aerial photograph of the existing site. Figure 3.4-2 is a locus map showing the location of the site. Figure 3.4-3 provides the proposed site plan.

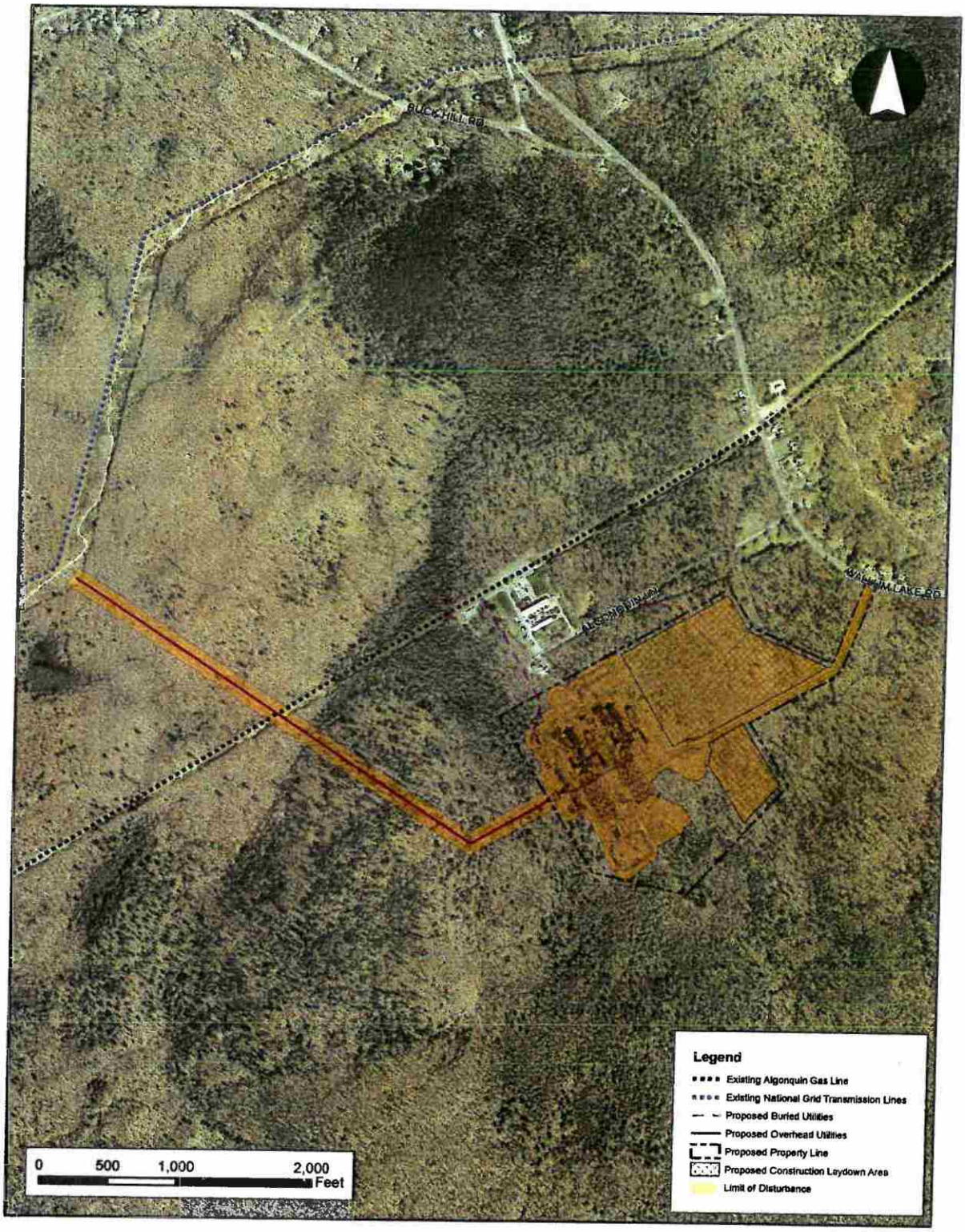

Figure 3.4-1
Site Layout

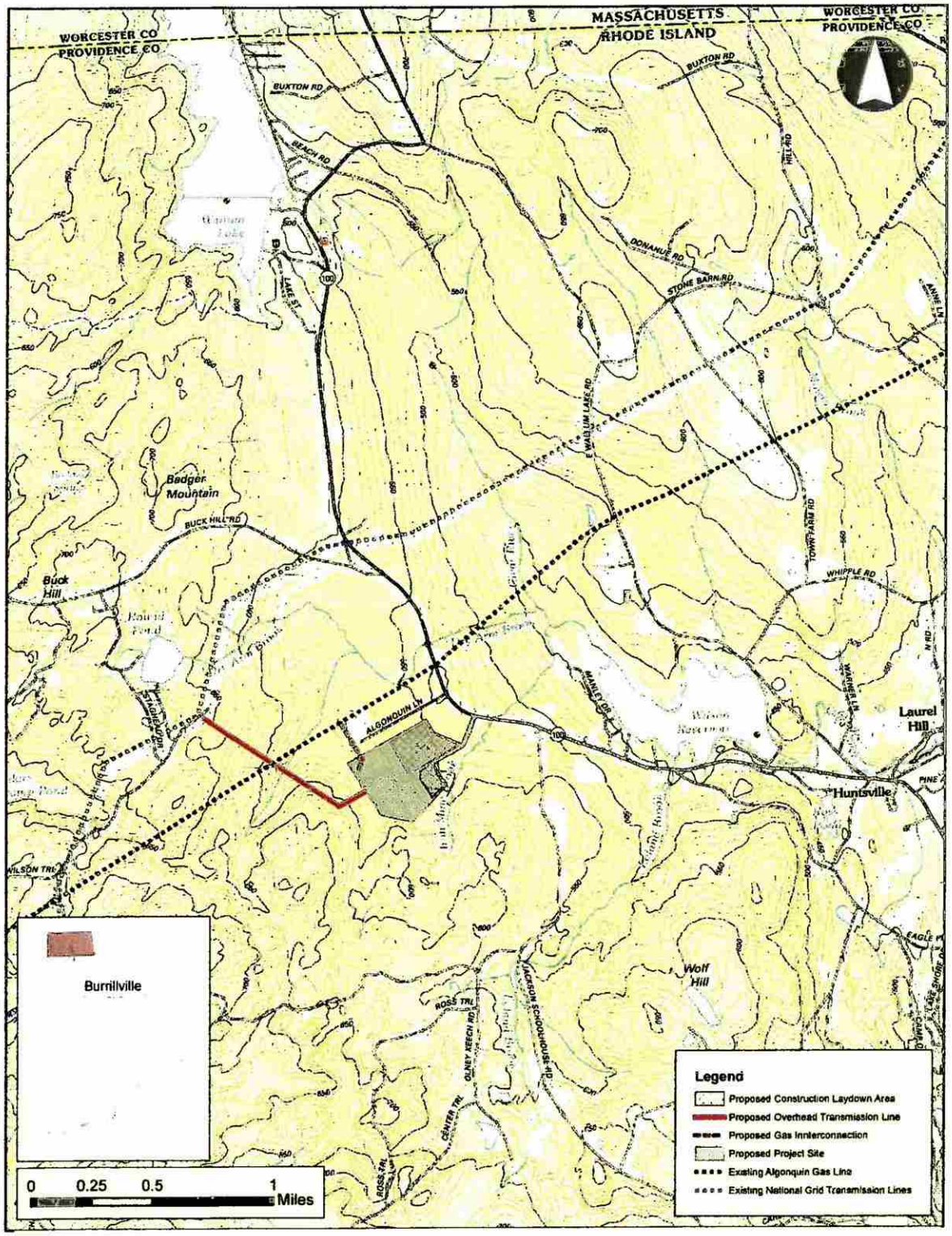

Figure 3.4-2
Site Locus

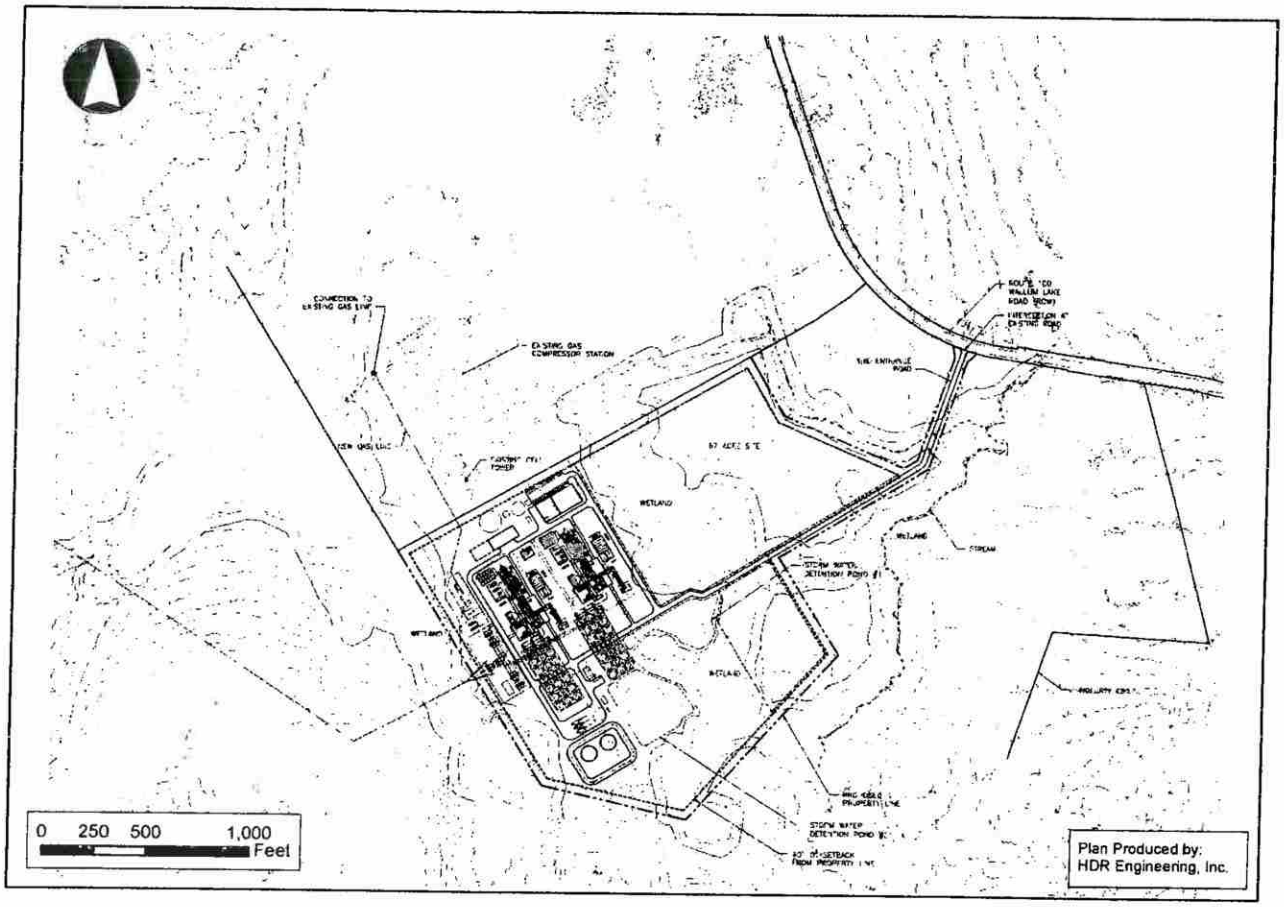

Figure 3.4-3
Site Plan

3.5 Structures

3.5.1 Primary Powerhouse Building

Each single-shaft, 1x1 combined cycle power train will be enclosed in a powerhouse building. The building will be designed to enclose the combustion turbine, steam turbine, single-shaft generator and associated ancillary equipment. The primary structure of this building will be approximately 150ft long, 94ft wide, and 80ft tall and will include an overhead crane to facilitate equipment maintenance activities as well as equipment laydown areas for maintenance. A drive-through access road through this portion of the building will be available for component delivery and removal. In addition, the structure will include balance of plant equipment such as condensate pumps, air compressors, drains tanks and other equipment.

The combustion turbine exhaust will exit the north-west end of the building into a heat recovery steam generator and stack, and the steam turbine exhaust will exit the southeast end of the building via an exhaust duct to each ACC.

The powerhouse building will be constructed of a steel structure with acoustically attenuated siding for noise control. The building and internal equipment components will be supported by suitable concrete foundations (mat, spread footing, etc.) bearing on existing soils or supported on deep foundations (piles, caissons, etc.).

3.5.2 Smaller, Auxiliary Buildings, Fuel Oil Equipment, and Electrical Equipment Buildings

In addition to the Primary Powerhouse buildings, the Facility will include the following smaller buildings:

- Administration and Controls/Warehouse Building – The administration and control portion of this building will house the plant control room, offices and meeting rooms for plant staff, locker rooms, restrooms, lunchroom, and service rooms for communications, electrical, control, and mechanical systems. The warehouse portion of the building will include an area to store spare parts, and a workshop area for performing maintenance of small equipment (such as motors and pumps).
- Auxiliary Boiler Building – This building will house the natural gas fueled auxiliary boiler to supply steam to the HRSGs during certain operating conditions (discussed in Section 9.1.2.2). The auxiliary boiler building is located between the HRSGs of each unit. The Facility will have one auxiliary boiler installed in a building.
- Fire Pump Building – This building will house the diesel fueled fire pump.
- Feed Water Pump Building – Boiler feed water will be supplied to the individual HRSGs by multiple large feed water pumps located in this building. This building will also include the closed cooling circulating water pumps and a water sampling station. Each unit will include a dedicated feed water pump building.
- Water Treatment Building – Water filtration and demineralization equipment will be located in the water treatment building.
- Gas Compressor Building – The Facility gas compressor will be installed in this building. Natural gas will be compressed to satisfy the combustion turbine inlet pressure requirements.
- Fuel Oil Equipment Building – Equipment required to operate and maintain back up fuel oil operations shall be located in the fuel oil equipment building

3.5.3 Storage Tanks

The Facility will include the following storage tanks:

- Fuel Oil Storage Tanks - The Facility will include two 1,000,000 gallon above ground ULSD storage tanks equipped with secondary containment, as required by law. These welded steel tanks will be approximately 30 feet tall and 80 feet in diameter.
- Demineralized Water Storage Tank – The Facility will include one demineralized water storage tank with approximately 1, 000,000-gallon storage capacity. The tank will be approximately 30 feet tall and 110 feet in diameter. This storage capacity will provide water for approximately 10 days of continuous operation on natural gas at summer conditions.
- Waste Water Storage Tank – Blowdown from the HRSGs, evaporative coolers, and other wastewater from the Facility will be collected in an approximately 160,000-gallon waste water storage tank. The tank will be approximately 30 feet tall and 30 feet in diameter.
- Fire Water / Service Water Storage Tank – Plant service water /fire water will be stored in a tank with a storage capacity of approximately 800,000 gallons. The tank will be approximately 30 feet tall and 68 feet in diameter.
- Ammonia Storage Tank – Part of the plant emissions control systems will include selective catalytic reduction systems for controlling NO_x emissions in the HRSGs. The SCR systems will use ammonia as a reagent. Aqueous ammonia will be stored at a concentration less than 20% in a storage tank with a storage capacity of approximately 40,000 gallons.

3.5.4 Switchyard

Each 1x1 combined cycle unit will have a generator step-up (GSU) transformer to increase the voltage from the generator voltage to 345kV. The GSU transformers will be connected to the Facility switchyard located along the western edge of the site via underground cable duct banks. The Facility switchyard will occupy a footprint of approximately 370 feet by 155 feet and will be configured as a 345kV three-breaker collector bus switchyard. The switchyard will be separately fenced and will include a separate enclosure for control equipment and auxiliary power systems. An overhead 345kV transmission line exits the switchyard and runs along new and existing right of way (ROW) interconnecting at the National Grid Sherman Road Switching Station.

3.5.5 Appurtenant Equipment

The following is a list of appurtenant equipment and systems:

- Standby diesel generator – The Facility will include a 2 MW standby diesel generator.
- Natural gas system - A natural gas fuel yard will be installed at the Facility that includes fuel gas filters, fuel gas dew point heaters, gas regulation trains and flow meters, and a gas compressor.
- Duct burner fuel skids – Each HRSG will be equipped with a dedicated natural gas control and regulation skid to reduce pressure and measure and modulate gas flow to the duct burners.
- Hydrogen tube trailer – The unit generators will use gaseous hydrogen for cooling and heat rejection. Truck trailer mounted hydrogen tube racks will be used for on-site hydrogen storage and makeup to the generators. Alternately, a hydrogen generator may be used for this purpose.
- Waste water collection – Wastewaters generated by the Facility will be collected and pumped via a forced main to a connection with the Burrillville Sewer Authority wastewater treatment system. Alternately, a zero liquid discharge system may be used.
- BOP Electrical – Balance of plant electrical systems (medium and low voltage transformers, switchgear and distribution systems) will be installed in an enclosure adjacent to each combined cycle unit. These systems will be energized by the station auxiliary transformers that will reduce voltage from the generator voltage to the appropriate medium voltage.

3.5.6 Cooling Systems

The Facility has been configured to use dry-type heat rejection systems using an ACC. Each combined cycle unit will have a dedicated ACC and associated subsystems and piping. Steam turbine exhaust steam will be ducted through large horizontal ducts feeding several vertical risers on each ACC. Each riser will deliver steam to a distribution manifold that will run horizontally along the top of a row of finned tube air-cooled heat exchangers arranged in an A-frame configuration. Fans will be used to move ambient air over the finned tubes causing the steam to condense releasing heat to ambient air and the condensate will be drained back to the condensate collection system. Each ACC will occupy a footprint of approximately 350 feet by 150 feet and be approximately 120 feet tall.

The facility will also include air cooled closed cycle cooling water heat exchangers (one for each combined cycle unit) to reject heat from various auxiliary systems such as lube oil and hydrogen cooling. The heat exchanger will use fans to move ambient air over the finned tubes carrying the hot closed cycle cooling water.

3.5.7 Transmission Facilities

The Facility will connect to the National Grid electric utility system at the Sherman Road Switching Station as determined from a recently completed feasibility study conducted by ISO New England (ISO-NE). The transmission line will be installed and owned by National Grid as part of the generation interconnection

application process. Connection to the Sherman Road Switching Station will be via a new 6-mile long 345kV transmission line that will be constructed. The transmission line will run west from the CREC switchyard along a new right of way to the two existing 345 kV transmission lines north-west of the Facility. The new transmission line will run on new towers set within the National Grid right of way from a point north-west of the Facility to the Sherman Road Switching Station.

3.6 Transmission and Interconnection

The Facility will connect to the National Grid Sherman Road Switching Station via a new 6-mile long 345kV transmission line. In addition, the 345kV Sherman Road Switching Station will also be expanded to add a breaker to accommodate the new transmission line connection and generation capacity addition. Other transmission system improvements proposed to accommodate the interconnection include upgrades to Line 3361, a 10.8-mile line from the Sherman Road Switching Station to ANP Blackstone with a minimum (NOR/LTE/STE) rating set of: 1400/1685/1685 MVA.

3.7 Underground Construction

Underground construction will include concrete foundation substructures as well as site utility piping for water, natural gas, fuel oil, and electrical cables. The Facility will include underground duct banks to route high voltage electrical cables at 345kV to connect the two Generator Step Up transformers to the Facility switchyard.

3.8 Environmental Controls

3.8.1 Air Emission Controls

The Facility will utilize state-of-the-art air emission controls. Each gas turbine/HRSG will be equipped with a Selective Catalytic Reduction (SCR) system for the control of nitrogen oxides (NO_X) and an oxidation catalyst for the control of carbon monoxide (CO), volatile organic compounds (VOCs) and hazardous air pollutants (HAPs). Water injection will also be used during ULSD firing for NO_X emissions control. Emissions of carbon dioxide (CO_2), sulfur dioxide (SO_2), and particulate matter ($PM_{10}/PM_{2.5}$) from the gas turbines/HRSGs will be minimized by the use of clean burning, low sulfur, low ash fuels, and the most efficient gas turbine combustion technology commercially available.

NO_X emissions from the natural gas fired auxiliary boiler and dew point heater will be controlled by the use of ultra-low NO_X burners and flue gas recirculation (FGR).

3.8.2 Wastewater Discharge Controls

As discussed above, the Facility will use ACCs for cycle heat rejection, which will significantly reduce water use and the production of wastewater. Wastewater generated within the Facility will be segregated by area into separate wastewater streams according to the source of the wastewater. The primary sources of wastewater include process wastewater (primarily from the water treatment processes), general service water (general housekeeping floor and equipment drains) and sanitary wastewater.

Process wastewater sources needing pH adjustment will be treated by a wastewater neutralization system and wastewater from the general service system will collected and treated through an oil/water separator to remove oil that might be in drains from various pieces of equipment. Wastewaters generated from process wastewater and general service water sources will be collected and stored in an on-site wastewater storage tank.

The Project is in discussions with Town of Burrillville and the Burrillville Sewer Commission (BSC) to determine whether wastewaters from the Facility can be discharged and treated within the existing Burrillville Wastewater Treatment plant. If approved by BSC and RIDEM, periodically wastewaters collected within the Facility will be pumped via a force main to a sewer connection with the Burrillville Sewer Authority wastewater system.

3.8.3 Stormwater Discharge Controls

Stormwater management at the Facility will comply with the requirements of RIDEM's Rhode Island Stormwater Design and Installation Standards Manual (as amended March 2015). The Facility will meet the Minimum Stormwater Management Standards outlined in the referenced guidance document to the extent practicable. The proposed Project is new development and, therefore, Minimum Standard 6 (Redevelopment and Infill Projects) does not apply. Minimum Standards 1-5 and 7-11 will be met by the Facility's stormwater management program described below.

The majority of the Facility's improved surface area qualifies as a "Land Use with Higher Potential Pollutant Load (LUHPPL)" as defined in RIPDES Rule 31(b)(15)(vi) – Steam electric power generating facilities. Because of the required site arrangement, the Facility is ineligible for a No Exposure Certification for Exclusion from RIPDES Stormwater Permitting and accordingly a stormwater management program will be developed to comply with the criteria of the LUHPPL classification (where appropriate). Areas to be classified as LUHPPL will drain stormwater to a lined wet vegetated treatment system or filtering practice Stormwater BMP approved for use at LUHPPLs. Infiltration practices will not be proposed in LUHPPL areas.

Portions of the Facility site that are not classified as LUHPPLs include the administration building, parking area, and the site's proposed access road. These areas will drain stormwater to proposed infiltration basin BMPs as applicable based on tested infiltration rates.

Regardless of pollutant load classification, low impact development (LID) strategies will be employed to the maximum extent practicable to reduce the generation of stormwater runoff from the Facility. Please refer to Section 6.4 for more information on proposed LID strategies. Non-LUHPPL areas will achieve groundwater recharge in post-developed conditions in the same watershed as pre-developed conditions through the use of infiltration BMPs. Pollutant reduction of stormwater (water quality Minimum Requirement) will occur from the use of wet vegetated treatment systems or filtering practices (LUHPPL areas) and infiltration (non-LUHPPL areas). Conveyance facilities, natural channels, and overbanks will be sized and designed to protect them from stormwater flows in accordance with RIDEM standards.

Source control and pollution prevention measures will be employed to minimize adverse water quality impacts from Facility runoff. A Stormwater Pollution Prevention Plan (SWPPP) and Soil Erosion and Sediment Control (SESC) Plan will be developed in accordance with provisions of the Rhode Island Soil Erosion and Sediment Control Handbook and best practices. Illicit discharges are prohibited under a National Pollutant Elimination Discharge Elimination System (NPDES). The Facility is designed to fully separate stormwater from other wastewaters including sanitary wastewater. Following construction the Facility designs will be conformed to as-builts, in part, to ensure that no illicit connections occurred. A stormwater management system operation and maintenance program will be developed and included as part of the stormwater management program. The operation and maintenance program will be implemented at the Facility following termination of coverage under construction stormwater permits.

3.8.4 Noise Controls

As summarized in Table 3.8-1, the proposed acoustical design of the Project includes extensive noise attenuation features.

Table 3.8-1

Proposed Acoustical Design

Equipment Item	Control
Air Cooled Condenser	Low-Noise Design
Auxiliary Boiler	Enclosed within a Building
Auxiliary Boiler FD Fan Intake	High-Performance Duct Silencer Banks
Auxiliary Boiler Louvered Ventilation Openings	Acoustical Louvers
CCW Heat Exchanger	Low-Noise Design
Combustion Turbine Air Intakes	High-Performance Air Intake Silencers
Combustion Turbine	Enclosed within a Building
Combustion Turbine Ventilation	Ventilation System Silencers
Combustion Turbine Exhaust Diffusers	Exhaust Diffuser Noise Walls
Combustion Turbine Exhausts	Exhaust Mitigated via SCR/HRSGs and High-Performance Exhaust Stack Silencers
Fuel Gas Compressors	Enclosed within a Building
Generation Building Louvered Ventilation Openings	Acoustical Louvers
GSU Transformers	Low-Noise Design
HRSG Boiler Feedwater Pumps	Enclosed within a Building
HRSG Transition Ducts	Acoustical Shrouds
Steam-Turbine	Enclosed within a Building
Water Treatment Equipment	Enclosed within a Building

3.9 Identification of Support Facilities and Accessibility

3.9.1 Roads

The site access road connects the Facility to the Wallum Lake Road (Route 100). This road is designed as a Class A road to handle equipment loads during and after plant construction. The route of the road is shown on Figure 3.4-3.

3.9.2 Gas Line

Natural gas will be delivered to the Facility from the neighboring Spectra Energy gas compression station north of Algonquin Lane. Gas delivery pressure varies throughout the year and is estimated at about 450 – 800 psig .The Facility design includes natural gas compressors to boost and maintain gas pressure at levels necessary for gas turbine operation, dew point heaters, and other associated equipment identified in section 3.3.5. The preliminary route of the natural gas pipeline from the Spectra Energy compressor station to the Facility is shown on Figure 3.4-2.

3.9.3 Electric Transmission Lines

The electrical grid interconnection for the Facility will be at the National Grid Sherman Road Switching Station to the northeast of Burrillville, Road Island. The Project will include the construction of a new 345 kV overhead transmission line approximately 0.8 miles in length along a new right-of-way from the switchyard located at the Facility to the existing National Grid 345kV ROW located west of the Facility.

From this point, the new transmission line will run within the existing national Grid ROW approximately 6.0 miles to the Sherman Road Switching Station. The switchyard and the new transmission line are shown on Figure 3.4-3.

In addition, the 345 kV Sherman Road Switching Station will also be expanded to accommodate the new transmission line connection and generation capacity addition. There will also be upgrades to Line 3361, a 10.8-mile line from the Sherman Road Switching Station to ANP Blackstone.

3.10 Water Supply Pipeline

Water supplied to the Facility will be provided from the Pascoag Utility District (PUD) by re-activation and treatment of a currently inactive PUD groundwater well that became contaminated in 2001 by an off-site contamination source. As a result of this well-documented groundwater contamination event, PUD was forced to terminate is use of its primary well water supply and interconnect its water supply system with the Harrisville Fire District (HFD) to meet the requirements of its customers for potable water.

Because of that 2001 contamination event and the closure of PUD's primary groundwater supply, PUD currently receives approximately 88% of its water supply from the HFD under a wholesale water purchase agreement. PUD's average annual water demand today is approximately 0.3 MGD with a summer peak of approximately 0.35 MGD. PUD supplements the water supplied from HFD from PUD's only operating groundwater well (Well #5) which was not impacted by the 2001 contamination event. PUD's wholesale water supply agreement with the HFD is for a maximum supply of 0.6 MGD provided through PUD's Main Street interconnection with the HFD water supply system. Although PUD has a wholesale water agreement with the HFD for as much as 0.6 MGD, PUD currently only draws a portion of that maximum flow to meet its daily needs.

To meet the water supply requirements for the Facility, Invenergy and PUD will execute a water supply agreement that PUD will, on an exclusive basis, provide water treated to an industrial standard to the Facility from PUD's contaminated well water supply (well #3A). Water to be supplied to the Facility will be treated by an activated carbon treatment system producing water of sufficient quality for use in the Facility. This treated water will be supplied to the Facility in a dedicated water supply pipeline that will not be interconnected into the PUD potable water supply system; there will be no other users of this industrial water supply. None of this treated water intended for use by the Facility will be used as a potable water supply and none of the water produced by the carbon treatment system will be supplied to any other user in the community. Costs related to the treatment of the PUD contaminated supply will be covered entirely by the Facility under a long-term water supply agreement with PUD.PUD will secure, with the help of CREC, all of the required permits and authorizations to implement this water supply agreement.

The proposed Facility has been configured as a nominal 850-1,000 MW, energy efficient, dual-fuel combined cycle power plant that will utilize dry cooling to conserve water use. The Facility's daily water demand will vary considerably depending on plant load, ambient air temperature, and use of natural gas as a fuel. Additionally, if during the winter season natural gas supplies coming into New England are in short supply or constrained, the gas turbines can be fired by ultra-low sulfur distillate (ULSD), as requested by Independent System Operator New England (ISO-NE). This will also affect the Facility's daily water demand.

The Facility's daily water demand with both combustion turbines firing natural gas under full-load normal conditions will be approximately 104,000 gallons per day (gpd) or 0.104 million gallons per day (MGD),a full-load summer condition will be approximately 225,000 gpd, or 0.225 MGD assuming the evaporative cooler is running 24 hours a day. During the infrequent periods when the Facility is requested to fire one of the gas turbines on oil, the daily water demand for the Facility will increase to approximately 925,000 gpd, or 0.925 MGD for each day of oil firing. Although the total water use of the Facility increases when firing ULSD oil, the total number of days that the Facility will be required to fire oil will typically be determined by the grid operator (ISO-NE) based on the severity of winter conditions when there is a need to conserve natural gas for heating

needs of the region. Generally, based on history, the number of days per year the Facility will be requested to use ULSD will be approximately five days.

Water will be supplied to the Facility by PUD in a dedicated water supply pipeline that will extend from PUD's well water carbon treatment facility to the Facility site. Figure 3.10-1 provides a map of the planned route of the dedicated water supply pipeline. This dedicated water pipeline will be installed in existing public roads.

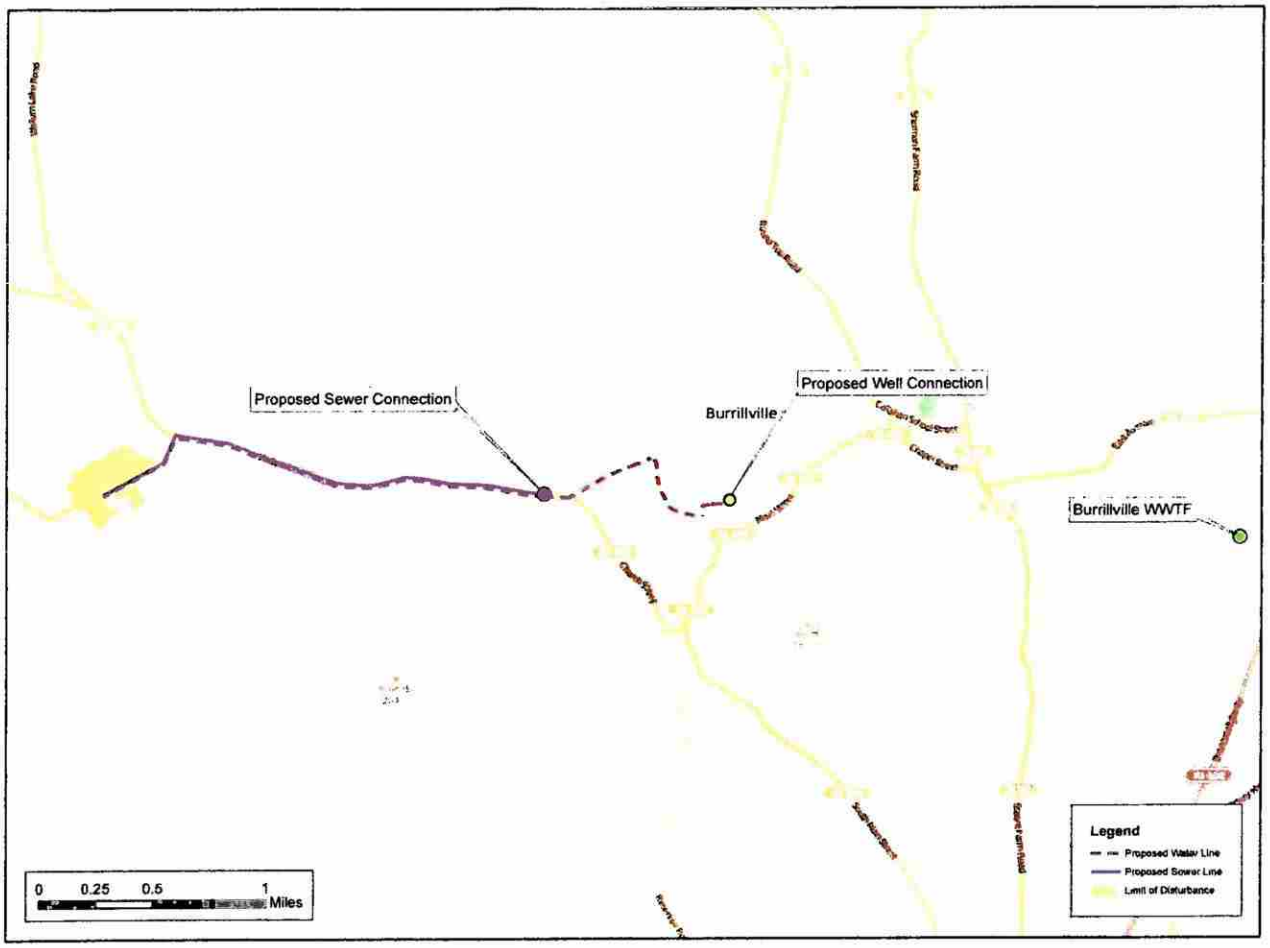

Figure 3.10-1
Water and Sewer Connection

3.11 Wastewater Sewer Pipeline

The Facility has been configured to use dry cooling to conserve its water use, which also reduces the total volume of wastewater generated by the Facility. The wastewater volume generated by the Facility will vary throughout the year depending on the operating load and ambient conditions. The typical daily flow will vary from 69,000 gpd to 89,000 gpd. During the infrequent times in the winter that the Facility is required to fire USD oil, the total wastewater volume discharge will be approximately 200,000 gpd.

The Project has held discussions with Town of Burrillville and the Burrillville Sewer Commission (BSC) to determine whether wastewaters from the Facility can be discharged and treated within the existing Burrillville Wastewater Treatment plant. The BCS has provided a letter of support, which is included in Appendix I. If approved by BSC and RIDEM, wastewater collected within the Facility will be pumped periodically via a force main to a sewer connection with the Burrillville Sewer Authority waste water system.

If the Project's wastewater can be accepted for discharge and treatment by the Burrillville Wastewater Treatment Plant, a dedicated force main sewer line will be installed from the Facility to an interconnection to the existing Town of Burrillville sewer system. Figure 6.2-1 provides a map of the planned route of the force main. The dedicated force main will be installed in existing roads to the point of interconnection to the existing Town sanitary sewer system.

TAB 5

4.0 PROJECT COST, SCHEDULE, AND FINANCING PLAN

4.1 Project Cost

Invenergy is privately funding the construction of the Project and will seek project financing from third party debt providers, as described below. This structure does not impose a burden on ratepayers but rather shifts the risks of costs for development and operations to Invenergy.

A brief summary of Invenergy's expected Project costs are set forth below. The Project is being privately financed, without ratepayer funds, and the power produced will be sold into the competitive ISO-NE market through a competitive bidding process.

In the previous EFSB decisions (e.g. Tiverton Power Associates, L.P., Docket SB-97-1 (March 25, 1998)) the EFSB explained that the requirements for a detailed cost analysis of the project are largely anachronistic after the restructuring of the wholesale electric industry implemented by the Utility Restructuring Act of 1996.

Therefore, a brief description of project cost is provided here. Should project costs proves uneconomic, the risk will be entirely placed on Invenergy and not on Rhode Island ratepayers. Also, as a result of the restructuring of the electric industry, and the competitive nature of the wholesale markets, detailed information on project cost structure is commercially sensitive and would put Invenergy at a competitive disadvantage, if disclosed to competitors

Equipment

- *Combustion Turbines and Generators*
- *Heat Recovery Steam Generators*
- *Exhaust Stacks*
- *Steam Turbine Generators*
- *Cooling and Related Systems*
- *Switchyard*

Total Equipment Cost Estimate: $350 Million

Construction and Other Costs

- *Development*
- *Design*
- *Construction*

Total Construction Cost Estimate: $350 Million

TOTAL ESTIMATED PROJECT COST: $700 Million

4.2 Project Schedule

Clear River Energy Center will be bidding into the NE ISO Forward Capacity Auction 10 on February 8, 2016 to support obligation to provide capacity to NE ISO beginning June 1, 2019. Invenergy began early stage development of the Clear River Energy Center with the execution of the site land option in December 2014.

Permitting and project development work is expected to continue into 2016. An Air Permit application was submitted to RIDEM on June 26 2015. Concurrently, industry-leading Equipment Manufacturers (OEM) and Engineering, Procurement, and Construction Contractors (EPC) were engaged to develop proposals for the Project. The selected OEM will be determined by November 13, 2015 and released under a Notice to Proceed (NTP) by May 2016. The selected EPC contractor will be released under a Limited Notice to Proceed (LNTP) by July 2016. The NE ISO Interconnection Agreement will be signed in April 2016. All other permits and approvals are expected to be issued by financial close in Q4 of 2016. Following financial close, the EPC will be released under a Full Notice to Proceed (FNTP) and will mobilize to site. Expected Substantial Completion dates for Units 1 and 2 are March 1, 2019 and May 1, 2019 respectively.

4.3 Financing Plan

Over the last 10 years, Invenergy has raised more than $15 billion to support its worldwide portfolio of 70 projects totaling over 9,000 MW that are operating or under construction. Invenergy is an experienced company that proficiently structures project financing and maintains strong relationships with banks in the United States, Canada, Europe, and Asia.

To illustrate Invenergy's financial capability, the Company was able to bring over 630 MW into operation in 2014 spanning across all technologies within Invenergy's expertise: wind, natural gas, storage and solar.

Invenergy would seek financial institutions that have an existing relationship with Invenergy to develop a more detailed approach to financing. Invenergy has successfully worked with the following institutions (in alphabetical order): Allstate, Associated Bank, BAML, Bayern LB, BNP Paribas, CoBank, Credit Suisse, Dexia, Deka Bank, GE EFS, HSH Nordbank, ING, John Hancock (Manulife), JP Morgan, Heleba, Macquaire Bank, MetLife, Mizuho, Morgan Stanley, Natixis, Nord LB, Prudential, Rabobank, RBC, RBS, Sabadell United Bank, Santander, Siemens, Sumitomo Mitsui Banking Corporation (SMBC), SunLife, UniCredit, Union Bank (now MUFG), US Bank, and Wells Fargo / Wachovia.

TAB 6

5.0 PROJECT BENEFITS

5.1 Economic Benefits

To characterize and evaluate the economic development impacts resulting from the construction and ongoing operation of the 1,000 MW Clear River natural gas-fired combined cycle generation facility, Invenergy retained the services of Professor Edinaldo Tebaldi and PA Consulting Group ("PA").

Dr. Tebaldi is an associate professor of economics at Bryant University. He also serves as the Rhode Island forecast manager for the New England Economic Partnership (NEEP). He is an applied econometrician with research interests in economic growth, development, and labor market outcomes. Dr. Tebaldi has published several articles in refereed journals and co-authored a number of economic impact assessment studies and reports analyzing economic conditions across New England States.

PA's Global Energy & Utilities practice regularly performs power market analyses and evaluates the economics of power generating assets across the U.S., including the New England power market. PA understands the economic development considerations associated with power generation investment and utility power procurement, and has used input-output models to evaluate the economic impacts driven by such decisions.

This subsection introduces the methodology and projected impacts on employment, wages, and the overall economy in Rhode Island and the surrounding area.

5.1.1 Overview

As is typically the case with generation facilities, CREC will drive significant economic impacts in the State of Rhode Island. Economic development impacts associated with the Project will result from the following three areas:

1. Construction of the facility – Equipment, materials, and labor employed during construction as well as state sales tax, permitting fees, and other activities.
2. Ongoing operation of the facility – Fixed and variable costs associated with the materials and labor needed to operate the facility as well as annual property taxes.
3. Power market cost savings to Rhode Island ratepayers – The addition of new efficient generation capacity in Rhode Island will result in lower capacity and power prices in the near term, thereby driving significant savings to Rhode Island ratepayers during the plant's early years. From 2019-2022, cumulative savings to the Rhode Island customer are projected to be greater than $280 million, or approximately $70m annually. PA has evaluated the induced economic effects on the Rhode Island economy associated with these near-term electricity customer cost savings.

5.1.2 Methodology

To estimate the magnitude of the resulting economic impacts, this study uses input-output (I-O) analysis. I-O analysis accounts for inter-industry relationships within a city, state, or expanded area, and employs the resulting economic activity multipliers to estimate how the local economy will be affected by a given investment (in this case the construction and ongoing operation of CREC).

Multiplier analysis is based on the notion of feedback through input-output linkages among firms and households who interact in regional markets. Firms buy and sell goods and services to other firms and pay wages to households. In turn, households buy goods from firms within the economic region. Thus, the economic impact of CREC spreads to other local businesses through direct purchases from them as well as from purchases of locally produced goods and services, which arise from the income derived by the employment that is created. Further impacts occur because of feedback effects – where other local firms require more labor and inputs to meet rising demand for their output, which has been stimulated by CREC construction and operation.

The economic impact of CREC construction and operation can be categorized as follows:

1. **Direct Effects** – Jobs, income, output and fiscal benefits that are created directly by the construction and ongoing operations of CREC. The jobs (and other benefits) that are created may be short-term, as in the case of construction jobs, or long-term, such as the operations and maintenance positions that exist throughout the life of the generation facility.
2. **Indirect Effects** – Jobs, income, output and fiscal benefits that are created throughout the supply chain and that are spawned by the direct investment to build and operate the facility. Indirect jobs include the jobs created to provide the materials, goods, and services required by the construction and operation of CREC, as well as the jobs created to provide the goods and services paid for with the wages from the direct jobs.
3. **Induced Effects** – Jobs, earnings, and output and fiscal benefits created by household spending of income earned either directly from CREC or indirectly from businesses that are impacted by CREC.

There is significant complexity involved in the calculation of these effects, particularly in the calculation of the indirect and induced effects, but comprehensive estimates of economic impacts require all three. These estimates are also sensitive to the set of assumptions considered in the study, principally assumptions regarding the leakage of economic activity outside the state. In addition, a series of variables, including changes to the price of electricity, will influence the multiplier benefit analysis and therefore have been considered in tandem to assess the true contribution of CREC to the Rhode Island economy.

5.1.2.1 Input-Output Models Employed

The job creation, earnings, and overall economic impact of CREC on Rhode Island have been analyzed using project cost specifics and two input-output models: IMPLAN and the National Renewable Energy Lab's Jobs and Economic Development Impact model (JEDI).

IMPLAN is an economic analysis tool that takes data from multiple government sources and employs an estimation method based on industry accounts or Input-Output Matrix that allows using multipliers to make estimations of how changes in income and spending impact the local economy. IMPLAN estimates are generated by interacting the direct economic impact of CREC with the Regional Input-Output Modeling System (RIMS II) multipliers for Rhode Island. The U.S. Bureau of Economic Analysis (BEA) provides these multipliers.

The Jobs and Economic Development Impact (JEDI) model estimates the economic impact of constructing and operating power generation plants at the state level. The JEDI model also uses an input-output methodology and was built utilizing economic data from IMPLAN. The JEDI model allows estimating of the economic impact of power generation investment in a state including local labor, services, materials, other components, fuel, and other inputs. The model also allows adjusting the portion of project investment that occurs locally.

5.1.2.2 Modeling Assumptions

As discussed above, the JEDI and IMPLAN estimates are sensitive to the set of assumptions utilized in the model, particularly the portion of project investment that occurs locally (local share). Through local share percentages, the model allows accounting for the leakage of economic activity outside the state's border. Table 5.1-1 presents the local shares for the construction phase that were used to estimate the economic impact of CREC on Rhode Island only. These parameters are consistent with those utilized in other similar studies and were adjusted to match Rhode Island's specific conditions. For instance, 100 percent of the spending with turbines (power generation) is paid to vendors outside Rhode Island. On the other hand, the model assumes that 87% of the construction labor required to construct the facility will be sourced from within Rhode Island.

Table 5.1-1
Local Share - Construction Phase

Item	Local Share
Facility and Equipment	
Power Generation	0%
General facilities	75%
Plant Equipment	5%
Labor and Management	
Construction Labor	87%
Project Management (construction and owner's)	16%
Others	
Engineering/Design	17%
Construction insurance	0%
Land	100%
Permitting Fees	100%
Grid intertie	25%
Spare Parts	5%
Sales Tax (Materials & Equipment Purchases)	100%

Table 5.1-2 provides the local shares utilized to calculate the economic impact of the ongoing operation of the CREC. It is worth noting that 100% of the spending on natural gas fuel (the commodity itself) will be paid to vendors outside Rhode Island. However, it also worth noting that 100% of the labor and 85% of the services, two major sources of ongoing spending and investment for a generation facility, are assumed to be sourced from State of Rhode Island business.

Table 5.1-2

Local Share- Operations and Maintenance Phase

Item	Local Share
Fixed Costs	
Labor	100%
Materials	25%
Services	85%
Variable Costs	
Water	100%
Catalysts & chemicals	85%
Fuel Cost	0%

The economic impact analysis also incorporates power market cost savings to Rhode Island ratepayers. The addition of new efficient generation capacity in Rhode Island will result in lower capacity and power prices for Rhode Island ratepayers in the near term, thereby driving significant savings to Rhode Island ratepayers during the plant's early years. These power market cost savings were determined by comparing Rhode Island's portion of energy and capacity market costs under modeling scenarios completed 1) with CREC at 1,000 MW-net, and 2) without CREC.

5.1.3 Economic Development Impacts

The construction, ongoing operation, and near-term ratepayer savings resulting from the Project will create jobs and drive significant economic development, both in Rhode Island and throughout the Northeast region.

The estimates in this section include the direct, indirect, and induced impacts of Project construction, ongoing operation, and ratepayer bill savings on Rhode Island's economy.

5.1.3.1 Economic Impacts – Rhode Island Only

To evaluate the economic impacts of CREC within Rhode Island, input-output analysis was completed according to the local share percentages introduced in Section 5.1.2.1.

Table 5.1-3 reports the annual job creation, earnings, and overall economic impact of CREC on the state of Rhode Island. It is important to note that the most significant economic impacts will be realized in the early years of the Project: the construction of CREC will bring significant investment and construction activity to Rhode Island from 2016 to 2019, and the first four years of operation will produce substantial energy and capacity cost savings to customers.

Table 5.1-3

Economic Development - Results Summary

Rhode Island Only, 2016-2034

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Employment Impact (FTEs per year)																			
Construction Period	47	718	930	250	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Facility Operations	0	0	0	123	216	220	225	230	235	240	246	251	257	262	268	274	280	286	292
Cost Savings to Customer	0	0	0	498	733	419	159	0	0	0	0	0	0	0	0	0	0	0	0
Total Employment Impact	**47**	**718**	**930**	**871**	**949**	**639**	**384**	**230**	**235**	**240**	**246**	**251**	**257**	**262**	**268**	**274**	**280**	**286**	**292**
Earnings Impact ($ - millions)																			
Construction Period	5.9	90.7	117.4	31.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Facility Operations	0.0	0.0	0.0	8.3	14.5	14.8	15.1	15.5	15.8	16.2	16.5	16.9	17.3	17.6	18.0	18.4	18.8	19.2	19.7
Cost Savings to Customer	0.0	0.0	0.0	26.3	39.5	23.5	9.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Earnings Impact	**5.9**	**90.7**	**117.4**	**66.2**	**54.0**	**38.3**	**24.1**	**15.5**	**15.8**	**16.2**	**16.5**	**16.9**	**17.3**	**17.6**	**18.0**	**18.4**	**18.8**	**19.2**	**19.7**
Economic Output ($ - millions)																			
Construction Period	8.9	137.1	177.4	47.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Facility Operations	0.0	0.0	0.0	19.9	34.8	35.6	36.3	37.1	38.0	38.8	39.6	40.5	41.4	42.3	43.3	44.2	45.2	46.2	47.2
Cost Savings to Customer	0.0	0.0	0.0	75.3	113.2	66.1	25.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Economic Output	**8.9**	**137.1**	**177.4**	**142.9**	**148.0**	**101.6**	**62.0**	**37.1**	**38.0**	**38.8**	**39.6**	**40.5**	**41.4**	**42.3**	**43.3**	**44.2**	**45.2**	**46.2**	**47.2**

In summary, the job creation, earnings, and overall economic impact of the Project on the state of Rhode Island are projected as follows:

- **Rhode Island Jobs** – From 2017-2021, which includes the most intense two years of construction and the first years of operation, CREC will support the creation of more than 820 full-time jobs per year. CREC will create an average of more than 400 full-time jobs per year from 2016-2034 in Rhode Island.
- **Rhode Island Earnings** – From 2017-2021, CREC will support the creation of approximately $370 million in earnings to Rhode Island workers, or more than $70 million per year. Earnings to Rhode Island employees as a result of CREC will total more than $600 million from 2016-2034.
- **Rhode Island Economic Output** – From 2017-2021, the total economic impact on Rhode Island is projected to be more than $700 million, or approximately $140 million per year. The overall impact of CREC on the Rhode Island economy will total almost $1.3 billion from 2016-2034, or an average of nearly $70 million annually.

Figure 5.1-1 provides a breakdown of the direct impacts versus the indirect and induced impacts of CREC construction and ongoing operations.

The direct economic impacts themselves will be significant, realized in the form of jobs, income, output, and benefits created directly by the construction and ongoing operations of CREC. In addition, CREC will generate significant economic activity in Rhode Island through input-output linkages among firms and households who are affected by its construction and operations. From 2016-2034, the indirect and induced economic impact of CREC on the Rhode Island economy will total $943 million, approximately 74% of the total output creation.

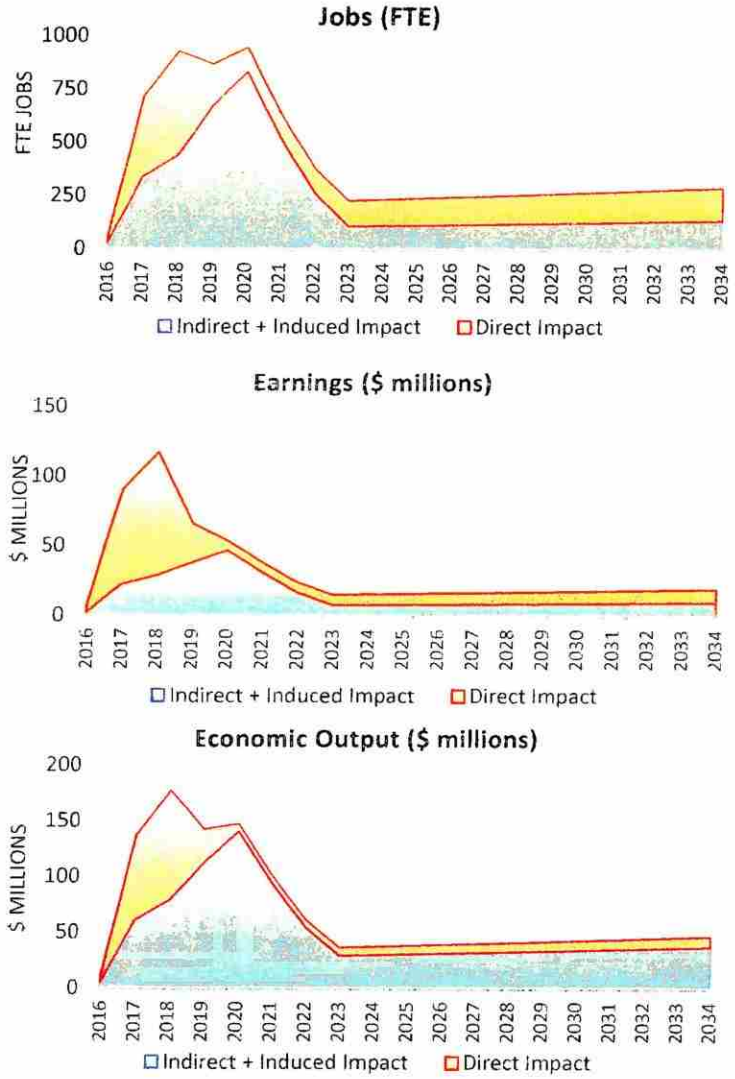

Figure 5.1-1
Direct vs Indirect/Induced Economic Impacts
Rhode Island Only

Similarly, approximately 50% of the $600 million in earnings that CREC will generate in the state from 2016 to 2024 will be indirect and induced earnings, and the jobs chart demonstrates that just under 60 percent of the jobs supported by CREC will be induced and indirect jobs. Overall, the impact estimates suggest that CREC operation and demand for local services and materials will have a significant multiplier effect on the state economy. This multiplier effect will be particularly strong for output creation.

5.1.3.2 Economic Impacts - Rhode Island and Surrounding Region

Significant economic impacts will accrue outside of Rhode Island as well. Project needs that cannot be met within Rhode Island – most notably generation equipment that is not currently manufactured within the state – will drive job creation and economic development in surrounding states. To evaluate

the economic impacts of CREC on Rhode Island and the surrounding region, input-output analysis was completed with all local share percentages introduced in Section 5.1.2.1 set to 100% except for fuel, which was kept at 0%. In other words, this scenario is designed to evaluate the approximate the economic impact of the construction and ongoing operation of CREC on Rhode Island and the surrounding region, but excludes the U.S. impact associated with ongoing natural gas procurement.

Table 5.1-4 presents the impact estimates of the plant on the economy as a whole.

Table 5.1-4

Economic Development Results Summary

Rhode Island and Surrounding Region, 2016-2034

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Employment Impact (FTEs per year)																			
Construction Period	147	2256	2921	786	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Facility Operations	0	0	0	258	453	463	473	483	494	505	516	527	539	551	563	575	588	601	614
Cost Savings to Customer	0	0	0	498	733	419	159	0	0	0	0	0	0	0	0	0	0	0	0
Total Employment Impact	**147**	**2256**	**2921**	**1542**	**1186**	**881**	**632**	**483**	**494**	**505**	**516**	**527**	**539**	**551**	**563**	**575**	**588**	**601**	**614**
Earnings Impact ($ - millions)																			
Construction Period	32.7	501.0	648.6	174.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Facility Operations	0.0	0.0	0.0	16.6	29.2	29.8	30.5	31.1	31.8	32.5	33.2	34.0	34.7	35.5	36.2	37.0	37.9	38.7	39.5
Cost Savings to Customer	0.0	0.0	0.0	26.3	39.5	23.5	9.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Earnings Impact	**32.7**	**501.0**	**648.6**	**217.4**	**68.7**	**53.3**	**39.4**	**31.1**	**31.8**	**32.5**	**33.2**	**34.0**	**34.7**	**35.5**	**36.2**	**37.0**	**37.9**	**38.7**	**39.5**
Economic Output ($ - millions)																			
Construction Period	33.6	515.2	667.0	179.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Facility Operations	0.0	0.0	0.0	69.8	122.3	125.0	127.7	130.5	133.4	136.3	139.3	142.4	145.5	148.7	152.0	155.4	158.8	162.3	165.8
Cost Savings to Customer	0.0	0.0	0.0	75.3	113.2	66.1	25.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Economic Output	**33.6**	**515.2**	**667.0**	**324.5**	**235.4**	**191.0**	**153.4**	**130.5**	**133.4**	**136.3**	**139.3**	**142.4**	**145.5**	**148.7**	**152.0**	**155.4**	**158.8**	**162.3**	**165.8**

Excluding the significant U.S. jobs impact associated with ongoing natural gas procurement, the economic impact of the plant on the economy as a whole (this time not limited to Rhode Island) is projected as follows:

- **Jobs** - The Project will support an average of approximately 850 full-time jobs per year from 2016-2034, with an average of approximately 1,750 full-time jobs created annually from 2017-2021, the most intense two years of construction and the first years of operation.
- **Earnings** - The Project will create nearly $2 billion in total earnings from 2016-2034.
- **Economic Output** -The Project will generate approximately $3.9 billion in total economic output from 2016-2034.

Figure 5.1-2 provides a breakdown of the direct impacts versus the indirect and induced impacts of CREC construction and ongoing operations. The direct impacts are similar in magnitude to those in the Rhode Island only analysis because most direct economic effects from the facility are realized within the state, but the total output is approximately three times as large and the indirect and induced impacts account for a much larger percentage of the economic impacts in this case.

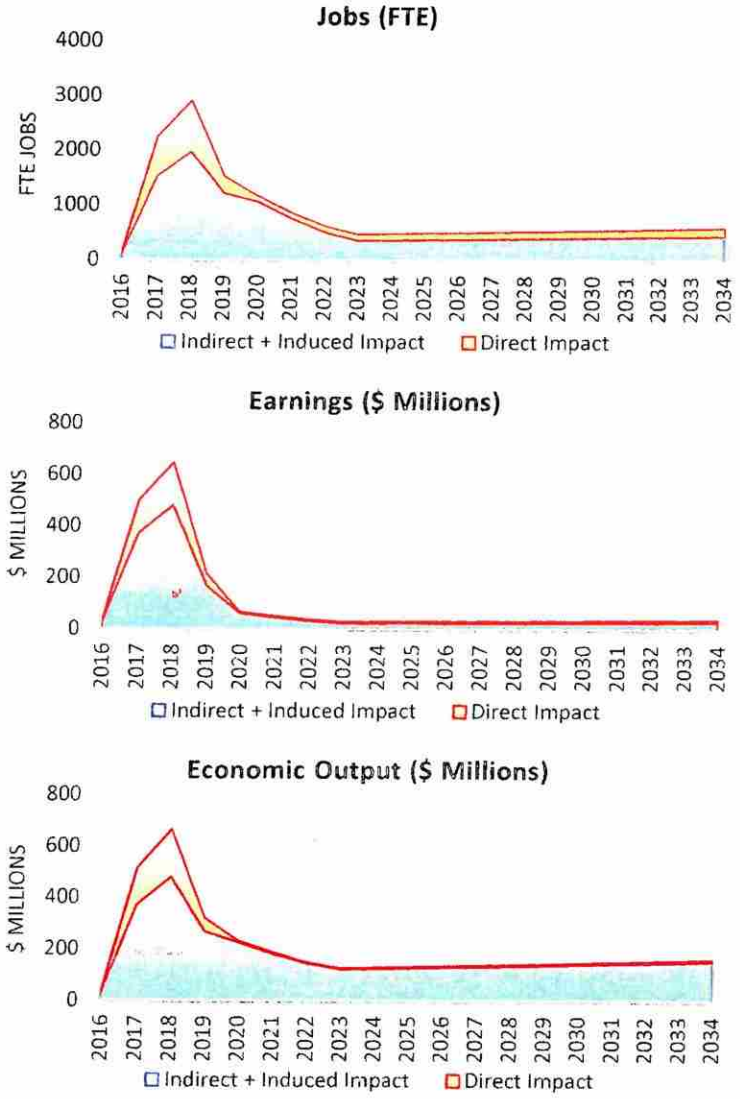

Figure 5.1-2
Direct vs Indirect/Induced Economic Impacts
Rhode Island and Surrounding Region

5.2 Regional Environmental Benefits

In addition to the economic benefits, the addition of the Project will reduce ISO-NE/NYISO Footprint CO_2, NO_x and SO_2 emissions by one (1) to four (4) percent per annum. See Table 5.2-1, which presents the results of the Aurora modeling analysis further described in section 7.0. These results include the recently announced retirement of Entergy's Pilgrim Nuclear Station

Table 5.2-1

Project Impact on Total Emissions Reductions on ISO-NE/NYISO Footprint

% Change

	2019	2020	2021	2022	2023	2024	2025
CO_2 Emission Change	-1%	-1%	-1%	-1%	-1%	-1%	-1%
NO_x Emission Change	-2%	-3%	-3%	-2%	-3%	-2%	-3%
SO_2 Emission Change	-3%	-4%	-4%	-3%	-3%	-2%	-3%

The net system-wide decrease is a result of CREC being a highly efficient natural gas-fired combined cycle power plant. CREC requires less fuel per MWh generated than its gas-fired peers, resulting in economic and emissions advantages relative to existing gas-fired generators. As such, CREC will displace less efficient, higher cost and potentially higher emitting resources that are currently dispatched on the power system. As a participant in the Regional Greenhouse Gas Initiative ("RGGI"), all thermal generators greater than 25 MW located within Rhode Island are subject to RGGI program CO_2 emissions caps. As such, the addition of the Facility will not impact the overall emissions reduction goals of RGGI given its emissions are also accounted for under the RGGI cap. Moreover, given the likelihood that the addition of the Facility will actually lead to an overall decrease in regional CO_2 emissions given the high efficiency of the unit (see previous section), it may lead to an overall less costly compliance trajectory for the region under the RGGI program.

In addition, as a new unit, the Facility will not be subject to the Environmental Protection Agency's ("EPA") recently finalized Clean Power Plan ("CPP"), which addresses CO_2 emissions from existing thermal resources. As such, the addition of the Facility will not impact the state of Rhode Island's overall ability to meet the CPP targets and, in some instances, could assist the state in meeting targets depending on the ultimate compliance pathways to be included in Rhode Island's yet-to-be developed and filed State Implementation Plan ("SIP").[1]

[1] Current regulations contemplate a final version or draft of the SIP to be submitted no later than September 2016.

TAB 7

7.0 ASSESSMENT OF NEED

7.1 Standards for Determining Need for the Proposed Facility

Load-serving entities ("LSE") located within the state of Rhode Island are members of ISO-NE, an independent, non-profit Regional Transmission Organization ("RTO") serving Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont. Among other items, ISO-NE is tasked with system planning, operating the power system, and administering the region's Federal Energy Regulatory Commission ("FERC") approved wholesale energy, ancillary and capacity markets for members operating within these states.

In 1997, ISO-NE was created by NEPOOL[4] market participants to operate the regional power system, implement wholesale markets, and ensure open access to transmission. In 2005, FERC Order 2000 designated ISO-NE as an RTO. As an RTO, ISO-NE assumed the additional responsibility for system planning. In order to facilitate this mission, system planning for capacity and reliability within ISO-NE member states is accomplished through ISO-NE's Forward Capacity Market ("FCM") capacity procurement mechanism, approved by FERC in 2006.

As members of ISO-NE, Rhode Island LSEs rely upon the ISO-NE FCM capacity procurement mechanism developed by ISO-NE stakeholders and approved by FERC, in which ISO-NE seeks to procure sufficient capacity, on a both a system-wide and localized basis, three-years in advance of a Delivery Year[5] ("DY") in order to meet projected peak demand *plus* minimum target reserve margins.

7.1.1 Governing Rhode Island Statutes, Policy and Regulation

In 1996, in accordance with FERC Orders 888 and 889, state regulators and LSEs throughout the New England region began the process of electricity market deregulation. The State of Rhode Island Public Utilities Commission ("PUC") began formal participation in the region's process of deregulation with the enactment of the Rhode Island Restructuring Act of 1996, and facilitated more broadly by the NEPOOL organization.

In December 1997, the Rhode Island PUC issued an order approving retail choice for all Rhode Island consumers. Retail choice allows Rhode Island ratepayers the flexibility to select a competitive retailer to supply their electricity, while relying on the local electric utility for distribution service; this order fundamentally altered the state's electric market structure by relying on regional NEPOOL/ISO-NE mechanisms to incent the economic development of new (and economic retention of) capacity to maintain system reliability. Currently, there are three distribution companies operating in Rhode Island. National Grid manages the distribution system for approximately 99 percent of Rhode Island. Block Island Power Company and the Pascoag Utility District serve the remaining areas on Block Island and in western Burrillville, respectively.

7.1.2 ISO-NE FCM Overview and Objectives

ISO-NE's FCM capacity procurement mechanism is utilized by ISO-NE market participants as a means to ensure that the ISO-NE power system has sufficient resources to reliably meet the future demand for electricity. Under the FCM, Forward Capacity Auctions ("FCA") are utilized as a market-based approach to determine both system-wide and localized needs for both existing and new generation capacity through a competitive auction process designed to select the portfolio of existing and new resources needed for system-wide and local reliability with the greatest social surplus.[6] In other words, resources that clear an FCA are, by definition, the resources that maximize social surplus in order to meet both system-wide and local reliability needs.

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[4] New England Power Pool, the historical central authority for region-wide resource planning and dispatch in the New England region.
[5] Within ISO-NE, a Delivery Year runs from June 1 through May 31 of the following year.
[6] Social surplus, sometimes called social welfare, is the sum of consumer and supplier surplus, which is maximized when demand equals supply.

FCAs are conducted three-years prior to the capacity commitment period (i.e., DY) for which it is being held. In addition to the FCA, annual, seasonal, and monthly reconfiguration auctions are held in order to adjust the amount of capacity needed.[7] The FCA is a descending clock auction whereby the auction starting price is reduced in each round until the amount of remaining capacity is equal to the value that ISO-NE places on additional excess capacity, based on its demand curve parameters. Capacity resources participating in the FCA do not submit sell offers; existing capacity resources that wish to withdraw from the auction must submit a de-list bid, which is subject to a reliability review.[8]

The capacity that is required to meet ISO-NE's future system-wide demand is called the Installed Capacity Requirement ("ICR"). The ICR is the minimum amount of capacity required for ISO-NE to meet its resource adequacy-planning criterion. Additionally, the FCM takes into account locational capacity needs to ensure that regional zones have sufficient capacity to maintain reliability when transmission constraints prevent the delivery of electricity to any particular capacity zone. Capacity requirements vary from year to year, with the specific system-wide and local capacity requirements for the 2019/2020 capacity commitment period to be filed with FERC in late 2015.

For each FCA, capacity resources incur a capacity obligation of one year, which requires the capacity resource to bid into the day-ahead energy market. In return, cleared resources are financially compensated to do so at the applicable clearing price for that FCA (and are financially penalized if the resource does not deliver on the assigned capacity obligation). New resources can opt to convert the one-year obligation into a multi-year award, up to seven years.

7.2 Need for the Proposed Facility

ISO-NE's next FCA is for the 2019/2020 capacity commitment period ("FCA 10"), which will be held in February 2016. This auction will ultimately determine the capacity that is needed in the market for reliability in ISO-NE during the 2019/2020 DY, and the CREC intends to participate in this auction. As a planned participant in FCA 10, the system-wide and local need for Clear River's capacity will be determined via the FCM capacity auction mechanism. In other words, if the facility clears FCA 10, then ISO-NE will have determined CRECto be a needed resource that maximizes social surplus to meet the overall system-wide and local reliability needs of ISO-NE.

Given FCA 10 will not occur until February 2016, PA Consulting Group, Inc. ("PA") prepared an analysis of Clear River's impacts within the ISO-NE wholesale market, including (1) economic projections related to the outcome of FCA 10; (2) impacts on Rhode Island electric reliability; (3) impacts on Rhode Island ratepayer costs; and (4) impacts on Rhode Island emissions reduction objectives.

7.2.1 Analysis of Need - Economic

PA has a robust, well-developed, and industry-tested fundamental power market modeling process, including its proprietary stochastic dispatch optimization, capacity compensation, environmental, renewable, and valuation models along with the use of production cost, transmission, and natural gas models that are operated by PA's subject matter experts and populated with PA proprietary data. Since 2011, PA has utilized this power market modeling process to support the development, acquisition,

[7] For the 2010/11 through the 2014/15 Delivery Years, two annual reconfiguration auctions were held, 14 months prior and 2 months prior to the start of the Delivery Year. For the 2015/16 Delivery Year and beyond, 3 annual reconfiguration auctions are to be held, 26 months, 14 months and 2 months prior the start of the Delivery Year. Seasonal reconfiguration auctions are held prior to June, for the summer seasonal reconfiguration auction (June-September), and prior to October, for the winter seasonal reconfiguration auction (October-May).

[8] A de-list bid allows existing capacity to exit the auction if the price falls below a pre-defined level. Two common types of de-list bids are static and dynamic bids. A static de-list bid is submitted prior to the auction; a dynamic de-list bid is submitted during the auction. All de-list bids are subject to a reliability review by ISO-NE prior to being accepted. For the 2016/17 and prior FCAs, de-list bids below 0.80 x CONE were subject to ISO review. For the 2017/18 FCA, static de-list bids below the associated offer review trigger price for a specific resource type were subject to ISO-NE review. Dynamic de-list bids can only be entered after clearing prices have dropped below $1.00/kW-mo and the bid(s) must be below $1.00/kW-mo.

divestment, and financing of over 200,000 MW of power generating assets in North America, including 15,000 MW in the ISO-NE market.

PA's modeling process incorporates a suite of tools, including (1) AURORAxmp[9] for its production cost modeling in order to project wholesale energy market prices; (2) PA's proprietary environmental optimization model that integrates the natural gas-power-coal sector, as well as the coal generator capital expenditure versus coal selection and resulting emissions prices, paradigms; (3) PA's proprietary stochastic model to assess specific generator operations and economics relative to the electric system; and (4) PA's proprietary FCM Simulation Model. PA's fundamental power market projections were generated using the Aurora^{XMP} model. Aurora^{XMP} is a power market simulation tool based on an hourly dispatch engine that simulates the dispatch of power plants in a chronological, multi-zone, transmission-constrained system and is widely used for electric-market price forecasting, resource valuation and market risk analysis. For emissions analyses, emissions are aggregated on an annual basis in Aurora^{XMP} from individual hourly plant-level dispatch results, with calculated emissions for each resource determined as a function of the plant's simulated dispatch level, assumed emissions rate, and resource heat rate.

7.2.1.1 PA's FCM Simulation Methodology and Results

Utilizing PA's proprietary FCM Simulation Model, within the context of PA's broader wholesale energy market analysis of the ISO-NE region utilizing the aforementioned modeling architecture, PA's FCA capacity price forecast was developed based on its forecasts of (1) existing and new capacity (i.e., total capacity); and (2) PA's projected FCA 10 demand curve parameters as of June 2015. The demand curve parameters effectively determine the capacity price based on a given amount of capacity. All else equal, the higher the total capacity the lower the capacity price. This mechanism is illustrated in Figure 7.2-1 below.

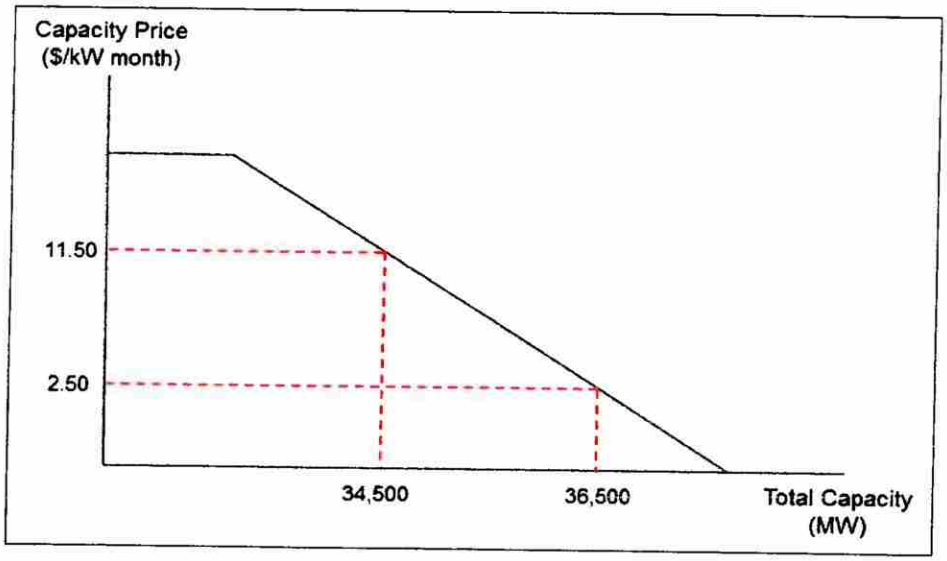

Figure 7.2-1
FCA Capacity Price Derivation - Illustrative

[9] EPIS, Inc.

For FCA 10, PA projected existing capacity based on capacity from FCA 9, and the following expected changes for FCA 10:

1. In FCA 10, ISO-NE is planning to combine the Southeastern Massachusetts/Rhode Island ("SEMA/RI") transmission constrained capacity zone with the Northeastern Massachusetts/Boston ("NEMA/Boston") capacity zone to form a new, larger transmission-constrained capacity zone – called the Southeastern New England ("SENE") zone;
2. In FCA 9, the SEMA/RI capacity zone had less capacity than was needed for reliability (the zone had a deficit of approximately 250 MW), while NEMA/Boston had more capacity than was needed for reliability; and

CRECis projected to participate in FCA 10, bidding approximately 1,000 MW into the new SENE zone.[10]

This results in a projection of total capacity for FCA 10 of 35,841 MW. (In comparison, the total capacity in FCA 9 was 34,694 MW.) When the total capacity of 35,841 MW was overlaid against PA's forecast of the FCA 10 demand curve, the resulting capacity price was lower than the clearing prices that resulted from the last capacity auction. The resulting price represents PA's projection of FCA 10 capacity prices for all capacity resources in New England with CREC clearing the auction mechanism.

With the announced retirement of the Pilgrim Nuclear Station in Plymouth MA, which is in the SENE zone and the loss of its 690 MW, there will be capacity needs in this zone to make up that loss. In evaluating the impact of this loss on the FCA 10 demand curve, the resulting capacity price is expected to be increased over prior projections with Pilgrim still in service.

7.2.1.2 Conclusions

Based on the aforementioned analysis, and combined with (1) PA's broader independent economic analysis of the ISO-NE wholesale energy, ancillary and capacity markets; and (2) underlying CREC development costs, PA projects that CREC would clear FCA 10 at a projected clearing below previous clearing prices for the SEMA/RI zone. As previously outlined, by definition, if the facility clears FCA 10, then ISO-NE (and, by proxy, Rhode Island LSEs whom are participants in ISO-NE) will have determined CREC to be a needed resource that maximizes social surplus to meet the overall system-wide and local reliability needs of ISO-NE.

7.2.2 Analysis of Need - Reliability

As discussed in the previous sections, (1) a resource that clears the FCA has been determined by ISO-NE to be a needed resource that will maximize social surplus to meet the overall system-wide and local reliability needs of ISO-NE; and (2) the state of Rhode Island is located within a transmission constrained zone (SENE) for FCA 10, indicating the need for locally sited resources (existing or new) to address current and on-going transmission import constraints – without which reliability within the SENE capacity zone (and, by proxy, the state of Rhode Island) may be comprised under certain scenarios.

By definition, the siting of a new facility, such as Clear River, within the SENE capacity zone will enhance, all else equal, reliability within the SENE capacity zone (and, as such, the reliability of electric service for Rhode Island ratepayers). In addition, even under a scenario in which the SENE capacity zone has adequate capacity to meet local reliability needs[11], the addition of a capacity resource within the SENE zone will still promote the overall reliability of the broader ISO-NE footprint with which the SENE zone

[10] In addition to Clear River's capacity, PA assumes approximately 175 MW of incremental renewable and demand response capacity.

[11] It should be noted that local capacity requirements within transmission-constrained zones can change year-to-year, based on capacity retirements, capacity additions, load growth, and transmission topology changes. In other words, a single FCA result is not necessarily indicative of whether future reliability needs will be met within the capacity zone – a scenario that the FCM construct is designed to account for.

electrically interconnects (and upon which it relies for a portion of its reliability needs as an interconnected system). In other words, regardless of whether or not the SENE capacity zone "breaks out" from the broader Rest of Pool capacity zone, the result of CREC clearing FCA 10 indicates that it will maximize social surplus and promote reliability in the region.[12]

7.2.2.1 Reliability of CREC Natural Gas Supply

In addition to the aforementioned electric reliability narrative, it is important to point out that, in addition to the physical location of the resource within the SENE capacity zone, the CREC is projected to provide enhanced reliability to the SENE capacity zone (and, by proxy, Rhode Island ratepayers) through its planned used of firm natural gas transport for a portion of its natural gas needs. The election of this fuel transport service, from a reliability standpoint, should advantageously position the facility vis-à-vis other generators that rely on interruptible transport service and, to a lesser extent, those facilities that rely on fuel oil as a back-up fuel source during extreme events (e.g., the Polar Vortices of Winter 2013/2014).

7.2.3 Analysis of Need – Rhode Island Ratepayer Cost Impact

As part of its due diligence, PA analyzed the rate impacts of CREC to Rhode Island electricity customers and found that CREC would result in reduced energy and capacity costs to Rhode Island ratepayers. In order to perform the analysis, PA analyzed the rate impacts for Rhode Island customers under two scenarios, and then compared the two scenarios to determine the net impacts of CREC on Rhode Island ratepayers.

1. The first scenario projected total energy and capacity costs to Rhode Island without the addition of CREC to the ISO-NE market; and
2. The second scenario projected total energy and capacity costs to Rhode Island with the addition of Clear River.

Partially due to the participation of CREC in FCA 10, PA projects FCA 10 capacity prices for capacity resources in Rhode Island and across New England to be significantly lower than FCA 9 capacity prices – resulting in significantly lower capacity prices. For example, the FCA 10 capacity revenues projected to be earned by CREC (based on the expected capacity price) are approximately $130 million lower than they would be if CREC had received Exelon Medway's FCA 9 capacity price, and approximately $30 million lower than they would be if CREC had received Competitive Power Ventures ("CPV") Towantic's FCA 9 capacity price.

In the first four years of operation (2019-2022), market projections indicate that CREC would save Rhode Island ratepayers $284 million in capacity and energy costs, or more than $70 million annually. The additional CREC capacity is projected to result in capacity cost savings of nearly $220 million in this timeframe, with energy cost savings of approximately $65 million as CREC displaces less efficient generation resources. Thereafter, Rhode Island ratepayers would continue to realize approximately $23 million in energy cost savings per year, with capacity cost impacts (which could offset some of, or be accretive to, these savings) determined by the types of new development capacity that enter the ISO-NE market to maintain reliability after Clear River's market entry.

[12] We utilize the term "breaks out" to indicate that the SENE capacity zone clears at a higher capacity price than resources located outside of the SENE zone – indicating an enhanced need for (or current deficit of) supply within the SENE capacity zone vis-à-vis the rest of the ISO-NE footprint.

7.2.4 Analysis of Need – Impact on Rhode Island Emissions Goals

In addition to the system need and the economic impact of CREC to Rhode Island ratepayers, PA also assessed the emissions impact of CREC on the ISO-NE and New York ISO ("NYISO") footprints13 and found that the addition of CREC will reduce CO_2, NO_x and SO_2 emissions every year. See Table 7.2-1

Table 7.2-1

Impact of CREC on Total Emissions Reductions on ISO-NE/NYISO Footprint

(CO_2 in 000's of Short Tons; NO_x and SO_2 in Short Tons)

	2019	2020	2021	2022	2023	2024	2025
CO_2 Emission Change	-783	-1,233	-1,122	-1,011	-998	-985	-1,002
NO_x Emission Change	-1,591	-3,169	-2,668	-2,168	-1,939	-2,047	-2,096
SO_2 Emission Change	-1,960	-3,985	-3,325	-2,664	-2,539	-2,417	-2,442

The net system-wide decrease is a result of CREC being a highly efficient natural gas-fired combined cycle power plant. CREC requires less fuel per MWh generated than its gas-fired peers, resulting in economic and emissions advantages relative to existing gas-fired generators. As such, CREC will displace less efficient (and less environmentally-friendly) resources that are currently dispatched on the power system.

CREC will not materially impact the ability of New England (or Rhode Island) to meet CO_2 emissions reduction targets.

As a participant in the Regional Greenhouse Gas Initiative ("RGGI"), all thermal generators greater than 25 MW located within Rhode Island are subject to RGGI program CO_2 emissions caps. As such, the addition of CREC will not impact the overall emissions reduction goals of RGGI given its emissions are also accounted for under the RGGI cap. Moreover, given the likelihood that the addition of CREC will actually lead to an overall decrease in regional CO_2 emissions given the high efficiency of the unit (see previous section), it may lead to an overall less costly compliance trajectory for the region under the RGGI program.

In addition, as a new unit, CREC will not be subject to the Environmental Protection Agency's ("EPA") recently finalized Clean Power Plan ("CPP"), which addresses CO_2 emissions from existing thermal resources. As such, the addition of the facility will not impact the state of Rhode Island's overall ability to meet the CPP targets and, in some instances, could assist the state in meeting targets depending on the ultimate compliance pathways to be included in Rhode Island's yet-to-be developed and filed State Implementation Plan ("SIP") or the EPA's under-development Federal Implementation Plan ("FIP").

7.3 Need Analysis Conclusion

The analysis conducted in this section has demonstrated that the FCM is the appropriate and core mechanism to determine system need for member states within ISO-NE. While FCA 10 will ultimately determine if CREC is needed, PA's analysis suggests that the facility will clear the auction. As previously outlined, by definition, if the facility clears FCA 10, then ISO-NE (and, by proxy, Rhode Island LSEs whom are participants in ISO-NE) will have determined CREC to be a needed resource that maximizes social surplus to meet the overall system-wide and local reliability needs of ISO-NE. In addition, and in concert with this capacity market construct, PA's analysis suggests that Clear River's physical location within the SENE capacity zone and its proposed use of

[13] PA analyzed the combination of the ISO-NE and NYISO footprints given their high degree of interconnectivity and seams agreements that help to facilitate participation of a resource in either market's wholesale and capacity markets; in addition, states in both markets are subject to regional greenhouse gas reduction programs.

firm natural gas transport contracts will further reliability goals of the transmission-constrained SENE zone (of which Rhode Island is a part).

Additionally, it has been demonstrated that CREC will have a positive economic and environmental impact on Rhode Island customers. PA's analysis indicates that with the addition of Clear River, Rhode Island ratepayers will save $284 million in capacity and energy costs within the first four years of Clear River's commercial operations. Moreover, the analysis indicates CREC will have a net positive emissions impact in the region by displacing less efficient forms of generation that have higher emissions per unit of energy produced, and will have no detrimental impact on Rhode Island or the broader New England region in meeting RGGI or CPP emissions goals.

TAB 8

8.0 CONFORMANCE WITH RHODE ISLAND ENERGY POLICY

The Energy Policy Act of 1992 (Act) granted states the power to create competitive markets for electricity generation changing the electricity industry from regulated local monopolies, providing all electric services (generation, transmission and distribution), into a network of independent competitive companies providing electricity generation with regulated utilities providing transmission and local distribution of electricity. As a result, in 1996 Rhode Island became the first state in the nation to deregulate its electric industry.

In 2002 the State of Rhode Island adopted the Rhode Island Energy Plan 2002 to help Rhode Island determine how best to meet its future energy production and consumption needs. The objective was a reliable, low-cost and environmentally benign supply of energy, to support economic growth and safeguard consumers from supply disruptions. The planning horizon for Energy Plan 2002 extended to the year 2020.

In June 2015 Rhode Island issued a Preliminary Draft of "Energy 2035", which when finalized and adopted by the State will replace Energy Plan 2002 with a new Energy Plan with a planning horizon out to 2035. Energy 2035 plan is the product of a collaborative effort over a number of years by numerous private and public stakeholders. Energy 2035, once finalized and adopted by the State, is intended to guide the activities of the Rhode Island Office of Energy Resources and the Division of Planning by setting goals and policies to improve energy security, cost-effectiveness, and sustainability in all sectors of energy production and consumption of the State of Rhode Island.

Although Energy 2035 has not as yet been adopted by the State, Invenergy has reviewed the preliminary draft of Energy 2035 and believes the Project supports many of the goals and policies of Energy 2035 in its current form.

The State of Rhode Island's electric generation portfolio has scarcely changed over the past decade while energy use and specifically the use of electricity has significantly increased over the same period. A reliable electricity supply is a necessity to both Rhode Island and regional economies as recognized by Energy 2035. New England must compete with other regions of the U.S. to attract businesses and investment opportunities and a reliable electric supply is critical to sustain competitiveness with other regions. The Project will provide a new modern energy efficient electricity generation resource to the State of Rhode Island and the region to help ensure a reliable energy supply supporting local and regional economies and help maintain the overall competitiveness of New England.

Rhode Island has few indigenous energy resources and must import most of the fuels from which its electricity is generated. Although renewables have experienced significant growth in the last few years and is a promising resource for the future, renewables are not growing at a sufficient pace to fully replace the rate of retirements of older electric generation facilities. Many of these older electric generation facilities have lower energy efficiencies; do not employ modern emission controls and/or rely solely on more polluting fuels like oil and coal.

Until the total generation provided by renewables in New England (primarily wind and solar) grows to a sufficient level to allow consideration of fully relying on renewable energy resources in the future, another energy resource, such as natural gas, must be used to provide the bulk of the energy supply and provide a backup energy source to balance the intermittency of renewable energy resources. Over time the growth of

renewable energy resources, supplemented by energy storage, will expand to a level that will reduce dependency on natural gas fueled electric generation but in the interim Rhode Island must rely on a mix of generation technologies and energy resources to meet the needs of the region.

Energy 2035 has many goals and policies that will set the energy programs in Rhode Island for the near future. Energy 2035 emphasizes as key to the overall program initiatives for increasing energy efficiency, need for integration of renewables, need to achieve reductions in greenhouse gases and need to modernize the electric grid to support transfers of energy within the region and ensure the overall reliability of the energy supply within New England.

The Project will be the most energy efficient electric generating facility in New England and has been sited to take advantage of other major infrastructure investments being made in the natural gas supply and regional electric transmission system.

Major investments to the natural gas infrastructure are currently being made by the natural gas pipeline suppliers to increase the overall reliability of natural gas supply to New England and to alleviate winter shortages of this important fuel. Commensurate with these investments are major investments being made by the electric transmission utilities in the region to increase the overall reliability of the transmission system and to ensure flow of electricity within the region to the benefit of both existing and future electric generation. The site of the Project takes advantage of these major investments in natural gas supply and regional electric transmission infrastructure upgrades.

The Project will in its early years be a base loaded generating facility (operating near full capacity) because of its lower cost of generation owing to its high energy efficiency compared to other older generating facilities in the region. Older less efficient generating facilities in the region will be operated as intermittent generating units (operated less of the time) owing to their higher energy costs. As a result, the construction and operation of the Project will directly reduce the amount of greenhouse gases and other air pollutants generated in the region by displacing these older less efficient electric generating facilities. Rhode Island is a coastal state with a uniquely high percentage of coast line compared to any other costal state. As such, impacts of greenhouse gases on global warming are of significant interest to the State and is a major focus of Energy 2035.

In the future with increasing investments in renewable energy resources (on-shore and off-shore wind and PV solar) the percentage of time that natural gas electric generation facilities will operate will be reduced as a great percentage of the regions energy supply is met by the renewable energy resources. As a result natural gas generating facilities must be designed to provide the future flexibility needed to provide high energy efficiency, quick startup capabilities and have load following features to balance the intermittency and variability of the growing renewable energy resources of the region. The Project has been specifically designed to meet these future challenges featuring fast start capabilities while under full emission control allowing the Project to fully integrate with the needs of the region with increasing renewable investments in the future.

For the reasons outlined above the Project is believed to be fully in conformance with Rhode Island Energy Policy.

TAB 9

10.0 STUDY OF ALTERNATIVES

Invenergy conducted a detailed evaluation of the New England market to identify specific areas that may be in need for new generation, have available infrastructure that could support a new combined cycle plant and have sufficient land and proper zoning that would allow a combined cycle plant to be built.

As part of the Forward Capacity Market (FCM), ISO New England Inc. (ISO-NE) conducts a Forward Capacity Auction (FCA) three years in advance of each Capacity Commitment Period (CCP) to meet the region's resource adequacy needs. The latest FCA 9, conducted on February 2, 2015, resulted in capacity (megawatts) commitments of sufficient quantities to meet the Installed Capacity Requirement (ICR) for the 2018/19 CCP however, the SEMA/RI capacity zone had less capacity than was needed for reliability (the zone had a deficit of approximately 250 MW).

ISO-NE issued the report "ISO New England Installed Capacity Requirement, Local Sourcing Requirements and Capacity Requirement Values for the System-Wide Capacity Demand Curve for the 2018/19 Capacity Commitment Period", Feb. 2015, documenting the assumptions and simulation results of the 2018/19 CCP ICR, Local Sourcing Requirements (LSR) and Capacity Requirement Values for the System.

For the 2018/19 CCP, ISO-NE has identified three Load Zones that are import constrained and as a result, modeled as Capacity Zones in FCA9. These Capacity Zones are Connecticut, Northeast Massachusetts/Boston (NEMA/Boston) and the combined Load Zones of Southeastern Massachusetts and Rhode Island (SEMA/RI).

LSR for import-constrained Capacity Zones involves calculating the amount of resources located within the Capacity Zone that are required to meet needs. For instances where there is insufficient generation within a zone, Proxy units are required to meet the resource adequacy planning criterion specified by ISO NE. For the FCA 9 SEMA/RI LSR analysis, an 800 MW proxy unit was needed to bring the zone and the system into compliance with the system requirements. A similar report was issued by ISO NE in 2014 that contained similar results and it was this report that Invenergy used to identify specific geographic areas where locating a new facility would satisfy this need. The SEMA/RI area encompasses all of Rhode Island and the Southeastern portion of Massachusetts. Within this area there are few locations to site a new facility. Suitable locations must have access to a large natural gas pipeline (like Algonquin) access to high voltage transmission, preferably 230 kV and higher, be properly zoned, have suitable buffer to any nearby residential properties at a minimum. The Algonquin pipeline is only 8 miles long within the State of Rhode Island and the only industrial parcels that it crosses where a power plant would be permitted are the parcels owned by Algonquin Gas Transmission (AGT) and TransCanada's Ocean State power plant site. There are additional parcels within the town of Burrillville that are suitably zoned to allow a power plant, however these parcels are surrounded by residential parcels and were deemed much less ideal as a result.

AGT's total acreage is approximately 730 acres and includes not only the AGT pipeline but also a double circuit 345 kV transmission line making it an ideal location for a power plant as no additional Rights of Way are needed (beyond those the project will need from AGT). Invenergy and AGT evaluated locating the project within the 730 site at several locations and collectively determined the proposed location as being the best for the following reasons;

1. Parcel will have frontage on Wallum Lake road
2. There will not be a need to have a new access road that would cross over the pipe line
3. Suitable buffer to nearby residential properties and to the AGT compressor station

Based on the above Invenergy determined that the proposed location is the best location.

10.1 Power Generation Alternatives

The power generation production process alternatives considered included fossil fuels, renewable energy technologies (e.g., wind, solar, biomass, geothermal and hydropower), energy efficiency and conservation, and the no-action alternative.

An analysis of alternatives necessarily begins with a definition of the objective being considered. For purposes of discussing technology alternatives, the major considerations are the size of the energy need proposed to be met and the characteristics of operation, i.e., peaking, intermediate, or baseload. In this case, Invenergy has proposed a generating plant intended to meet the local and regional electric energy needs that are expected to reach over 6,000 MW in the regional grid into which the Project will be connected. This figure consider older fossil fuel plant retirements caused by increased environmental regulation and negative economics resulting from the surge in availability of low cost natural gas. In addition to the retirements, there is also a steady increase in energy demand to be considered.

Many of the older fossil fuel power plants mentioned above that have been announced or expected to be retired are fueled by coal and or oil. As such, they have traditionally been looked to for baseload power supply, i.e., constant operation throughout the year subject only to maintenance outages.

10.1.1 Fossil Fuel and Technology Alternatives

Fossil plants using coal or oil were removed from consideration because the costs to comply with the anticipated environmental regulations (on a $/kW basis) were much higher than a comparably sized natural gas plant. Further, even with the installation of control technologies on coal or oil plants, the resulting environmental impacts were still far greater than a comparably sized natural gas plant. Compared to fuel oil or coal, natural gas is a relatively clean and efficient fuel that can reduce relative impacts on air quality (e.g., reduce emissions of nitrogen oxides, sulfur dioxide, particulate matter and carbon dioxide) to generate the same amount of electricity. In addition, the characteristics of the technology that is used in these plants is such that they have long start times, relatively slow response times to changing power demand and as a result they are sometimes termed as being in-flexible and not able to compensate for the generation demand that a modern power supply network has when a large amount (greater than 10%) of renewable generation is present. the overall footprint of a comparably sized coal plant is significantly larger than that of a natural gas plant.

Invenergy also considered available natural gas power generation processes (e.g., reciprocating engines, boilers, combustion turbines), energy recovery cycles (e.g., simple-cycle, combined-cycle, combined heat and power), and cooling systems (e.g., evaporative, dry, and once-through cooling). Combustion turbines in combined-cycle operation were determined to be the most efficient and cost-effective for the proposed size. Combined heat and power systems were not considered due to the inability to find end users with sufficient load in the area selected for the Project.

Invenergy also considered impacts associated with use of fuel oil as a back-up fuel. Given the Project's location in the New England ISO market, and the fact that during critical winter periods there may be times when sufficient gas is not available due to the current limitations on available gas transportation (e.g. pipeline capacity). Therefore, it was determined that to meet ISO-NE reliability requirements, the Project would incorporate the use of fuel oil as a backup fuel.

10.1.2 Renewable Technology Alternatives

Wind Generation

Modern wind turbines represent potentially viable alternatives to large bulk power fossil power plants as well as small-scale distributed systems. The capacity for an individual wind turbine today ranges from 400 watts up to 3.6 MW. Although air emissions are essentially eliminated for wind facilities, wind turbines can have significant visual and noise impacts that generate strong opposition. Apart from the visual impact of

the structures themselves, rotating wind turbine blades interrupt the sunlight producing unavoidable flicker bright enough to pass through closed eyelids, and moving shadows cast by the blades on windows can affect illumination inside buildings. This effect, commonly known as shadow flicker, has been claimed to have the potential to induce photosensitive epilepsy seizures.

Wind turbines also cause bird mortality (especially for raptors) resulting from collision with rotating blades. The rotating blades also affect bats and the Indiana bat, a federally listed endangered species, habits almost all of Pennsylvania. Recent opposition to wind farms has led to shutdowns and curtailments of operation for fear that Indiana bats might be killed.

Wind generation facilities would require large land areas in order to generate 1,000 MW of electricity. Depending on the size of the wind turbines, wind generation "farms" require large tracts of land – approximately two to five acres of directly impacted area (turbine area, roads, substation, and transmission) and approximately 84 to 138 acres of indirectly impacted area (terrain and wind patterns greatly affect the spacing of the turbines so as to obtain optimal production; buffer areas are also required) to generate one MW. See National Renewable Energy Laboratory, Land-Use Requirements of Modern Wind Power Plants in the United States, Technical Report, NREL/TP-6A2-45834 (August 2009). This calculation results in as much as 120,000 acres required to generate 1,000 MW. See also California Energy Commission, Commission Decision, Russell City Energy Center (July 2002, P800-02-007) (wind farm would require 17 acres per MW; thus requiring 17,000 acres to generate 1,000 MW). These land requirements are significantly more than the amount of land used by the Invenergy CREC Project.

Offshore wind is in its infancy and the first phase of the Deepwater Wind project is sized at 35 MW and the second phase is planned to be 1,000 MW assuming it's proved economically viable. That stated, the wind available for land-based wind generating facilities in Rhode is not as good at the wind available off shore. One other item to consider is that the output of wind and other renewable resources is variable and not dispatchable on demand and can have rapid and sizeable swings in electricity output due to wind speed, time of day, cloud cover, haze, and temperature changes (which is why they are called variable or intermittent resources). The ISO-NE recognizes the variable nature of these resources and states in their 2015 Regional Electricity Outlook that" *Wind and solar resources will eventually help achieve federal and state environmental goals. Paradoxically, the operating characteristics of these renewable resources—which are different than traditional power plants—will increase reliance on fossil-fuel-fired natural gas generators.* This is because intermittent resources are not dispacthable on demand and, as such, have a limited ability to serve peak load and still need to have a dispatchable resource available to help match their output variations.

Finally, wind energy technologies cannot provide full-time availability due to the natural intermittent availability of wind. The inflexible and non-dispatchable nature of wind generation – its limited dependability – are defining differences between that electricity generating alternative and the Project.

With all the aforementioned characteristics and impacts, i.e., environmental trade-offs, wind energy generation is not a feasible alternative to the Project.

Solar Generation

Like wind farms, solar resources, both solar thermal and solar photovoltaic, would require large land areas in order to generate the approximate 1,000 MW of electricity proposed to be supplied by the Project.[14]

[14] Most solar thermal technologies collect solar radiation, then heat water to create steam to power a steam turbine generator. The primary systems that have been used in the United States capture and concentrate the solar radiation with a receiver. The three main receiver types are mirrors located around a central receiver (power tower), parabolic dishes and parabolic troughs. Another solar thermal technology collects the solar radiation in a salt pond and then uses the heat collected to generate steam and drive a steam turbine generator. Solar photovoltaic ("PV") technology uses photovoltaic "cells" to convert solar radiation directly to direct current electricity, which is then converted to alternating current. Solar thermal facilities are generally dispatchable while solar PV facilities are not.

Specifically, assuming location in an area receiving maximum consistent solar exposure (such as desert areas of the southwest), central receiver solar thermal projects require five or more acres per MW, so 1,000 MW would require approximately 5,000 acres of land under ideal "desert-like" conditions and much more land under "Rhode Islandia-like" conditions. See generally http://en.wikipedia.org/wiki/Solar_power_plants_in_the_Mojave_Desert; California Energy Commission, Commission Decision, Russell City Energy Center (July 2002, P800-02-007). Solar PV plants, depending on the type of cells used and construction techniques, can require over 12 acres per MW. See U.S. Department of Energy, Energy Efficiency and Renewable Energy, PV FAQs, http://www.nrel.gov/docs/fy04osti/35097.pdf. Depending on the location of the solar resource, acquiring then blanketing such large areas of land could lead to habitat destruction.

Finally, solar energy technologies like PV, cannot provide full-time availability due to the natural intermittent availability of sunlight. The inflexible and non-dispatchable nature of solar generation – its limited dependability (to produce power when it's needed) – are defining differences between that electricity generating alternative and the Project.

One other technical consideration should be mentioned when considering alternatives such as solar or wind and that is energy storage. Invenergy has energy storage facilities and has used this technology in conjunction with some of our wind facilities. The technology involves the use of batteries and can provide power for short periods of time and is used in helping smooth out or regulate the renewable energy source's energy production, However at larger scales is not cost effective or even economically viable to store and produce energy for time frames much beyond one hour. As the time for production increases beyond 30 minutes the number of batteries increases directly. To illustrate one example of this Invenergy's Beech Ridge storage facility which has a capacity to produce 31 MW for short periods or an overall production of 12 MW Hrs. The facility consists of sixteen container sized trailers (8 ft wide by 40 feet long) placed in an array that occupies approximately an half an acre. A facility that was capable of producing 1,000 MW for an hour (1,000 MWHrs) would need to be 83 times the size of Beech Ridge, would encompass approximately 39 acres, would only be able to match the output of the Project for one hour, and would have a capital cost that is more than twice that of the proposed Clear River Energy Center. Today's storage does have a place in that it helps promote reliability, grid resiliency, power quality, increases renewable penetration, but is used for short term applications and cannot meet the long term (more than an hour) capacity needs that are required to be satisfied in order to meet load.

With all the aforementioned characteristics and impacts, i.e., environmental trade-offs, solar energy technologies are considered as infeasible for the Project's objectives.

Biomass Generation

Biomass generation uses a vegetation fuel source such as wood chips (scrap wood from broken pallets and crates, wood waste generated by pruning, trimming or land-clearing activities, forest management activities or dedicated woody crops) or agricultural waste. The fuel is burned to generate steam in a boiler that is then directed to a steam turbine. Biomass facilities generate much greater quantities of air pollutant emissions than combined-cycle natural gas burning facilities on a per-MW basis due to the inherently lower efficiency of the steam-electric generating technology.

In addition, biomass plants are typically sized to generate less than 25 MW, which is substantially less than the capacity of the Invenergy Project, due to the economics of transporting the biomass fuel from distant locations. Accordingly, many biomass facilities would be required to meet the Invenergy's goal of generating approximately 1,000 MW. Land, infrastructure, and transportation impacts would be significantly more damaging to the environment than the proposed Project.

Emissions from the large number of generating units needed to generate the same electric output as the Project would be significantly greater than proposed by Invenergy, and air quality impacts would be

significantly higher, especially for nitrogen oxides, carbon monoxide, volatile organic compounds, and fine particulate matter.

With all the aforementioned characteristics and impacts, biomass energy generation is not a feasible alternative to the Project.

Geothermal

Geothermal technologies use steam or high-temperature water obtained from naturally occurring geothermal reservoirs to drive steam turbine/generators. Geothermal technology is limited to areas where geologic conditions resulting in high subsurface water temperatures occur. There are no viable geothermal resources in the location of the Project site. See generally U.S. Department of Energy, Energy Efficiency and Renewable Energy, Geothermal Maps, http://www1.eere.energy.gov/geothermal/maps.html. Therefore, geothermal technologies are not a feasible alternative to the Project.

Hydropower

Hydropower facilities require large quantities of water (either stored or flowing water) and sufficient topography to allow power generation as water drops in elevation and flows through a turbine to generate electricity. There are no rivers or bodies of water located in close proximity to the Project site that would offer a viable source of water for power generation via flowing water because elevation changes are not present to the degree needed for efficient power generation. In order to create the necessary elevation differential, a full or partial dam (high-impact hydropower) could be constructed in the River and turbines placed inside the structure; however, unless extremely large areas are intended to be flooded to create a high enough dam, the power produced in such fashion would be limited. While hydropower is generally considered to be a baseload power source, except during times of drought, the small size of such a facility in the vicinity of the Project site would not meet Invenergy's objective of making a significant contribution to the replacement and demand needs in the region.

With all the aforementioned characteristics and impacts, hydropower energy generation is not a feasible alternative to the Project.

Energy Efficiency and Conservation

Energy efficiency is appropriate for both end users of electricity and the equipment that produces electricity. As for end users, Rhode Island is already a perennial national leader in end user energy efficiency. In the most recent rankings by the American Council for an Energy Efficient Economy (http://aceee.org/state-policy/scorecard) Rhode Island ranked number 4 in the nation Even if the state continues to work on ways to promote and encourage even greater efficiency efforts for end users it is highly unlikely, or feasible, to rely exclusively on additional end user improvements to energy efficiency as an alternative to the need for new generation, particularly given the announced retirement of significant MW generation in the region, coupled with the ISO/NE forecast for growth in demand over the next several years.

As for energy efficiency for new power generation the technology employed by Invenergy will rank it amongst the most efficient producers of electricity in the United States and the world. This efficiency carries with it important environmental benefits within the region. Specifically, in the NE-ISO, wholesale electricity markets determine which power plants run to meet electricity demand and determine the wholesale price of electricity. Electricity generators offer bids determined by short-term variable costs (include incremental costs of fuel, operation and maintenance, and emission allowances) into auctions administered by NE-ISO, the entity responsible for market operation, NE ISO selects the lowest priced plant one-by-one until electricity demand is met. The last electricity generator selected to meet demand is referred to as the marginal unit. Due to the current and projected price of natural gas, combined-cycle natural gas plants can offer low priced electricity and disrupt the order in which plants dispatch their electricity. The plants most likely to be displaced by the new generation will be those units that are the last to be selected (marginal

units), which tend to be older coal and oil facilities. Therefore, the Invenergy Project will displace old, inefficient coal and oil fired power.

Even when coal and oil plants are included in the dispatch queue, the nature of their operation is inherently inefficient in the current market because they cannot start quickly or cycle up or down quickly. In instances where there are rapid changes in generation demand coal plants will continue to operate until they can be slowly brought to the proper level of generation. As described in more detail below, natural gas combined-cycle plants handle swings in load demand with ease.

10.1.3 No-Action Alternative

Another alternative is the "no action" alternative under which the Project would not be built or operated. In such case, the energy need described above and in Invenergy's Application would not be met or, if met, would necessarily be met using one or more alternate generation sources.

The no-action alternative would also mean that more inefficient generation sources, including those using coal or oil, would not be displaced by the Project and the environmental benefits associated with such displacement would not be realized.

In sum, the no-action alternative, while eliminating all impacts of the Project, would not achieve the benefits of needed reliable electrical energy resources in Rhode Island, especially in light of the overall reduction in air emissions.

TAB 10

Invenergy

1 South Wacker Drive, Suite 1800
Chicago, IL 60606

November 9, 2015

Todd Anthony Bianco, Coordinator
Rhode Island Energy Facilities Siting Board
89 Jefferson Boulevard, Warwick, RI 02888

Re: Clear River Energy Center – Energy Facility Siting Board Application

Dear Commissioners:

Please find the following supplemental information that we are filing in support of our Rhode Island Energy Facility Siting Board (RIEFSB) application for the Clear River Energy Center ("CREC") Project, and to supplement the information that was submitted on October 28, 2015.

Section 2.1: The Applicant and Affiliates. Invenergy Thermal Development LLC is a Delaware Limited Liability Company and is authorized to do business in Arizona, Florida, and Texas. The project company for the CREC project is Clear River Energy LLC a Delaware Limited Liability Company authorized to do business in Rhode Island. Invenergy Thermal Global LLC (a Delaware LLC) is the parent company of both Clear River Energy LLC and Invenergy Thermal Development LLC.

Section 5: Project Benefits. Please find attached a letter, dated November 4, 2015, from PA Consulting Group, Inc. and Professor Edinaldo Tebaldi that further discusses the direct economic development and employment expectations of the CREC Project. We have also included a revised Section 5.1, 5.1.1 and 5.1.2. These changes were made to more clearly define direct jobs and more clearly distinguish direct jobs from indirect jobs.

Section 7: Assessment of Need. Please find two redacted supplemental reports prepared by PA Consulting Group, Inc. providing additional information supporting the data in Section 7.0, regarding the Assessment of Need for the CREC Project. Please note we are filing the full report separately, under seal, with a Motion for Confidential Treatment.

Section 10: Study of Alternatives. A copy of the referenced report in Section 10 (on page 124), listed as "ISO New England Installed Capacity Requirement, Local Sourcing Requirements and Capacity Requirement Values for the System-Wide Capacity Demand Curve for the 2018/19 Capacity Commitment Period", is attached.

Figures and Site Drawings. CREC will provide plans prepared to date under separate cover and will include 16 copies of full sized drawings of the following plans:

1. Cover Sheet (with Drawing List and Rendering included)
2. Single Shaft Site Arrangement (238926-0GA-C1000 Rev. 0)
3. Single Shaft General Arrangement (238926-0GA-C1001 Rev. 0)
4. Single Shaft Construction Facilities and Terminal Point Location Plan (238926-0GA-C1002 Rev. 0)
5. Administration Building Floor Plan (238926-0GA-A1000 Rev. 0)
6. Clear River Energy Center Overall One-Line Diagram (238926-0MP-E1000 Rev. 0)

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7. Water Balance Diagrams
   a. Natural Gas Fired Water Mass Balance – Average Ambient Conditions (238926-WMB-01 Rev. C)
   b. Natural Gas Fired Water Mass Balance – Summer Ambient Conditions (238926-WMB-03 Rev. C)
   c. Water Mass Balance – 1 CT on Gas, 1 CT on Fuel Oil – Winter Ambient Conditions (238926-WMB-04 Rev. C)
8. Site Topography (238926-0GA-C1004 Rev. A)
9. Wetland Delineation (238926-0GA-C1005 Rev. A)
10. Site Boundary (238926-0GA-C1006 Rev. A)
11. Site Grading Plan (238926-0GA-C1007 Rev. A)

Section 11: Permits. An updated list of expected permits and licenses (to amend the table in Section 11.4):

Table 11.4-1

List of Required Project Licenses & Permits

Agency	License/Permit
RIEFSB	License to Construct a Major Energy Facility
Town of Burrillville	Special Permit/Subdivision Approvals
Town of Burrillville	Building/AST Permits
Town of Burrillville	Industrial Wastewater Discharge Permit
RIDEM	Major Source/PSD Air Permit
RIDEM	Title V Operating Permit
RIDEM	CO2 Budget Permit
EPA	Acid Rain Permit
RIDEM	Water Diversion Permit
RIDEM	Order of Approval (Wastewater Treatment)
RIDEM	RIPDES Multi-Sector General Permit (Industrial Stormwater)
RIDEM	RIPDES General Permit (Construction Stormwater)
RIDEM	Permit to Alter a Freshwater Wetland
RIDEM	Water Quality (Wells)(Pascoag Utility District)
RIDOH	Water Quality/Withdrawals (Wells)(Pascoag Utility District)
ACOE	Individual Permit (Wetlands)
FAA	Determination of No Hazard to Air Navigation
CRMC	Preliminary Determination for Waiver of Asset Requirement*
RI Historical	Section 106 and State Historical Assessment

Best Regards,

Invenergy

1 South Wacker Drive, Suite 1800
Chicago, IL 60606

John E. Niland
Director, Thermal Development

cc: Richard R. Beretta, Jr.
Alan M. Shoer

* Attached to this letter is a copy of the Request for a Waiver of Assent filed with the R.I. CRMC.

Attachments:

1. Revised Section 5.1, 5.1.1 and 5.1.2. Project Benefits
2. PA Memo on Capacity Prices
3. PA Memorandum on Clear River
4. PA Memorandum on Clear River Employment Impacts
5. ISO New England Report on Installed Capacity Requirement, Local Sourcing Requirements and Capacity Requirement Values for the System-Wide Capacity Demand Curve for the 2018/19 Capacity Commitment Period February 2015
6. Request for a Waiver of Assent filed with the R.I. CRMC

TAB 11

5.0 PROJECT BENEFITS

5.1 Economic Benefits

To characterize and evaluate the economic development impacts resulting from the construction and ongoing operation of the 1,000 MW Clear River natural gas-fired combined cycle generation facility, Invenergy retained the services of Professor Edinaldo Tebaldi and PA Consulting Group ("PA").

Dr. Tebaldi is an associate professor of economics at Bryant University. He also serves as the Rhode Island forecast manager for the New England Economic Partnership (NEEP). He is an applied econometrician with research interests in economic growth, development, and labor market outcomes. Dr. Tebaldi has published several articles in refereed journals and co-authored a number of economic impact assessment studies and reports analyzing economic conditions across New England States.

PA's Global Energy & Utilities practice regularly performs power market analyses and evaluates the economics of power generating assets across the U.S., including the New England power market. PA understands the economic development considerations associated with power generation investment and utility power procurement, and has used input-output models to evaluate the economic impacts driven by such decisions.

This subsection introduces the methodology and projected impacts on employment, wages, and the overall economy in Rhode Island and the surrounding area.

5.1.1 Overview

As is typically the case with generation facilities, Clear River will drive significant economic impacts in the State of Rhode Island. Economic development impacts associated with the Project will result from the following three areas:

1. Construction of the facility – Equipment, materials, and labor employed during construction as well as state sales tax, permitting fees, and other activities.
2. Ongoing operation of the facility – Fixed and variable costs associated with the materials and labor needed to operate the facility as well as annual property taxes.
3. Power market cost savings to Rhode Island ratepayers – The addition of new efficient generation capacity in Rhode Island will result in lower capacity and power prices in the near term, thereby driving significant savings to Rhode Island ratepayers during the plant's early years. From 2019-2022, cumulative savings to the Rhode Island customer are projected to be greater than $280 million, or approximately $70m annually. PA has evaluated the induced economic effects on the Rhode Island economy associated with these near-term electricity customer cost savings.

5.1.2 Methodology

To estimate the magnitude of the resulting economic impacts, this study uses input-output (I-O) analysis. I-O analysis accounts for inter-industry relationships within a city, state, or expanded area, and employs the resulting economic activity multipliers to estimate how the local economy will be affected by a given investment (in this case the construction and ongoing operation of the 1,000 MW Clear River facility).

Multiplier analysis is based on the notion of feedback through input-output linkages among firms and households who interact in regional markets. Firms buy and sell goods and services to other firms and pay wages to households. In turn, households buy goods from firms within the economic region. Thus, the economic impact of Clear River spreads to other local businesses through direct purchases from them as well as from purchases of locally produced goods and services, which arise from the income derived by the employment that is created. Further impacts occur because of feedback

effects – where other local firms require more labor and inputs to meet rising demand for their output, which has been stimulated by Clear River construction and operation.

The economic impact of Clear River construction and operation can be categorized as follows:

1. Direct Effects – Jobs, income, output and fiscal benefits that are created directly by the construction and ongoing operations of Clear River. The jobs (and other benefits) that are created may be short-term, as in the case of construction jobs, or long-term, such as the operations and maintenance positions that exist throughout the life of the generation facility.
2. Indirect Effects – Jobs, income, output and fiscal benefits that are created throughout the supply chain and that are spawned by the direct investment to build and operate the facility. Indirect jobs include the jobs created to provide the materials, goods, and services required by the construction and operation of Clear River, as well as the jobs created to provide the goods and services paid for with the wages from the direct jobs.
3. Induced Effects – Jobs, earnings, and output and fiscal benefits created by household spending of income earned either directly from Clear River or indirectly from businesses that are impacted by Clear River.

There is significant complexity involved in the calculation of these effects, particularly in the calculation of the indirect and induced effects, but comprehensive estimates of economic impacts require all three. These estimates are also sensitive to the set of assumptions considered in the study, principally assumptions regarding the leakage of economic activity outside the state. In addition, a series of variables, including changes to the price of electricity, will influence the multiplier benefit analysis and therefore have been considered in tandem to assess the true contribution of Clear River to the Rhode Island economy.

5.1.2.1 Input-Output Models Employed

The job creation, earnings, and overall economic impact of Clear River on Rhode Island have been analyzed using project cost specifics and two input-output models: IMPLAN and the National Renewable Energy Lab's Jobs and Economic Development Impact model (JEDI).

IMPLAN is an economic analysis tool that takes data from multiple government sources and employs an estimation method based on industry accounts or Input-Output Matrix that allows using multipliers to make estimations of how changes in income and spending impact the local economy. IMPLAN estimates are generated by interacting the direct economic impact of Clear River with the Regional Input-Output Modeling System (RIMS II) multipliers for Rhode Island. The U.S. Bureau of Economic Analysis (BEA) provides these multipliers.

The Jobs and Economic Development Impact (JEDI) model estimates the economic impact of constructing and operating power generation plants at the state level. The JEDI model also uses an input-output methodology and was built utilizing economic data from IMPLAN. The JEDI model allows estimating of the economic impact of power generation investment in a state including local labor, services, materials, other components, fuel, and other inputs. The model also allows adjusting the portion of project investment that occurs locally.

5.1.2.1 Modeling Assumptions

As discussed above, the JEDI and IMPLAN estimates are sensitive to the set of assumptions utilized in the model, particularly the portion of project investment that occurs locally (local share). Through local share percentages, the model allows accounting for the leakage of economic activity outside the state's border. Table 5.1-1 presents the local shares for the construction phase that were used to estimate the economic impact of Clear River on Rhode Island only. These parameters are consistent with those utilized in other similar studies and were adjusted to match Rhode Island's specific conditions. For instance, 100 percent of the spending with turbines

(power generation) is paid to vendors outside Rhode Island. On the other hand, the model assumes that 87% of the construction labor required to construct the facility will be sourced from within Rhode Island.

Table 5.1-1:
Local Share – Construction Phase

Item	Local Share
Facility and Equipment	
Power Generation	0%
General facilities	75%
Plant Equipment	5%
Labor and Management	
Construction Labor	87%
Project management (construction and owner's)	16%
Others	
Engineering/Design	17%
Construction insurance	0%
Land	100%
Permitting Fees	100%
Grid intertie	25%
Spare Parts	5%
Sales Tax (Materials & Equipment Purchases)	100%

Table 5.1-2 provides the local shares utilized to calculate the economic impact of the ongoing operation of the Clear River facility. It is worth noting that 100% of the spending on natural gas fuel (the commodity itself) will be paid to vendors outside Rhode Island. However, it also worth noting that 100% of the labor and 85% of the services, two major sources of ongoing spending and investment for a generation facility, are assumed to be sourced from State of Rhode Island business.

Table 5.1-2:
Local Share – Operations and Maintenance Phase

Item	Local Share
Fixed Costs	
Labor	100%
Materials	25%
Services	85%
Variable Costs	
Water	100%
Catalysts & chemicals	85%
Fuel Cost	0%

The economic impact analysis also incorporates power market cost savings to Rhode Island ratepayers. The addition of new efficient generation capacity in Rhode Island will result in lower

capacity and power prices for Rhode Island ratepayers in the near term, thereby driving significant savings to Rhode Island ratepayers during the plant's early years. These power market cost savings were determined by comparing Rhode Island's portion of energy and capacity market costs under modeling scenarios completed 1) with Clear River at 1,000 MW-net, and 2) without Clear River.

5.1.3 Economic Development Impacts

The construction, ongoing operation, and near-term ratepayer savings resulting from the Project will create jobs and drive significant economic development, both in Rhode Island and throughout the Northeast region.

The estimates in this section include the direct, indirect, and induced impacts of Project construction, ongoing operation, and ratepayer bill savings on Rhode Island's economy.

5.1.3.1 Economic Impacts – Rhode Island Only

To evaluate the economic impacts of Clear River within Rhode Island, input-output analysis was completed according to the local share percentages introduced in Section 5.1.2.1.

Table 5.1-3 reports the direct annual job creation and earnings of Clear River on the State of Rhode Island. It shows that construction of Clear River is expected to generate 388 jobs in 2017 and 492 jobs in 2018. Facility operations will create 25 onsite (direct) jobs and approximately $2 million in earnings annually from 2020 through 2034. Note that the figures in Table 5.1-3 do not include the jobs and earnings associated with the contractors and service professionals that will be involved in the regular operation and maintenance of the facility. These indirect impacts of Clear River are included in Table 5.1-4.

Table 5.1-3:
Economic Development – Direct Impact, Rhode Island, 2016-2034

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Direct Employment Impact (FTEs per year)																			
Construction Period	26	388	492	129	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Facility Operations	0	0	0	15	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
Direct Earnings Impact ($ - millions)																			
Construction Period	4.5	68.5	88.7	23.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Facility Operations	0.0	0.0	0.0	1.0	1.7	1.7	1.8	1.8	1.8	1.9	1.9	2.0	2.0	2.0	2.1	2.1	2.2	2.2	2.3

Table 5.1-4 reports the total *(direct, indirect, and induced)* annual job creation, earnings, and overall economic impact of Clear River on the State of Rhode Island. It is important to note that the most significant economic impacts will be realized in the early years of the Project: the construction of Clear River facility will bring significant investment and construction activity to Rhode Island from 2016 to 2019, and the first four years of operation will produce substantial energy and capacity cost savings to customers.

Table 5.1-4:
Economic Development - Results Summary, Rhode Island Only, 2016-2034

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Employment Impact (FTEs per year)																			
Construction Period	49	734	930	245	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Facility Operations	0	0	0	85	145	145	145	145	145	145	145	145	145	145	145	145	145	145	145
Cost Savings to Customer	0	0	0	498	733	419	159	0	0	0	0	0	0	0	0	0	0	0	0
Total Employment Impact	**49**	**734**	**930**	**827**	**878**	**564**	**304**	**145**	**145**	**145**	**145**	**145**	**145**	**145**	**145**	**145**	**145**	**145**	**145**
Earnings Impact ($ - millions)																			
Construction Period	5.9	90.7	117.4	31.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Facility Operations	0.0	0.0	0.0	6.6	11.5	11.8	12.0	12.3	12.6	12.8	13.1	13.4	13.7	14.0	14.3	14.6	14.9	15.3	15.6
Cost Savings to Customer	0.0	0.0	0.0	26.3	39.5	23.5	9.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Earnings Impact	**5.9**	**90.7**	**117.4**	**64.5**	**51.1**	**35.3**	**21.0**	**12.3**	**12.6**	**12.8**	**13.1**	**13.4**	**13.7**	**14.0**	**14.3**	**14.6**	**14.9**	**15.3**	**15.6**
Economic Output ($ - millions)																			
Construction Period	8.9	137.1	177.4	47.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Facility Operations	0.0	0.0	0.0	18.1	31.8	32.5	33.2	33.9	34.7	35.5	36.2	37.0	37.8	38.7	39.5	40.4	41.3	42.2	43.1
Cost Savings to Customer	0.0	0.0	0.0	75.3	113.2	66.1	25.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Economic Output	**8.9**	**137.1**	**177.4**	**141.2**	**145.0**	**98.6**	**58.9**	**33.9**	**34.7**	**35.5**	**36.2**	**37.0**	**37.8**	**38.7**	**39.5**	**40.4**	**41.3**	**42.2**	**43.1**

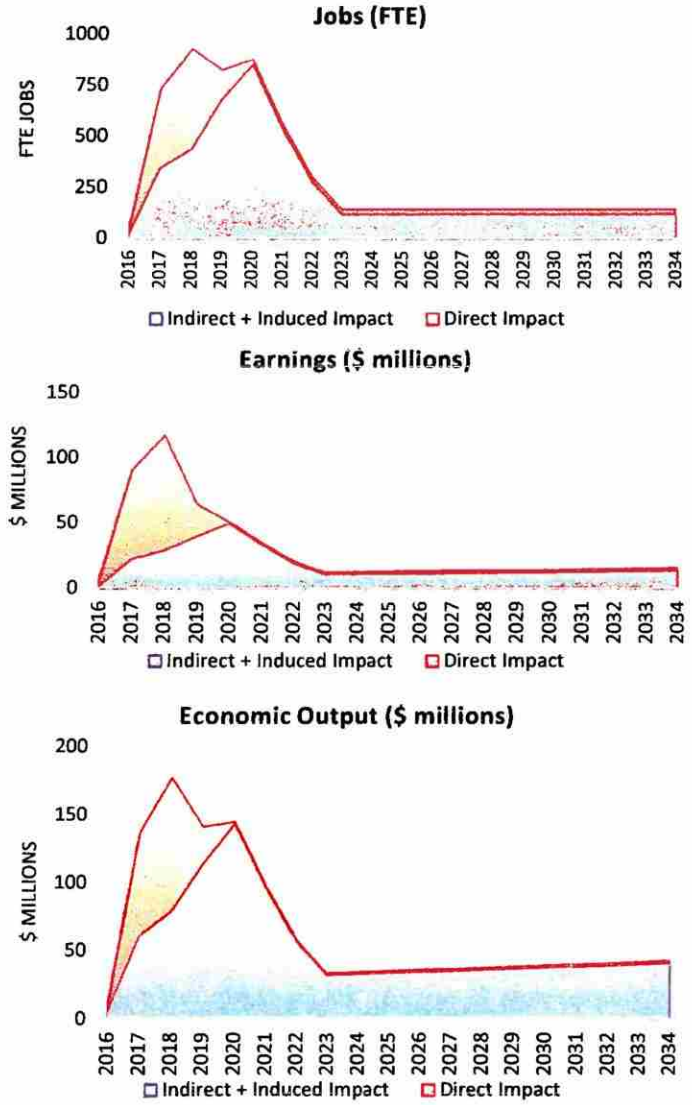
In summary, the job creation, earnings, and overall economic impact of the Project on the State of Rhode Island are projected as follows:

- **Rhode Island jobs** – From 2017-2021, which includes the most intense two years of construction and the first years of operation, Clear River will support the creation of just under 800 full-time jobs per year. The construction and operation of Clear River alone – i.e. not including the electricity cost savings to the customer – will create an average of more than 660 full-time jobs per year from 2017-2019 and 145 full-time jobs per year from 2020 to 2034 in Rhode Island.
- **Rhode Island earnings** – From 2017-2021, Clear River will support the creation of approximately $360 million in earnings to Rhode Island workers, or more than $70 million per year. Earnings to Rhode Island employees as a result of Clear River will total more than $550 million from 2016-2034.
- **Rhode Island economic output** – From 2017-2021, the total economic impact on Rhode Island is projected to be $700 million, or approximately $140 million per year. The overall impact of Clear River on the Rhode Island economy will total more than $1.2 billion from 2016-2034, or an average of $65 million annually.

Figure 5.1-1 provides a breakdown of the direct impacts versus the indirect and induced impacts of Clear River construction and ongoing operations.

The direct economic impacts themselves will be significant, realized in the form of jobs, income, output and benefits created directly by the construction and ongoing operations of Clear River. In addition, Clear River will generate significant economic activity in Rhode Island through input-output linkages among firms and households who are affected by its construction and operations. From 2016-2034, the indirect and induced economic impact of Clear River on the Rhode Island economy will total $990 million, approximately 80% of the total output creation.

Figure 5.1-1:
Direct vs Indirect/Induced Economic Impacts – Rhode Island Only



Similarly, approximately 61% of the $550 million in earnings that Clear River will generate in the state from 2016 to 2024 will be indirect and induced earnings, and the jobs chart demonstrates that 76 percent of the jobs supported by Clear River will be induced and indirect jobs. Overall, the impact estimates suggest that Clear River operation and demand for local services and materials will have a significant multiplier effect on the state economy. This multiplier effect will be particularly strong for output creation.

5.1.3.2 Economic Impacts - Rhode Island and Surrounding Region

Significant economic impacts will accrue outside of Rhode Island as well. Project needs that cannot be met within Rhode Island – most notably generation equipment that is not currently

manufactured within the state – will drive job creation and economic development in surrounding states. To evaluate the economic impacts of Clear River on Rhode Island and the surrounding region, input-output analysis was completed with all local share percentages introduced in Section 5.1.2.1 set to 100% except for fuel, which was kept at 0%. In other words, this scenario is designed to evaluate the approximate the economic impact of the construction and ongoing operation of Clear River on Rhode Island and the surrounding region, but excludes the U.S. impact associated with ongoing natural gas procurement.

Table 5.1-5 presents the impact estimates of the plant on the economy as a whole.

Table 5.1-5:
Economic Development Results Summary, RI and Surrounding Region, 2016-2034

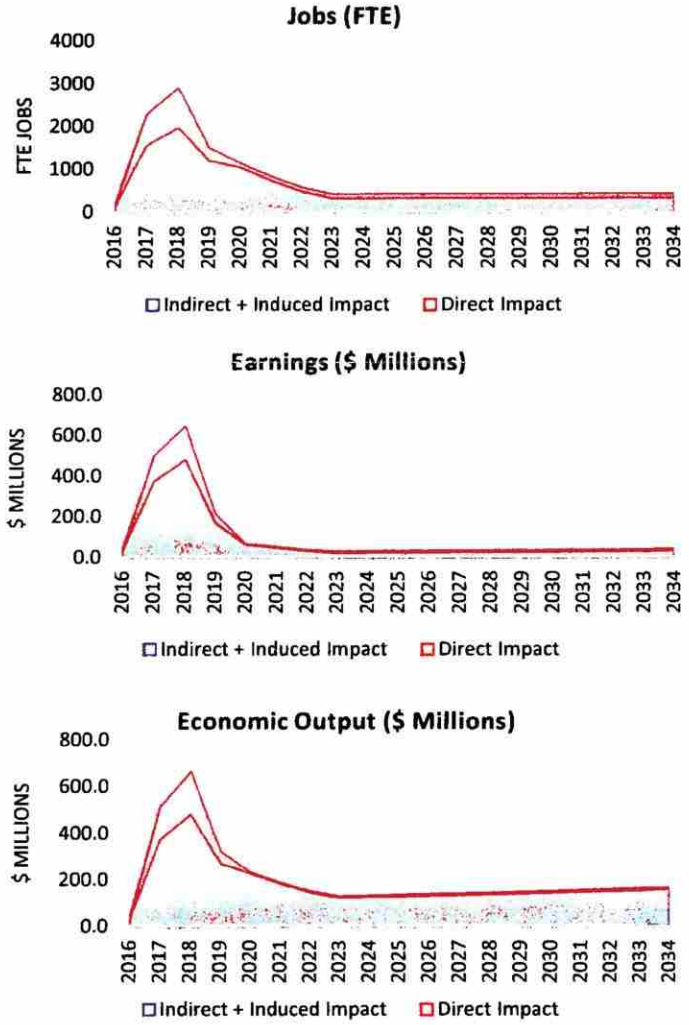
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Employment Impact (FTEs per year)																			
Construction Period	154	2306	2921	769	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Facility Operations	0	0	0	253	433	433	433	433	433	433	433	433	433	433	433	433	433	433	433
Cost Savings to Customer	0	0	0	498	733	419	159	0	0	0	0	0	0	0	0	0	0	0	0
Total Employment Impact	**154**	**2306**	**2921**	**1519**	**1166**	**852**	**592**	**433**	**433**	**433**	**433**	**433**	**433**	**433**	**433**	**433**	**433**	**433**	**433**
Earnings Impact ($ - millions)																			
Construction Period	32.7	501.0	648.6	174.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Facility Operations	0.0	0.0	0.0	16.6	29.2	29.8	30.5	31.1	31.8	32.5	33.2	34.0	34.7	35.5	36.2	37.0	37.9	38.7	39.5
Cost Savings to Customer	0.0	0.0	0.0	26.3	39.5	23.5	9.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Earnings Impact	**32.7**	**501.0**	**648.6**	**217.4**	**68.7**	**53.3**	**39.4**	**31.1**	**31.8**	**32.5**	**33.2**	**34.0**	**34.7**	**35.5**	**36.2**	**37.0**	**37.9**	**38.7**	**39.5**
Economic Output ($ - millions)																			
Construction Period	33.6	515.2	667.0	179.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Facility Operations	0.0	0.0	0.0	69.8	122.3	125.0	127.7	130.5	133.4	136.3	139.3	142.4	145.5	148.7	152.0	155.4	158.8	162.3	165.8
Cost Savings to Customer	0.0	0.0	0.0	75.3	113.2	66.1	25.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Economic Output	**33.6**	**515.2**	**667.0**	**324.5**	**235.4**	**191.0**	**153.4**	**130.5**	**133.4**	**136.3**	**139.3**	**142.4**	**145.5**	**148.7**	**152.0**	**155.4**	**158.8**	**162.3**	**165.8**

Excluding the significant U.S. jobs impact associated with ongoing natural gas procurement, the economic impact of the plant on the economy as a whole (this time not limited to Rhode Island) is projected as follows:

- **Jobs:** The Project will support an average of approximately 770 full-time jobs per year from 2016-2034, with an average of approximately 1,750 full-time jobs created annually from 2017-2021, the most intense two years of construction and the first years of operation.
- **Earnings:** The Project will create nearly $2 billion in total earnings from 2016-2034.
- **Economic Output:** The Project will generate approximately $3.9 billion in total economic output from 2016-2034.

Figure 5.1-2 provides a breakdown of the direct impacts versus the indirect and induced impacts of Clear River construction and ongoing operations. The direct impacts are fairly similar in magnitude to those in the Rhode Island only analysis because most direct economic effects from the facility are realized within the state, but the total output is approximately three times as large and the indirect and induced impacts account for a much larger percentage of the economic impacts in this case.

Figure 5.1-2:
Direct vs Indirect/Induced Economic Impacts – Rhode Island and Surrounding Region



TAB 12

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July 29, 2015

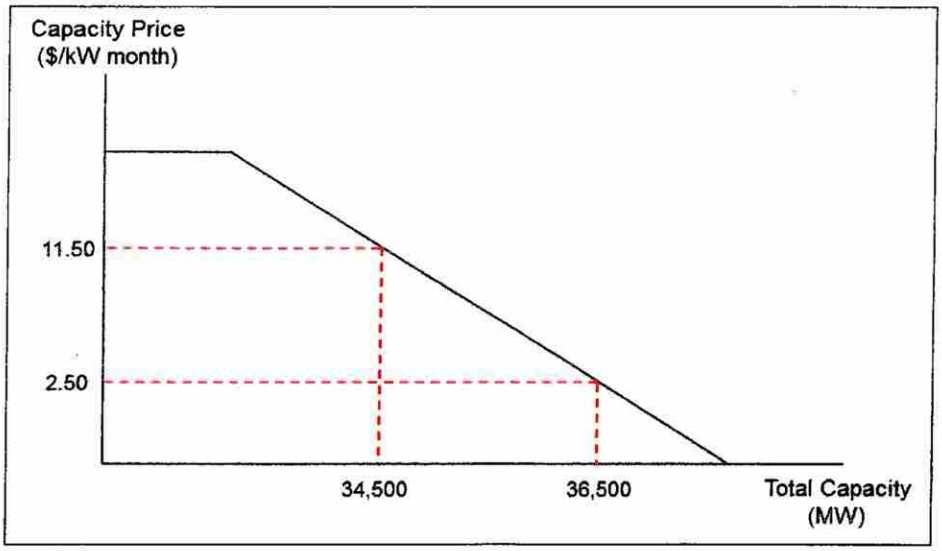
To Whom It May Concern,

At the request of Invenergy LLC (Invenergy), PA Consulting Group, Inc. (PA) has prepared this memorandum describing (i) PA's methodology for projecting capacity prices for the upcoming 2019/20 Forward Capacity Auction (i.e. FCA 10); and (ii) how that price projection compares to actual capacity prices from FCA 9. PA's capacity price forecast for FCA 10 was used to develop the cash flow projections of the Clear River natural gas-fired combined cycle power plant, currently under development by Invenergy.

Methodology

PA's capacity price forecast was based on its forecasts of (i) existing and new capacity (i.e., total capacity); and (ii) FCA 10 demand curve parameters. The demand curve parameters effectively determine the capacity price based on a given amount of capacity. All else equal, the higher the total capacity the lower the capacity price. This mechanism is illustrated in Figure 1 below.

Figure 1: Capacity Price Derivation - Illustrative



[redacted]

For FCA 10, PA projected existing capacity based on capacity from FCA 9, and new capacity reflecting Clear River bidding approximately [redacted] MW into FCA 10.[1] This resulted in a projection of total capacity for FCA 10 of [redacted] MW. (In comparison, the total capacity in FCA 9 was 34,694 MW.) When the total capacity of [redacted] MW was overlaid against PA's forecast of the FCA 10 demand curve the resulting capacity price was [redacted]. The [redacted] represents PA's projection of capacity prices for all capacity resources in New England for FCA 10.

FCA 9 Comparison

In FCA 9, new capacity resources located in Rhode Island (i.e., the Medway peaker in Massachusetts) received a capacity price of $17.73/kW-mo. This extremely high price was due to the Southeastern Massachusetts/Rhode Island (SEMA/RI) capacity zone having less capacity than was needed for reliability; the zone had a deficit of approximately 250 MW. This caused the Forward Capacity Auction's Inadequate Supply rule to be triggered (since the zone had less capacity than needed for reliability). If the Inadequate Supply rule had not been triggered, new capacity resources in Rhode Island would have likely received the Rest-of-Pool (ROP) clearing price of [redacted]W-mo, instead of the $17.73/kW-mo. PA does not project the Inadequate Supply rule to be triggered in FCA 10 for several reasons:

- In FCA 10, ISO New England is planning to combine the SEMA/RI zone with the Northeastern Massachusetts/Boston (NEMA/Boston) zone to form a new, larger zone – called the Southeastern New England (SENE) zone.
- In FCA 9, NEMA/Boston had more capacity than was needed for reliability.
- Clear River is projected to participate in FCA 10, bidding approximately [redacted] MW into the new SENE zone.

With SEMA/RI being combined with NEMA/Boston and Clear River projected to bid approximately [redacted] MW, PA projects the new SENE zone will have more capacity than is needed for reliability in FCA 10. Consequently, the Inadequate Supply rule that was triggered in FCA 9 is not projected to be triggered in FCA 10.

Additionally, in FCA 9, capacity resources outside of the SEMA/RI zone (i.e., the Towantic combined cycle in Connecticut) received the ROP capacity price of $9.55/kW-mo. However, as previously mentioned, PA's projection for FCA 10 total capacity is [redacted] MW – which is approximately [redacted] MW higher than the total capacity in FCA 9 (34,695 MW). Since capacity prices are inversely correlated to total capacity – as illustrated in Figure 1 – PA's projection for capacity prices in FCA 10 is lower than FCA 9.

Conclusions

PA projects FCA 10 capacity prices for capacity resources in Rhode Island and across New England to be significantly lower than FCA 9 capacity prices - resulting in significantly lower

---

[1] In addition to Clear River's capacity, PA assumes approximately [redacted] MW of incremental renewable and demand response capacity.

[redacted]

capacity revenues for Clear River than if it had participated in FCA 9. For example, the FCA 10 capacity revenues projected to be earned by Clear River (based on a capacity price of [redacted]) are approximately [redacted] million lower than they would be if Clear River had received Medway's FCA 9 capacity price, and approximately [redacted] million lower than they would be if Clear River had received Towantic's FCA 9 capacity price.

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June 16, 2015

To Whom It May Concern,

At the request of Invenergy LLC ("Invenergy"), PA Consulting Group, Inc. ("PA") prepared this memorandum describing PA's analysis of Invenergy's proposed [redacted] **MW summer-rated Pascoag** Energy Center natural gas-fired combined cycle development project (the "Project" or "PEC"), to be located in Burrillville, Rhode Island and which would operate in the New England electricity market ("ISO-NE"). This memorandum summarizes PA's analysis, and provides an overview of PA's underlying market assumptions and modeling methodology as well as PA's projections of PEC's operations and energy margins.

Background

Figure 1: PEC's Location in ISO-NE[1]

PEC is a proposed summer-rated [redacted] MW natural gas-fired combined cycle power plant to be located in Burrillville, Rhode Island. See Figure 1. The Project has a planned commercial online date of June 2019 and would utilize [redacted]. The facility is projected to have a summer full load **heat rate of** [redacted] Btu/kWh and be interconnected into the Rhode Island zone of the ISO-NE power market. See Appendix Table A-5 for an overview of PEC's assumed dispatch characteristics.

As part of its work, PA developed a monthly 20-year forecast (2019 through 2038) of the ISO-NE power market and a 20-year forecast (2019 through 2038) of PEC's operations and cash flows. Unless otherwise noted, all numerical values are in nominal dollars in this memorandum.[2]

Modeling methodology overview

PA has a robust, well-developed, and industry-tested fundamental modeling process, including its proprietary stochastic dispatch optimization, capacity compensation, environmental, renewable, and valuation models along with the use of production cost, transmission, and natural gas models that are operated by PA's subject matter experts and populated with PA proprietary data. See Figure 2.

PA utilizes [redacted] for its production cost modeling in order to dispatch generation units to minimize total system cost, and PA analyzes both fixed and future capital costs required to meet

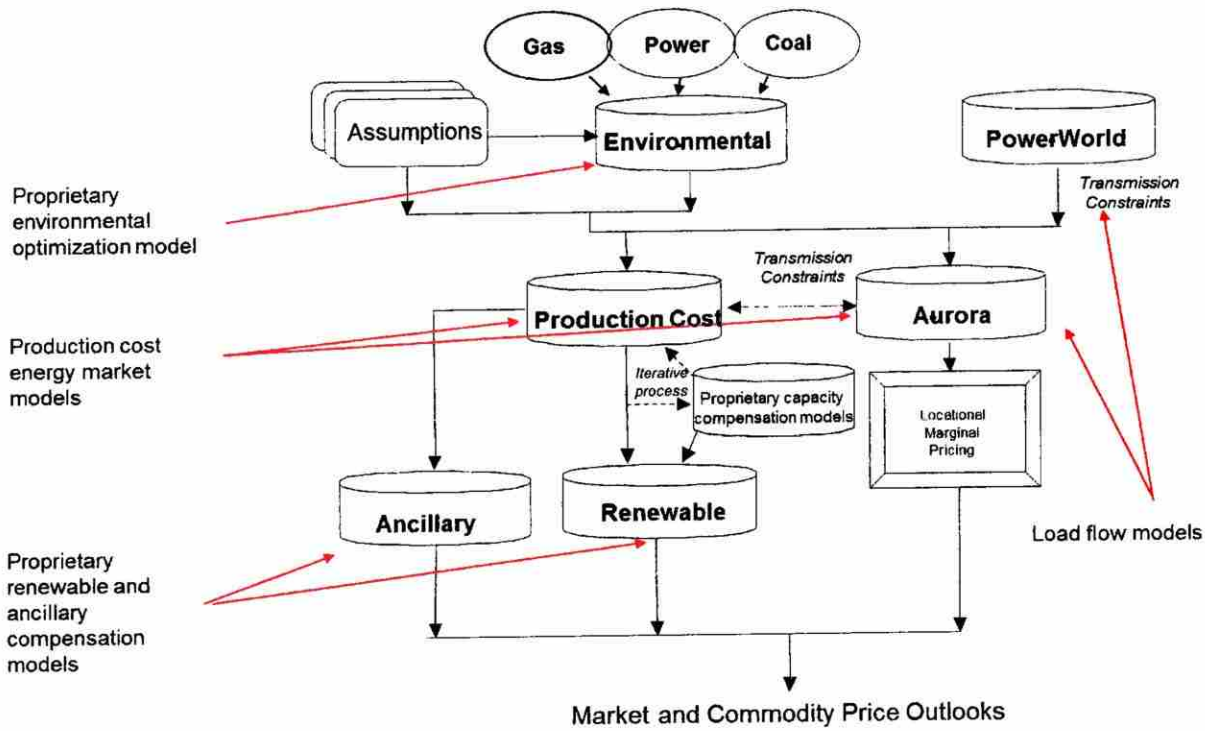
[1] Source: PA Consulting Group and copyrighted material excerpted from Ventyx's *Velocity Suite* Energy Map.
[2] PA assumes an inflation rate of 2.2% per annum.

[redacted] [redacted]

electric demand and ensure system reliability. The latter analysis results in a projection of incremental compensation required to maintain reliability, which existing generation should be measured against. PA's proprietary environmental optimization model integrates the natural gas-power-coal sectors, as well as the coal generator capital expenditure versus coal selection and resulting emission price, paradigms.

PA also utilizes its proprietary stochastic model to assess specific generator operations and economics relative to the electric system and under power purchase agreements, as necessary, as well as assess financial hedges and fuel transportation rights.

Figure 2: PA's Fundamental Modeling Process[4]



[3] [redacted]

[4] The illustration in this figure does not include PA's stochastic dispatch model, which was used to forecast hourly (4-hour block basis) Project-level production and energy and ancillary margins.

[redacted] [redacted]

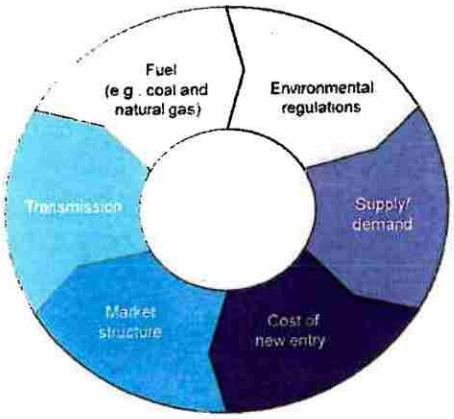
Key modeling assumptions

PA views power markets within the context of six key value drivers (i.e., major assumptions) that are directly integrated into PA's fundamental market modeling process. These key drivers include market structure, fuels (i.e., natural gas and coal), environmental regulations, supply and demand, cost of new entry, and transmission. See Figure 3.

i. Market structure

As one of the first power markets to institute an ISO, the New England power market is among the most developed energy markets in the United States. ISO-NE operates as a fully functional RTO, coordinating, monitoring, and directing the operation of the market's transmission system as well as its power generating facilities. The New England power market covers the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont, and is divided into eight load zones.

Figure 3: Key Market Drivers



PA's analysis assumes all current ISO-NE energy, ancillary and capacity market rules as its base case view.

ii. Fuels

Fuel prices impact the projected dispatch cost of thermal power generating assets as well as the resource planning decisions of retail electric providers. The fuel of primary importance in ISO-NE is natural gas (and, to a lesser extent, fuel oil).

Despite having multiple procurement options and being located less than 200 miles away from the Marcellus shale play, ISO-NE is among the most gas-constrained regions in the country. Recent factors, including declining Eastern Canadian production and reduced Liquefied Natural Gas ("LNG") deliveries due to the expiry of long term supply contracts, have exacerbated winter price spikes as evidenced in the winters of 2012/13 and 2013/14. During the shoulder and summer months, there is typically sufficient pipeline capacity on the interstate pipelines to meet regional demand.

Historically, natural gas prices in major Northeast markets have experienced severe seasonal volatility. In the past several years, price volatility in ISO-NE – specifically Boston – has increased. However, other Northeast markets, such as New York and New Jersey, have decreased in volatility. This decline is attributable to several natural gas pipeline projects, such as Spectra's NY-NJ project and the proposed Constitution pipeline, which have and will alleviate some of the persistent regional transportation constraints. While these projects will alleviate historic constraints into the broader New Jersey and New York City market, limited progress has been made on expansions further downstream into ISO-NE creating a widening price differential between these markets during constrained winter periods.

As more takeaway capacity is brought to ISO-NE through additional expansions, further year-round basis declines can be expected – driven primarily by basis reductions during winter months. While

the basis differential is expected to narrow in the long-term, PA expects that Algonquin Citygate (the natural gas pricing point of primary importance in ISO-NE) will continue to trade at a premium. See Table 1.

[redacted]

a. *PEC fuel sourcing*

[redacted]

This supply arrangement affords PEC the ability to source approximately [redacted]%, on average, of its natural gas needs directly from the Marcellus at Leidy-type pricing, which is expected to continue trading at a significant discount to Algonquin Citygate throughout the study period, driven by its location in the heart of the Marcellus shale play. See Table 2. On average, this supply arrangement, excluding fixed transport charges, results in the Project sustaining an approximately [redacted] discount in delivered natural gas costs compared to natural gas-fired competitors taking [redacted]% of deliveries off of the Algonquin pipeline.

[redacted] [redacted]

PA's base case reflects this proposed fuel procurement strategy. Energy margin projections (shown in Figure 6) are net of associated fixed transport charges (assumed to be approximately [redacted] Dth based on discussions between Invenergy and owners of the Millennium and Algonquin pipelines).

[redacted]

iii. Environmental regulations

Power generating assets are currently subject to local, state, and federal laws for emissions, including sulfur dioxide ("SO_2"), nitrogen oxide ("NOx"), particulate matter ("PM"), mercury ("Hg") and other hazardous air emissions. Federal regulation by the EPA is currently in various stages of review to further limit SO_2, NOx, particulate matter, mercury and other hazardous air emissions as well as coal combustion ash disposal and plant water intake/discharge practices. Meanwhile, legislation to limit greenhouse gas ("GHG") emissions (including CO_2) has all but stalled at the Congressional level, while the EPA continues to take steps in developing federal GHG oversight and limits for new and existing facilities. In the absence of federal legislation, regional GHG programs in the United States have been implemented, but in limited fashion. While directly or indirectly affecting all power generators, these regulations disproportionately affect coal-fired resources.

PA's analysis takes into consideration all major national and regional environmental regulations applicable to power generation. Key regulations include:

[redacted]

Sulfur dioxide, nitrogen oxides and particulate matter. PA's analysis assumes Cross-State Air Pollution Rule ("CSAPR") regulations beginning in 2015. It is PA's assumption that CSAPR (or any future replacement) regulations will be primarily implemented at the state level (or company-owned portfolio level) and will likely not result in widespread interstate trading, although some small amount of regional trading may emerge. The practical effect on the industry, except on the periphery, is likely to be relatively minimal when compared to the impact of other current and pending EPA rules.[5] See Appendix Table A-2(b).

Mercury and air toxics. In December 2011, the EPA published final rules to reduce emissions of mercury and other air toxics, utilizing a Maximum Achievable Control Technology ("MACT") standard, called MATS. In addition to mercury, the rule covers other hazardous air pollutants, including other heavy metals and acid gases. In addition to federal regulation, several states have also enacted state-specific regulations to address mercury emissions from coal power generating assets. PA assumes the EPA's current MATS rule regulation beginning in the 2015-2016 timeframe, with the possibility of delay on a plant-by-plant basis for an additional year, as well as current state regulations governing mercury emissions.

Water intake and discharge. Sections 316(a) and 316(b) of the Federal Water Pollution Control Act (also known as the Clean Water Act) require the EPA to regulate cooling system thermal discharge and intake structures at power plants. In May 2014, the EPA published a final rule that covers existing facilities that withdraw at least 25% of their water from an adjacent body of water exclusively for cooling purposes and have a design intake flow of greater than 2 million gallons per day. While the final rule is generally flexible with regards to compliance options, in some instances it may require existing plants to replace once-through cooling systems with more expensive closed loop systems.

GHG regulation. After multiple failed attempts by Congress to legislate a national greenhouse gas program, the EPA has moved forward with a multi-pronged approach to address GHG emissions. In September 2012, the EPA proposed new rules for the New Source Performance Standard ("NSPS") program that would essentially halt all new development of coal that does not include carbon capture and sequestration.[6] Additionally, in June 2014, the EPA proposed the Clean Power Plan, which seeks to reduce carbon emissions from *existing* power generation by 30% in 2030 when compared to 2005 emissions. Unsatisfied with federal efforts to regulate GHG emissions, some states have moved forward with their own programs. The Regional Greenhouse Gas Initiative ("RGGI"), which took effect in 2009, calls for a 10% reduction in greenhouse gas emissions from 2005 levels by 2018 for the nine participating Northeastern states.[7] Based on the current and projected level of federal activity regarding GHG regulations, PA does not assume a

[5] Given the limited trading anticipated under the CSAPR program, PA does not incorporate specific CSAPR emission allowance prices in dispatch costs in 2015 or beyond.

[6] While EPA regulatory rules regarding GHG emissions will limit coal-fired builds going forward, PA's analysis does not assume incremental coal-fired additions over and above those considered to be 'firm' additions.

[7] The nine Northeastern states participating in RGGI are Connecticut, Delaware, Maryland, Maine, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont. New Jersey withdrew from the program at the end of 2011, however, the New Jersey State Senate passed a resolution in October 2014 that could potentially override the state's withdrawal from RGGI. As such, there is the potential that New Jersey could re-join RGGI in the future, although the resolution (and any impact thereof) still has multiple hurdles to pass before New Jersey could re-join the program. In June 2012, a New Hampshire law went into effect that would withdraw the state from RGGI if two New England states (or 10% of RGGI's New England load) leave the cap-and-trade program.

congressionally-mandated or other federal GHG cap-and-trade (or tax) program within the study period. However, PA does assume RGGI pricing for Rhode Island (as well as the rest of the ISO-NE states). See Table 3.

[redacted]

iv. Supply and demand

The supply and demand balance in power markets is one of the most critical factors in determining power generating asset value, particularly for assets that depend on capacity revenues. See Table 4 for peak demand and energy growth rates for ISO-NE, which are based on the 2015 CELT Load Report through 2024 and use a 5 year average growth rate for the remainder of the study period.

[redacted]

Table 4: Average Annual Growth Rates (2019-2038)[8]

Market	Peak Demand	Energy
ISO-NE	1.2%	1.0%

PA assumes that ISO-NE will have nearly [redacted] GW of supply when PEC enters the market in 2019 (inclusive of PEC) and for the market to be short supply to meet peak demand plus reserve margin in 2024. See Appendix Table A-3 for an overview of PA's supply and demand assumptions.

v. Cost of new entry

The cost of new entry is generally considered as the cost to build new power generation, incorporating financial assumptions such as debt/equity ratio, interest rate on debt, return on equity, etc., in addition to construction costs. It is also referred to as a capital cost. A power market's capital costs help define the premium a market places on capacity, and the overall compensation levels achievable in the market. See Table 5 for the cost of new entry assumptions.

Table 5: 2024 ISO-NE Cost of New Entry (2024$)

[redacted]

iv. Transmission

The New England transmission system has evolved into a well-integrated network. Typical power flows in the area are from north to south and from east to west. With the recent completion of the New England East-West Solution ("NEEWS") transmission upgrades, congestion at nodes on the 345 kV system near Sherman Road has been minimized. For example, over the last 12 months the congestion component of the Rhode Island zone day ahead market price and Ocean State Power's nodal price has been zero for 90 percent of the hours. PA expects these minimal congestion conditions to be maintained over the projection period and expects future prices for the Project to be at a small discount [redacted] to Rhode Island zone prices. PA's analysis of the Project reflects this small discount in energy pricing at the plant's busbar.

[8] Peak demand and load growth numbers through 2024 are from the 2015 CELT Load Report. 2025-2038 uses a 5 year average growth rate.
[9] The installed capital cost represents the long-term cost of new entry, and includes interest during construction.

[redacted]

Market projections

This section provides an overview of the market projections (e.g., market spark spreads and heat rates) for the ISO-NE power market, based on the market assumptions described above.

i. Clean market spark spreads

Clean market spark spreads[10] are a primary indicator of a combined cycle power plant's earnings potential in a wholesale market like ISO-NE. PA's analysis projects on-peak spark spreads in ISO-NE Rhode Island to rise slightly over the study period largely due to increasing natural gas prices. See Figure 4. Occasional dips in clean market spark spreads largely reflect new generation entering the market and depressing power prices. Off-peak spark spreads are projected to remain relatively flat.

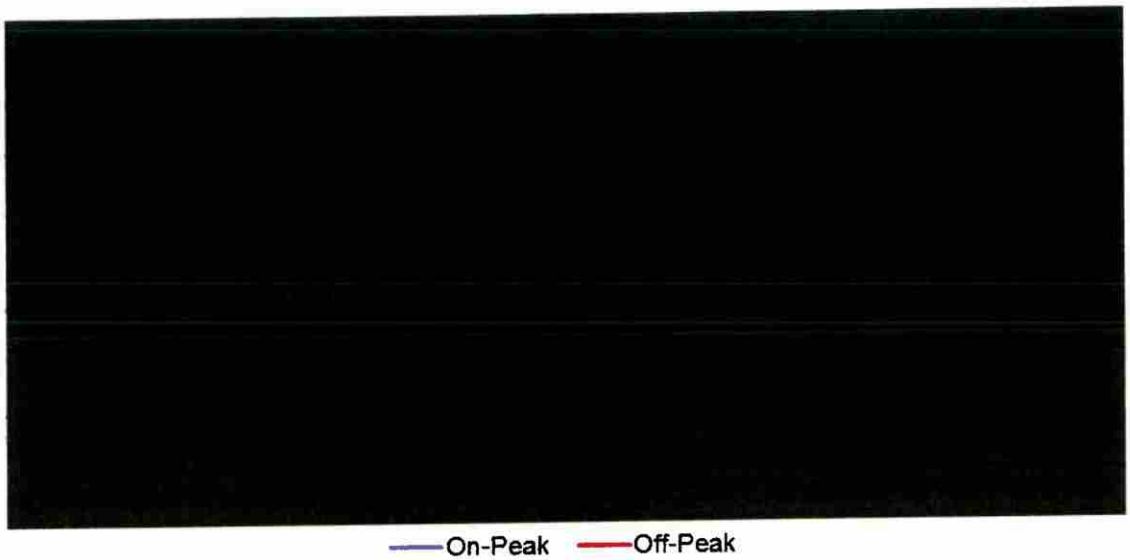
[redacted]

10 [redacted]

[redacted]

ii. Clean market heat rates

On-peak clean market heat rates[12] measure the efficiency of the marginal unit setting power prices in a given region. In ISO-NE, on-peak market heat rates are projected, as shown in Figure 5, to decline from current levels largely driven by more efficient natural gas generation entering the market. Off-peak market heat rates are projected to remain mostly flat.



Asset projections

With a baseload technical summer-rated full load heat rate of [redacted] Btu/kWh, PEC is projected to be one of the most efficient combined cycle power plants in ISO-NE when it comes online in 2019. This is reflected in the Project's capacity factor of [redacted]% in its first full year of operations in 2020, as shown in Figure 6. Capacity factors are projected to decline slightly over the study period to [redacted]% in 2038 due to decreasing market heat rates.

Energy contribution margins (not including capacity revenues, but including ancillary margins[14]) are expected to rise from [redacted] million in 2020 (PEC's first full year of operations) to over $[redacted] million by 2038. The increase in energy margins is driven by improved spark spreads, which is largely driven by increasing natural gas prices (as described in the previous section).

---

[12] [redacted]

[13] Source: PA Consulting Group.

[14] The ancillary services revenues reflected in the pro forma represent ancillary services value incremental to energy margins. Essentially, this means that the projected ancillary 'revenue' is actually ancillary 'margin' that can be earned over and above day-ahead energy market sales. PA's ancillary projections for the Project reflect a combination of regulation and spinning sales.

As noted previously, PA's projections do not include capacity revenues.

[redacted]

[15] 2019 is a partial year (June through December).
[16] Source: PA Consulting Group.

[redacted]

A APPENDIX: PROJECTION AND ASSUMPTION DETAIL

This section provides an overview of PA's market analysis projections, including key input assumptions. All values, unless otherwise noted, are in nominal dollars, based on an inflation rate of 2.2%.

[redacted]

[17] On-peak East Hours [redacted]%
Off-peak East Hours [redacted]%
[18] Source: PA Consulting Group.
[19] Clean spark spreads and market heat rates normalize for the assumed price of CO_2. Clean spark spreads and market heat rates subtract the variable CO_2 cost of a [redacted] Btu/kWh combined cycle.

[redacted]

A.2 Commodity and emission price projections

[redacted]

[redacted] <<< Incorporates forwards as of 4-30-15.
Source: PA Consulting Group.

[redacted]

[22] <<< Incorporates forwards as of 4-30-15.
[23] Source: PA Consulting Group.
[24 a]
[25] Source: PA Consulting Group.

A.4 Firm capacity additions and retirement summary

Table A-4(a): Firm Thermal Capacity Additions – New England[26,27]

[redacted]

Table A-4(b): Firm Retirement Summary – New England[28,29]

[redacted]

[26] If a power generating asset is not online by August 1st of a given year, it does not count towards market reliability until the following year.
[27] Source: PA Consulting Group.
[28] "Retirement Year" corresponds to the year a power generating asset retirement affects the reserve margin referenced in the Supply-Demand tab. If a plant does not retire by August 1st of a given year, it does not impact the Supply-Demand table until the following year.
[29] Source: PA Consulting Group.

[redacted]

A.5 Operating dispatch characteristics

[redacted]

A.6 Contribution margins

Table A-6(a) and A-6(b) provide the details of PA's 15-year projections of PEC's operations and contribution margins. Note that 2019 is a partial year June through December.

[redacted]

[30] Source: Invenergy.
[31] 2019 is a partial year (June through December).

[redacted]

[redacted]

[redacted]

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November 4, 2015

To Whom It May Concern,

At the request of Invenergy LLC ("Invenergy"), Edinaldo Tebaldi and PA Consulting Group ("PA") have prepared this memorandum to isolate the direct economic development impacts resulting from the construction and ongoing operation of the Clear River natural gas-fired combined cycle generation facility.

Figure 1 shows the jobs and income projected to be created by the construction and ongoing operations of Clear River on the State of Rhode Island. The construction of Clear River is projected to generate 382 direct jobs in 2017 and 492 in 2018, and nearly the same number of indirect and induced jobs in those years. The ongoing operation of the facility will create 25 onsite (direct) jobs annually from 2020 through 2034, and 120 more indirect and induced jobs (including the contractors and service professionals involved in the regular operation and maintenance of the facility).

Table 1: Employment and Earnings Impact – Rhode Island Only, 2016-2034

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Direct Employment Impact (FTEs per year)																			
Construction Period	26	388	492	129															
Facility Operations				15	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
Indirect & Induced Employment Impact (FTEs per year)																			
Construction Period	23	346	438	115															
Facility Operations				70	120	120	120	120	120	120	120	120	120	120	120	120	120	120	120
Total Employment Impact	**49**	**734**	**930**	**329**	**145**	**145**	**145**	**145**	**145**	**145**	**145**	**145**	**145**	**145**	**145**	**145**	**145**	**145**	**145**
Direct Earnings Impact ($ - millions)																			
Construction Period	4.5	68.5	88.7	23.9															
Facility Operations				1.0	1.7	1.7	1.8	1.8	1.8	1.9	1.9	2.0	2.0	2.0	2.1	2.1	2.2	2.2	2.3
Indirect & Induced Earnings Impact ($ - millions)																			
Construction Period	1.4	22.2	28.7	7.7															
Facility Operations				5.6	9.8	10.0	10.3	10.5	10.7	11.0	11.2	11.4	11.7	12.0	12.2	12.5	12.8	13.0	13.3
Total Earnings Impact	**5.9**	**90.7**	**117.4**	**38.1**	**11.5**	**11.8**	**12.0**	**12.3**	**12.6**	**12.8**	**13.1**	**13.4**	**13.7**	**14.0**	**14.3**	**14.6**	**14.9**	**15.3**	**15.6**

As part of a supplemental filing to the Energy Facility Siting Board, the Section 5 "Project Benefits" section originally submitted will be adjusted to include this breakdown of direct and indirect impact figures. In addition, in an unrelated adjustment, a statement saying that "Clear River will create an average of more than 400 full-time jobs per year from 2016-2034 in Rhode Island" will be corrected to say "Clear River will create an average of more than 660 full-time jobs per year from 2017-2019 and 145 full-time jobs per year from 2020 to 2034 in Rhode Island."

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TAB 17

ISO New England Installed Capacity Requirement, Local Sourcing Requirements and Capacity Requirement Values for the System-Wide Capacity Demand Curve for the 2018/19 Capacity Commitment Period

ISO New England Inc.
February 2015

ISO New England Installed Capacity Requirement, Local Sourcing Requirements, and Capacity Requirement Values for the System-Wide Capacity Demand Curve for the 2018/19 Capacity Commitment Period

Executive Summary

As part of the Forward Capacity Market (FCM), ISO New England Inc. (ISO-NE) conducts a Forward Capacity Auction (FCA) three years in advance of each Capacity Commitment Period (CCP) to meet the region's resource adequacy needs. The latest FCA, conducted on February 2, 2015, resulted in capacity (megawatts) commitments of sufficient quantities to meet the Installed Capacity Requirement (ICR) for the 2018/19 CCP. The 2018/19 CCP is the ninth CCP of the FCM (FCA9) and it begins on June 1, 2018 and ends on May 31, 2019.

This report documents the assumptions and simulation results of the 2018/19 CCP ICR, Local Sourcing Requirements (LSR) and Capacity Requirement Values for the System–Wide Capacity Demand Curve calculations – (collectively referred to as the "ICR Related Values"), all of which are key inputs in FCA9, along with the Hydro-Québec Interconnection Capability Credits (HQICCs), which are also a key input into the calculation of the ICR.

For the 2018/19 CCP, ISO-NE has identified three Load Zones that are import-constrained and as a result, modeled as Capacity Zones in FCA9. These Capacity Zones are: Connecticut, Northeast Massachusetts/Boston (NEMA/Boston) and the combined Load Zones of Southeastern Massachusetts and Rhode Island (SEMA/RI).[1] Therefore, the ICR Related Values for FCA9 consider three LSR values. The Maine Load Zone, which was modeled as an export-constrained Capacity Zone in prior FCAs, was determined not to be export-constrained. In fact, no Load Zones were considered to be export-constrained. Therefore the ICR Related Values for FCA9 do not consider any Maximum Capacity Limit (MCL) values.

In a filing, dated April 1, 2014, ISO-NE filed Market Rules relating to a System-Wide Capacity Demand Curve (Demand Curve) which was used for the first time in FCA9.[2] The Demand Curve has capacity requirement values which were calculated at the cap and foot[3] of the curve and are considered and filed as part of the ICR Related Values.

---

[1] The FERC filing identifying SEMA/RI as a Capacity Zone is available at: http://www.iso-ne.com/static-assets/documents/regulatory/ferc/filings/2014/may/er14_____000_5_8_14_iso_zone_boundry.pdf.

[2] The filing is available at: http://www.iso-ne.com/static-assets/documents/regulatory/ferc/filings/2014/apr/er14_1639_000_demand_curve_chges_4_1_2014.pdf.

[3] The design of the Demand Curve is specified in Section III.13.2.2. of the Market Rules which describes the cap as the Capacity Requirement Value at 0.200 LOLE, Max[1.6 x Net CONE,CONE] and the foot of the Demand Curve of Capacity Requirement Value at 0.011 LOLE, $0. See Figure 2 for the FCA9 Demand Curve.

As detailed below, ISO-NE has calculated an ICR of 35,142 MW. This value accounts for tie benefits (emergency energy assistance) assumed obtainable from New Brunswick (Maritimes), New York and Québec of 1,970 MW, in aggregate, but it does not reflect a reduction in capacity requirements relating to HQICCs. The HQICC value of 953 MW per month is applied to reduce the portion of the ICR that is allocated to the Interconnection Rights Holders (IHR). Thus, the net amount of capacity to be purchased within the FCA to meet the ICR, after deducting the HQICC value of 953 MW per month, is 34,189 MW.

The LSR values associated with FCA9 for the Connecticut, NEMA/Boston and SEMA/RI Capacity Zones are 7,331 MW, 3,572 MW and 7,479 MW, respectively. As stated previously, there were no export-constrained zones modeled and as such, no MCL values were needed for FCA9.

Section III.12.1 of Market Rule 1 states that the Demand Curve will be calculated using the same methodology as the ICR calculation.

"The ISO shall determine, by applying the same modeling assumptions and methodology used in determining the Installed Capacity Requirement, the capacity requirement value for each LOLE probability specified in Section III.13.2.2 for the System-Wide Capacity Demand Curve."

As such, the capacity requirements at the Demand Curve cap and foot, calculated at a 1 day in 5 years (1-in-5) Loss of Load Expectation (LOLE), and a 1 day in 87 years (1-in-87) LOLE are 33,132 MW and 37,027 MW, respectively.

As in past years, ISO-NE developed the initial ICR recommendation with stakeholder input, which was provided in part through the NEPOOL committee processes through review by NEPOOL's Power Supply Planning Committee (PSPC) during the course of four meetings, by the NEPOOL Reliability Committee (RC) at its September 16, 2014 meeting and by the NEPOOL Participants Committee (PC) at its October 3, 2014 meeting.[4] In addition, the New England States Committee on Electricity (NESCOE) provided feedback on the proposed ICR Related Values at the relevant NEPOOL committee meetings. Representatives of NESCOE provided feedback at discussions of the ICR Related Values assumptions at the PSPC and were in attendance for the RC and PC meetings at which the ICR Related Values for FCA9 were discussed and voted.

After the NEPOOL committee voting process was completed, ISO-NE filed the ICR Related Values and HQICCs for the 2018/19 FCA with the FERC in a filing dated

[4] All of the load and resource assumptions needed for the General Electric Multi-Area Simulation ("GE MARS") model used to calculate tie benefits and the ICR Related Values were reviewed by the PSPC, a subcommittee of the NEPOOL Reliability Committee (RC). The NEPOOL Load Forecast Committee (LFC), also a subcommittee of the NEPOOL Reliability Committee, reviews the load forecast assumptions and methodology.

November 4, 2014.[5] The FERC accepted the ICR Related Values in a letter dated January 2, 2015.[6]

Table 1 shows the ICR Related Values for the 2018/19 CCP. The monthly values for the HQICCs are provided in Table 2.

Table 1: Summary of 2018/19 ICR Related Values (MW)[7,8]

2018/19 FCA	New England	Connecticut	NEMA/ Boston	SEMA/RI
Peak Load (50/50)	30,005	7,725	6,350	5,910
Existing Capacity Resources	32,842	9,239	3,868	6,984
Installed Capacity Requirement	35,142			
NET ICR (ICR Minus 953 MW HQICCs)	34,189			
Capacity Requirement at 1-in-5 LOLE	33,132			
Capacity Requirement at 1-in-87 LOLE	37,027			
Local Sourcing Requirements		7,331	3,572	7,479

Table 2: Monthly HQICCs (MW)

2018/19 CCP Month	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19
HQICC Values	953	953	953	953	953	953	953	953	953	953	953	953

[5] The ISO-NE filing is located at http://www.iso-ne.com/static-assets/documents/2014/11/er15-___-000_11-6-14_2018-2019_icr_filing.pdf.

[6] The FERC Order accepting the ICR Values for the 2018/19 FCA is available at: http://www.iso-ne.com/static-assets/documents/2015/01/er15-325-000_1-2-15_order_accept_2018-2019_icrs.pdf.

[7] After reflecting a reduction in capacity requirements relating to the 953 MW of HQICCs that are allocated to the Interconnection Rights Holders (IHR), the net amount of capacity to be procured within the Forward Capacity Auction to meet the ICR is the Net ICR value of 34,189 MW.

[8] Existing Capacity Resource value for New England excludes HQICCs.

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Introduction

The Installed Capacity Requirement (ICR) is a measure of the installed resources that are projected to be necessary to meet both ISO New England's (ISO-NE) and the Northeast Power Coordination Council's (NPCC) reliability standards[9], with respect to satisfying the peak demand forecast for the New England Balancing Authority area while maintaining required reserve capacity. More specifically, the ICR is the amount of resources (MWs) needed to meet the reliability requirements defined for the New England Balancing Authority area of disconnecting non-interruptible customers (a loss of load expectation or "LOLE"), on average, no more than once every ten years (an LOLE of 0.1 days per year). This criterion takes into account: other possible levels of peak electric loads due to weather variations, the impacts of resource availability, and the potential load and capacity relief obtainable through the use of ISO New England Operating Procedure No. 4 – *Actions During a Capacity Deficiency* (OP-4).[10]

This report discusses the derivation of the ICR, Local Sourcing Requirements (LSR) and the capacity requirement values for the System-Wide Capacity Demand Curve ("Demand Curve") (collectively, the "ICR Related Values")[11], along with the Hydro-Québec Interconnection Capability Credits (HQICCs) for the 2018/19 CCP's Forward Capacity Auction (FCA) conducted on February 2, 2015. The 2018/19 CCP starts on June 1, 2018 and ends on May 31, 2019.

This report documents the general process and methodology used for developing the assumptions utilized in calculating the ICR, including assumptions about load, resource capacity values and availability, load relief from OP-4, and transmission interface transfer capabilities and the methodology used for calculating the ICR. Also discussed are the calculation of LSR for import-constrained Load Zones, including the Local Resource Adequacy (LRA) Requirements and Transmission Security Analysis (TSA) Requirements that are inputs into the calculation of LSR along with the calculation of the MCL for export-constrained Capacity Zones which were not required as part of FCA9. In general, the methodology used for calculating the ICR Related Values for the 2018/19 FCA remains unchanged from the methodology used for calculating the prior ICR Related Values for the 2017/18 FCA, with the exception of the additional calculation of the capacity requirements for the Demand Curve, which was used for the first time in FCA9.

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[9] Information on the NPCC Standards is available at: https://www.npcc.org/Standards/default.aspx.

[10] ISO-NE OP-4 is located at: http://www.iso-ne.com/static-assets/documents/rules_proceds/operating/isone/op4/op4_rto_final.pdf.

[11] For FCA9, no zones were determined to be export-constrained and therefore, no Maximum Capacity Limit (MCL) values were filed as part of FCA9.

Summary of ICR Related Values and Components for 2018/19

Table 3 documents the ICR Related Values and components relating to the calculation of ICR.

Table 3: ICR Related Values and Components for 2018/19 (MW)[12]

2018/19 FCA	New England	Connecticut	NEMA/ Boston	SEMA/RI
Peak Load (50/50)	30,005	7,725	6,350	5,910
Existing Capacity Resources	32,842	9,239	3,868	6,984
Installed Capacity Requirement	35,142			
NET ICR (ICR Minus 953 MW HQICCs)	34,189			
Capacity Requirement at 1-in-5 LOLE	33,132			
Capacity Requirement at 1-in-87 LOLE	37,027			
Local Sourcing Requirements		7,331	3,572	7,479

The 35,142 MW ICR value does not reflect a reduction in capacity requirements relating to HQICCs that are allocated to the Interconnection Rights Holders (IRH) in accordance with Section III.12.9.2 of Market Rule 1. After deducting the monthly HQICC value of 953 MW, the net Installed Capacity Requirement for use in the 2018/19 FCA is 34,189 MW, which is described as the "*Net ICR*".

The 34,189 MW of Net ICR, which excludes HQICCs, results in an Annual Resulting Reserve Margin value of 13.9%. The Annual Resulting Reserve Margin is a measure of the amount of resources potentially available in excess of the 50/50 seasonal peak load forecast value and is calculated as:

Figure 1: Formula for Annual Resulting Reserve Margin (%)

Annual Resulting Reserve Margin (%) =
((ICR-HQICCs-Annual 50/50 Peak Load) / (Annual 50/50 Peak Load)) x 100

The 13.9% Annual Resulting Reserving Margin is a slight increase from the 13.6% value calculated for the 2017/18 FCA. While some changes in ICR assumptions decreased the reserve margin, some do cause it to increase, particularly assumptions related to an increase in the generator forced outage rates. Overall, the net change in reserve margin was small. The increase in generator unavailability and other changes, along with the

[12] Existing Capacity Resource value for New England excludes HQICCs.

overall change in ICR, is discussed in more detail in the last section of this report, *Difference from the 2017/18 FCA ICR Related Values.*

The capacity requirement values for the Demand Curve, calculated for the first time for FCA9 require that:

"*The ISO shall determine, by applying the same modeling assumptions and methodology used in determining the Installed Capacity Requirement, the capacity requirement value for each LOLE probability specified in Section III.13.2.2 for the System-Wide Capacity Demand Curve*"

according to Section III.12.1 of Market Rule 1.

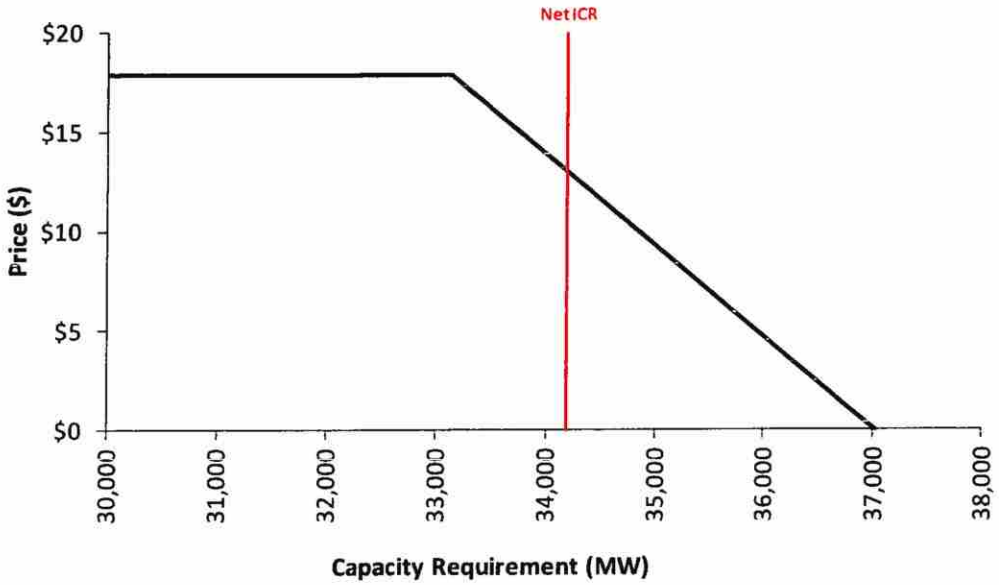
As such, the capacity requirement values at the Demand Curve cap and foot, calculated at 1 day in 5 years (1-in-5) Loss of Load Expectation (LOLE), and at 1 day in 87 years (1-in-87) LOLE are 33,132 MW and 37,027 MW, respectively.

The coordinates of the Demand Curve use a price quantity for the Cost of New Entry (CONE) into the capacity market. This price quantity is determined as max [1.6 times Net CONE, CONE]. CONE for the FCA for the 2018/19 CCP is $14.04/kW-month while Net CONE is $11.08/kW-month.[13]

Using the coordinates of the cap of the Demand Curve of [Capacity Requirement Value at 1-in-5 LOLE, 1.6 x Net CONE ($17.728] and the foot of the Demand Curve of [Capacity Requirement Value at 1-in-87 LOLE, $0], the Demand Curve for FCA9 is shown in Figure 2.

[13] The determination of CONE for 2018/19 was discussed at the March 12, 2014 Markets Committee: http://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2014/mar12132014/a02a_the_brattle_group_demand_curve_net_cone_final_proposal_03_12_14.pptx. For rules relating to CONE, see Market Rule 1 III.13.2.4.

Figure 2: System-Wide Capacity Demand Curve for 2018/19 (FCA9)



A summary of historical ICR Related Values, including links to documentation and filings for FCA9 and prior years are available on the ISO-NE website under System Planning > Installed Capacity Requirements > Summary of Historical ICR Values (EXCEL Spreadsheet) and can be directly accessed at this link: http://www.iso-ne.com/static-assets/documents/2014/12/summary_of_icr_values_expanded.xlsx.

Stakeholder Process

As in past years, ISO-NE developed the initial ICR recommendation with stakeholder input, which was provided in part through the NEPOOL committee process with review by NEPOOL's Power Supply Planning Committee (PSPC) during the course of four meetings. The PSPC, which is chaired by ISO-NE, is a non-voting, technical subcommittee reporting to the NEPOOL Reliability Committee (RC). Most PSPC members are representatives of NEPOOL Participants. The PSPC assists ISO-NE with the development of resource adequacy based requirements such as the ICR, LSR, MCL and Demand Curve capacity requirements, including the appropriate load and resource assumptions for modeling expected power system conditions.

As part of the stakeholder voting process, the ICR Related Values was vetted through the RC at its September 16, 2014 meeting and acted on by the NEPOOL Participants Committee (PC) at its October 3, 2014 meeting.[14] Representatives of the New England States Committee on Electricity ("NESCOE") provided feedback on the proposed ICR Related Values at the relevant NEPOOL PSPC, RC and PC meetings, and were in attendance for the meetings at which the ICR Related Values for the 2018/19 Forward Capacity Auction were discussed and voted.

At the September 16, 2014 meeting of the RC, a motion to recommend support of the ICR Related Values passed by a show of hands, with four opposed (1 Transmission Sector, 1 Publicly Owned Sector, and 2 Supplier Sector) and one abstention (1 Transmission Sector). A motion that the RC recommend that the PC support the HQICC values passed by a show of hands, with two opposed (2 Supplier Sector) and one abstention (1 Supplier Sector).

At the October 3, 2014 PC meeting, the ICR Related Values and HQICC Values were removed as part of the Consent Agenda due to concerns by some Stakeholders that ISO-NE *"failed to recognize a present and continuing investment in renewable distributed generation resources."*[15] Specifically they believed the load forecast, as an input into the ICR Related Values, should be decreased by an appropriate forecast of photovoltaic resources in the 2018/19 CCP. The vote on ICR Related Values subsequently failed at the PC.[16]

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[14] All of the load and resource assumptions needed for the General Electric Multi-Area Simulation (GE MARS) model used to calculate tie benefits and the ICR Related Values were reviewed by the PSPC, a subcommittee of the NEPOOL RC. The NEPOOL Load Forecast Committee (LFC), also a subcommittee of the NEPOOL RC, reviews the load forecast assumptions and methodology.

[15] The memo is part of the October 3, 2014 PC Meeting materials at http://www.iso-ne.com/static-assets/documents/2014/10/NPC_20141003_Addl.pdf.

[16] At the PC, the vote on the FCA9 ICR Related Values failed with a 38.61% vote in favor (Generation – 17.17%, Transmission – 0%; Supplier – 15.60%; Alternative Resources – 4.28%; Publicly Owned Entity – 0%; and End User – 1.56%).

ISO-NE filed the ICR Related Values and HQICCs for the 2018/19 FCA with the FERC on November 4, 2014.[17] The FERC accepted the ICR Related Values in a letter dated January 2, 2015.[18]

[17] A copy of the filing is available at: http://www.iso-ne.com/static-assets/documents/2014/11/er15-___-000_11-6-14_2018-2019_icr_filing.pdf.

[18] The FERC Order accepting the ICR Values for the 2018/19 FCA is available at: http://www.iso-ne.com/static-assets/documents/2015/01/er15-325-000_1-2-15_order_accept_2018-2019_icrs.pdf.

Methodology

Reliability Planning Model for ICR Related Values

The ICR is the minimum level of capacity required to meet the reliability requirements defined for the New England Balancing Authority area. This requirement is documented in Section 2 of ISO New England Planning Procedure No. 3,[19] *Reliability Standards for the New England Area Bulk Power Supply System*, which states:

> *"Resources will be planned and installed in such a manner that, after due allowance for the factors enumerated below, the probability of disconnecting non-interruptible customers due to resource deficiency, on the average, will be no more than once in ten years. Compliance with this criterion shall be evaluated probabilistically, such that the loss of load expectation (LOLE) of disconnecting non-interruptible customers due to resource deficiencies shall be, on average, no more than 0.1 day per year."*

Included as variables within the reliability model are:

a. The possibility that load forecasts may be exceeded as a result of weather variations.
b. Immature and mature equivalent forced outage rates appropriate for resources of various sizes and types, recognizing partial and full outages.
c. Due allowance for generating unit scheduled outages and deratings.
d. Seasonal adjustments of resource capability.
e. Proper maintenance requirements.
f. Available operating procedures.
g. The reliability benefits of interconnections with systems that are not Governance Participants.
h. Such other factors as may be appropriate from time to time.

The ICR for the 2018/19 CCP was established using the General Electric Multi-Area Reliability Simulation Model (GE MARS). GE MARS is a computer program that uses a sequential Monte Carlo simulation to probabilistically compute the resource adequacy of a bulk electric power system by simulating the random behavior of both loads and resources. For the ICR calculation, the GE MARS model is used as a one-bus model and the New England transmission system is assumed to have no constraints within this simulation. In other words, all the resources modeled are assumed to be able to deliver their full output to meet forecast load requirements.

To calculate the expected days per year that the bulk electric system would not have adequate resources to meet peak demands and required reserves, the GE MARS Monte Carlo process repeatedly simulates the year using multiple replications and evaluates the impacts of a wide-range of possible random combinations of resource outages.

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[19] Available at: http://www.iso-ne.com/static-assets/documents/rules_proceds/isone_plan/pp03/pp3_final.pdf.

Chronological system histories are developed by combining randomly generated operating histories of the resources serving the hourly chronological demand. For each hour, the program computes the isolated area margins based on the available capacity and demand within each area. The program collects the statistics for computing the reliability indices and then proceeds to the next hour to perform the same type of calculation. After simulating all of the hours in the year, the program computes the annual indices and tests for convergence. If the simulation has not converged to an acceptable level, it proceeds to another replication of the study year.

Installed Capacity Requirement (ICR) Calculation

The formula for calculating the New England ICR is:

Figure 3: Formula for ICR Calculation

$$Installed\ Capacity\ Requirement\ (ICR) = \frac{Capacity - Tie\ Benefits - OP4\ Load\ Relief}{1 + \frac{ALCC}{APk}} + HQICCs$$

Where:	APk	= Annual 50/50 Peak Load Forecast for summer
	Capacity	= Total Capacity (sum of all supply and demand resources)
	Tie Benefits	= Tie Reliability Benefits
	OP-4 Load Relief	= Load relief from ISO-NE OP-4 - Actions 6 & 8 and the modeling of the minimum 200 MW Operating Reserve limit
	ALCC	= Additional Load Carrying Capability (as determined by the % of peak load)
	HQICCs	= Monthly HQICC value[20]

The ICR formula is designed such that the results identify the minimum amount of capacity required to meet New England's resource adequacy criterion of expecting to interrupt non-interruptible load, on average, no more than once every ten years. If the system is more reliable than the resource adequacy criterion (i.e., the system LOLE is less than or equal to 0.1 days per year), additional resources are not required, and the ICR is determined by increasing loads (*Additional Load Carrying Capability* or ALCC) so that New England's LOLE is exactly at 0.1 days per year. For the 2018/19 CCP, the New England system, using the resources that qualified as Existing Capacity, is less reliable than the resource adequacy criterion requirement. Therefore, additional capacity in the form of proxy units is needed within the model. Proxy units are used if existing capacity resources are insufficient to meet the resource adequacy planning criterion, as provided by Section III.12.7.1 of Market Rule 1. Proxy units are assigned availability characteristics such that when proxy resources are used in place of all the resources assumed to be available to the system, the resulting system LOLE remains unchanged from that calculated using the existing resources. The use of proxy units to meet the

[20] In the ICR calculation, the HQICCs are treated differently than other resources; they are not adjusted by the ALCC amount.

system LOLE criterion is intended to neutralize the size and availability impact of unknown resource additions on the ICR.

Prior to the calculation of ICR Related Values for the 2018/19 CCP, ISO-NE conducted a study to update the size and availability characteristics of the proxy units used in the analysis.[21] In the study, proxy unit characteristics are determined using the average system availability and a series of LOLE calculations. Using these characteristics gives a proxy unit that when added to the model, does not increase or decrease ICR. For more details on the proxy unit characteristics, see the section of this report entitled "*Proxy Units.*"

To determine the ICR for the 2018/19 CCP, four proxy units were needed in addition to the existing capacity within the ICR model. In addition, for the 1-in-5 LOLE and the 1-in-87 LOLE capacity requirements calculations for the Demand Curve, one proxy unit was needed and14 proxy units were needed, respectively.

Table 4 shows the details of the variables used to calculate the ICR for the 2018/19 CCP.

Table 4: Variables Used to Calculate ICR and Demand Curve (MW)

Total Capacity Breakdown	1-in-5 LOLE	2018/19 FCA ICR	1-in-87 LOLE
Generating Resources	29,829	29,829	29,829
Tie Benefits	1,970	1,970	1,970
Imports/Sales	(41)	(41)	(41)
Demand Resources	3,054	3,054	3,054
OP4 - Action 6 & 8 (Voltage Reduction)	441	441	441
Minimum Reserve Requirement	(200)	(200)	(200)
Proxy Unit Capacity	400	1,600	4,400
Total Capacity	**35,453**	**36,653**	**39,453**

Installed Capacity Requirement Calculation Details	1-in-5 LOLE	2018/19 FCA ICR	1-in-87 LOLE
Annual Peak	30,005	30,005	30,005
Total Capacity	35,453	36,653	39,453
Tie Benefits	1,970	1,970	1,970
HQICCs	953	953	953
OP4 - Action 6 & 8 (Voltage Reduction)	441	441	441
Minimum Reserve Requirement	(200)	(200)	(200)
ALCC	99	222	175
Installed Capacity Requirements	**34,085**	**35,142**	**37,980**
Net ICR	**33,132**	**34,189**	**37,027**
Reserve Margin without HQICCs	10.4%	13.9%	23.4%

Local Sourcing Requirements (LSR) Calculation

The methodology for calculating LSR for import-constrained Capacity Zones involves calculating the amount of resources located within the Capacity Zone that would meet

[21] Study results presented at the May 22, 2014 PSPC Meeting: http://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/relblty_comm/pwrsuppln_comm/mtrls/2014/may222014/proxy_unit_2014_study.pdf.

both a local criterion requirement called the Local Resource Adequacy (LRA) Requirement and a transmission security criterion called the Transmission Security Analysis (TSA) Requirement. The TSA Requirement is an analysis that ISO-NE uses to maintain operational reliability when reviewing de-list bids of resources within the FCM auctions. The system must meet both resource adequacy and transmission security requirements; therefore, the LSR for an import-constrained zone is the amount of capacity needed to satisfy *"the higher of"* either (i) the LRA or (ii) the TSA Requirement.

Local Resource Adequacy (LRA) Requirement

The LRA Requirements are calculated using the same assumptions for forecasted load and resources as those used within the calculation of the ICR. To determine the locational requirements of the system, the LRA Requirements are calculated using the multi-area reliability model, GE MARS, according to the methodology specified in Section III.12.2 of Market Rule 1.

The LRA Requirements are calculated using the value of the firm load adjustments and the existing resources within the zone, including any proxy units that were added as a result of the total system not meeting the LOLE criteria. Because the LRA Requirement is the minimum amount of resources that must be located within a zone to meet the system reliability requirements, for a zone with excess capacity, the process to calculate this value involves shifting capacity out of the zone under study until the reliability threshold, or target LOLE, is achieved. Shifting capacity, however, may lead to skewed results, since the load carrying capability of various resources are not homogeneous. For example, one megawatt of capacity from a nuclear power plant does not necessarily have the same load carrying capability as one megawatt of capacity from a wind turbine. Consequently, in order to model the effect of shifting "generic" capacity, firm load is shifted. Specifically, as one megawatt of load is added to an import-constrained zone, a megawatt of load is subtracted from the rest of New England, thus keeping the entire system load constant. The load that was shifted must be subtracted from the total resources (including proxy units) to determine the minimum amount of resources that are required in that zone. Before the shifted load is subtracted, it is first converted to equivalent capacity by using the average resource-unavailability rate within the zone. Thus, the LRA Requirement is calculated as the existing resources in the zone including any proxy units, minus the unavailability-adjusted firm load adjustment.

As this load shift test is being performed over a transmission interface internal to the New England Balancing Authority Area, an allowance for transmission-related LOLE must also be applied. This transmission-related LOLE allowance is 0.005 days per year and is only applied when determining the LRA Requirement of a Capacity Zone. An LOLE of 0.105 days per year is the point at which it becomes clear that the remaining resources within the zone under study are becoming insufficient to satisfy local capacity requirements. Further reduction in local resources would cause the LOLE in New England to rapidly increase above the criterion.

For each import-constrained transmission Capacity Zone, the LRA Requirement is calculated using the following methodology, as outlined in Market Rule 1, Section III.12.2.1:

a) Model the Capacity Zone under study and the *Rest of New England* area using the GE MARS simulation model, reflecting load and resources (supply & demand-side) electrically connected to them, including external Balancing Authority area support from tie benefits.

b) If the system LOLE is less than 0.1 days/year, firm load is added (or unforced capacity is subtracted) so that the system LOLE equals 0.1 days/year.

c) Model the transmission interface constraint between the Load Zone under study and the *Rest of New England.*

d) Add proxy units, if required, within the ISO-NE Balancing Authority Area to meet the resource adequacy planning criterion of once in 10 year disconnection of non-interruptible customers. If the system LOLE with proxy units added is less than 0.1 days/year, firm load is added (or unforced capacity is subtracted) so that the system LOLE equals 0.1 days/year. Proxy units are modeled as stated in Section III.12.7.1 of Market Rule 1.

e) Adjust the firm load within the Capacity Zone under study until the LOLE of the ISO-NE Balancing Authority Area reaches 0.105 days per year LOLE. As firm load is added to (or subtracted from) the Capacity Zone under study, an equal amount of firm load is removed from (or added to) the *Rest of New England.*

The LRA Requirement is then calculated using the formula:

Figure 4: Formula for LRA Calculation

$$LRA_Z = Resources_Z + Proxy\ Units_Z - \left(\frac{Firm\ Load\ Adjustment_Z}{1-FOR_Z}\right)$$

Where	LRA_z	= Local Resource Adequacy Requirement for Capacity Zone Z.
	$Resources_z$	= MW of resources (supply & demand-side) electrically located within Load Zone Z, including Import Capacity Resources on the import-constrained side of the interface, if any and excludes HQICCs.
	$Proxy\ Units_z$	= MW of proxy unit additions, if needed, in Capacity Zone Z.
	$Firm\ Load\ Adjustment_z$	= MW of firm load added within Capacity Zone Z to make the LOLE of the New England Balancing Authority area equal to 0.105 days per year.
	FOR_z	= Capacity weighted average of the forced outage rate modeled for all resources (supply & demand-side) within Capacity Zone Z, including any proxy unit additions to Capacity Zone Z.

In addition, when performing the LRA calculation for the *Rest of New England* area used in the calculation of local requirements for export-constrained zones, the surplus capacity adjustment used to bring the system to the 0.1 days per year reliability criterion is also included in the calculation as:

Figure 5: Surplus Capacity Adjustment in *Rest of New England*

$$-\left(\frac{Surplus\ Capacity\ Adjustment_Z}{1-FOR_Z}\right)$$

Where:

$Surplus\ Capacity\ Adjustment_z$ = MW of firm load added within Zone Z to make the LOLE of the New England Balancing Authority area equal to 0.1 days per year

Table 5 shows the details of the LRA Requirement calculation for the 2018/19 CCP.

Table 5: LRA Requirement Calculation Details (MW)

		Connecticut	NEMA/Boston	SEMA/RI
$Resource_z$	[1]	9,239	3,868	6,984
$Proxy\ Units_z$	[2]	0	0	800
$Firm\ Load\ Adjustment_z$	[4]	1,825	775	278
FOR_z	[5]	0.074	0.042	0.090
LRA_z	[5]=[1]+[2]-([3]/(1-[4]))	**7,268**	**3,129**	**7,479**

Transmission Security Analysis (TSA) Calculation

The TSA is a deterministic reliability screen of a transmission import-constrained area and is a security review as defined within Section 3 of ISO New England Planning Procedure No. 3, *Reliability Standards for the New England Area Bulk Power Supply System* and within Section 5.4 of Northeast Power Coordinating Council's (NPCC)

Regional Reliability Reference Directory #1, *Design and Operation of the Bulk Power System.*[22] The TSA review determines the requirements of the sub-area in order to meet its load through internal generation and import capacity. It is performed via a series of discrete transmission load flow study scenarios. In performing the analysis, static transmission interface transfer limits are established as a reasonable representation of the transmission system's capability to serve sub-area demand with available existing resources. The results are then presented in the form of a deterministic operable capacity analysis.

In accordance with ISO New England Planning Procedure No. 3 and NPCC's Regional Reliability Reference Directory #1, the TSA includes evaluations of both: (1) the loss of the most critical transmission element and the most critical generator (Line-Gen), and (2) the loss of the most critical transmission element followed by loss of the next most critical transmission element (Line-Line). These deterministic analyses are currently used each day by ISO-NE System Operations to assess the amount of capacity required to be committed day-ahead within import-constrained Capacity Zones. Further, such deterministic sub-area transmission security analyses have consistently been used for reliability review studies performed to determine whether a resource seeking to retire or de-list would cause a violation of the reliability criteria.

Figure 6 shows the formula used in the calculation of TSA requirements.

Figure 6: Formula for TSA Requirements

$$\text{TSA Requirement} = \frac{(\text{Need} - \text{Import Limit})}{1 - (\text{Assumed Unavailable Capacity} / \text{Existing Resources})}$$

Where:

Need =	Load + Loss of Generator ("Line-Gen" scenario), or Load + Loss of Import Capability (going from an N-1 Import Capability to an N-1-1 Import Capability; "Line-Line" scenario)
Import Limit =	Assumed transmission import limit
Assumed Unavailable Capacity =	Amount of assumed resource unavailability applied by de-rating capacity
Existing Resources =	Amount of Existing Capacity Resources within the Zone

Methodology for Calculating the TSA

The system conditions used for the TSA analysis within the FCM are documented in Section 6 of ISO New England Planning Procedure No. 10, *Planning Procedure to Support the Forward Capacity Market.*[23] For the calculation of ICR, LRA and TSA, the bulk of the assumptions are the same. However, due to the deterministic and

[22] A copy can be found at https://www.npcc.org/Standards/Directories/Directory%201%20-%20Design%20and%20Operation%20of%20the%20Bulk%20Power%20System%20%20Clean%20April%2020%202012%20GJD.pdf.

[23] Available at: http://www.iso-ne.com/rules_proceds/isone_plan/.

transmission security-oriented nature of the TSA, some of the assumptions for calculating the TSA requirement differ from the assumptions used in determining the LRA Requirement. The differences are as follows: the assumed loads for the TSA are the 90/10 peak loads for the Connecticut, Boston and combined SEMA and Rhode Island sub-areas[24] for the 2018/19 CCP, whereas for LRA calculations, a distribution of loads covering the range of possible peak loads for that CCP is used. In addition, for the TSA, the forced outage of fast-start (peaking) generation is based on an assumed value of 20% instead of being based on historical five-year average generating unit performance. Finally, the load and capacity relief obtainable from actions of ISO-NE OP-4, with the exception of Demand Resources (which are treated as capacity resources), is not assumed within TSA calculations.

Table 5 shows the details of the TSA requirement calculation for the Connecticut, NEMA/Boston, and SEMA/RI Capacity Zones.

Table 6: TSA Calculation Details (MW)

	Connecticut	NEMA/Boston	SEMA/RI
2014 Sub-area 90/10 Load*	8,415	6,835	6,465
Reserves (Largest unit or loss of import capability)	1,225	1,412	700
Sub-area Transmission Security Need	**9,640**	**8,247**	**7,165**
Sub-area Existing Resources	9,239	3,868	6,984
Assumed Unavailable Capacity	-808	-190	-723
Sub-area N-1 Import Limit	2,950	4,850	786
Sub-area Available Resources	**11,381**	**8,528**	**7,047**

TSA Requirement = (9640-2950)/(1-808/9239) (8247-4850)/(1-190/3868) (7165-786)/(1-723/6984)

=7,331 **=3,572** **=7,116**

Local Sourcing Requirement (LSR)

The LSR is determined as the higher of the LRA Requirement or TSA Requirement for the respective Capacity Zone. Table 7 summarizes the LRA and TSA for the Connecticut, NEMA/Boston and SEMA/RI Capacity Zones. As shown, the LRA is the highest requirement for the SEMA/RI Capacity Zone while the TSA is the highest requirement for the Connecticut and NEMA/Boston Capacity Zones. Therefore, the LSR for the Connecticut, NEMA/Boston and SEMA/RI Capacity Zones are 7,331 MW, 3,572 MW and 7,479 MW, respectively.

[24] The combined Connecticut, Southwest Connecticut and Norwalk sub-areas, the Boston sub-area, and the combined Southeastern Massachusetts and Rhode Island sub-area load forecast and resources are used as proxies for the Connecticut, NEMA/Boston and SEMA/RI Capacity Zones load forecast and resources since the transmission transfer capability of the interfaces used in the respective LSR calculations are determined based on the 13 sub-area system representations used within ISO-NE's Regional System Plan (RSP).

Table 7: LSR for the 2018/19 CCP (MW)

Capacity Zone	Transmission Security Analysis Requirements	Local Resource Adequacy Requirements	Local Sourcing Requirements
Connecticut	7,331	7,268	7,331
NEMA/Boston	3,572	3,129	3,572
SEMA/RI	7,116	7,479	7,479

Maximum Capacity Limit (MCL) Calculation

For the 2018/19 CCP, no zones were considered to be export-constrained; therefore an MCL was not filed for any Capacity Zones. An indicative MCL was calculated for the Maine Load Zone as part of the Capacity Zone Trigger Analysis, which determines if a Load Zone is either import or export-constrained and therefore modeled as a Capacity Zone in an FCA. This section of the Report details the calculation of the indicative MCL for the Maine Load Zone for the 2018/19 CCP.

To determine the MCL, the New England ICR and the LRA for the Rest of New England need to be identified. Given that the ICR is the total amount of resources that need to be procured within New England, and the LRA requirement for the Rest of New England is the minimum amount of resources required for that area to satisfy its reliability criterion; the difference between the two is the maximum amount of resources that can be purchased within an export-constrained Load Zone.

The indicative MCL for Maine includes qualified capacity resource imports over the New Brunswick ties (if relevant for a particular CCP) and also reflects the tie benefits assumed available over the New Brunswick ties. That is, the MCL is reduced to reflect the energy flows required to receive the assumed tie benefits from the Maritimes to assist the ISO-NE Balancing Authority Area at a time of a capacity shortage. Allowing more purchases of capacity from resources located in Maine could preclude the energy flows required to realize tie benefits.

For an export-constrained transmission Capacity Zone, the MCL is calculated using the following method as described in Market Rule 1, Section III.12.2.2:

a) Model the Capacity Zone under study and the *Rest of New England* area using the GE MARS simulation model, reflecting load and resources (supply & demand-side) electrically connected to them, including external Balancing Authority area support from tie benefits.

b) If the system LOLE is less than 0.1 days/year, firm load is added (or unforced capacity is subtracted) so that the system LOLE equals 0.1 days/year.

c) Model the transmission interface constraint between the Capacity Zone under study and the *Rest of New England* area.

d) Add proxy units, if required, within the ISO-NE Balancing Authority Area to meet the resource adequacy planning criterion of once in 10 years of disconnection of non-interruptible customers. If the system LOLE with proxy units added is less than 0.1 days/year, firm load is added (or unforced capacity is subtracted) so that the system LOLE equals 0.1 days/year.

e) Adjust the firm load within the *Rest of New England* area until the LOLE of the *Rest of New England* area reaches 0.105 days per year LOLE. As firm load is added to (or subtracted from) the *Rest of New England* area, an equal amount of firm load is removed from (or added to) the Capacity Zone under study.

The MCL is then calculated using the formula:

Figure 7: Formula for MCL Calculation

$$MCL_Y = Net\ ICR - LRA_{Rest\ of\ New\ England}$$

Where MCL_Y = Maximum Capacity Limit for Load Zone Y

Net ICR = MW of Net ICR

$LRA_{Rest\ of\ New\ England}$ = MW of Local Resource Adequacy Requirement for the *Rest of New England* area, which for the purposes of this calculation is treated as an import-constrained region, determined in accordance with Market Rule 1, Section III.12.2.1

Table 8 shows the details of the indicative MCL for the Maine Load Zone calculation for the 2018/19 CCP. This value was not filed with the FERC as part of the ICR Related Values as Maine was not determined to be a Capacity Zone.

Table 8: Indicative MCL for the Maine Load Zone Calculation Details (MW)

		2018/19 FCA
ICR for New England	[1]	34,189
$LRA_{RestofNewEngland}$	[2]	30,275
Maximum Capacity $Limit_Y$	[3]=[1]-[2]	**3,913**

Assumptions

Load Forecast

For each state in New England, ISO-NE develops a forecast distribution of typical daily peak loads for each week of the year based on each week's historical weather distribution combined with an econometrically estimated monthly model of typical daily peak demands. Each weekly distribution of typical daily peak demands includes the full range of daily peaks that could occur over the full range of weather experienced within that week along with their associated probabilities.

The load forecast models for each of the six New England states were estimated using thirteen years of historical weekday daily peaks, the weather conditions at the time of the daily peak, a seasonal relationship that captures the change in peak demand response to weather over time, and a seasonal relationship that captures the change in peak demand response to base energy demand (and therefore economic and demographic factors) over time. The weather response relationships are forecast to grow at their historical rates but are adjusted for expected changes in electric appliance saturations. The base load relationships are forecasted to grow at the same rate as the associated energy forecast. The weather is represented by over forty years of historically-based weekly regional weather. The energy forecast for each state is econometrically estimated using forecasts of the real price of electricity and either real income or real gross state product.

For purposes of determining the load forecast, ISO-NE Balancing Authority Area's load is defined as the sum of the load of each of the six New England states, calculated as described above. The forecasted load for the Connecticut Capacity Zone is the forecasted load for the state of Connecticut. The forecasted load for the NEMA/Boston Capacity Zone is developed using a load share ratio of the NEMA/Boston load to the forecasted load for the entire state of Massachusetts. The load share ratio is based on detailed bus load data from the network model for NEMA/Boston, as compared to the entire state of Massachusetts. The forecasted load for the SEMA portion of the SEMA/RI Capacity Zone is developed using the same load share ratio methodology as NEMA/Boston, while the RI portion is the load forecast for the state of Rhode Island.

The overall New England and individual sub-area load forecasts used in the calculation of ICR Related Values for the 2018/19 CCP are documented within the *2014 Forecast Report of Capacity, Energy, Loads and Transmission (CELT Report)*.[25]

Load Forecast Uncertainty

GE MARS models the load forecast using hourly chronological sub-area loads and can include the effects of load forecast uncertainty by calculating the LOLE for up to ten different load levels and computes a weighted-average value based on the input

[25] Located on ISO-NE's website at: http://www.iso-ne.com/static-assets/documents/trans/celt/report/2014/2014_celt_report_rev.pdf.

probabilities. Load forecast uncertainty multipliers are then used to account for load uncertainty related to weather. These are the *"per unit"* multipliers used for computing the loads used to calculate the reliability indices. Each per unit multiplier represents a load level, which is assigned a probability of that load level occurring. The mean, or 1.0 multiplier, represents the 50/50 forecast for peak load. These uncertainty multipliers are allowed to vary by month.

The summer 2018 peak load forecast distribution is shown in Table 9. The values range from the 10th percentile, representing peak loads with a 90% chance of being exceeded, to the 95th percentile peak load, which represent peak loads having only a 5% chance of being exceeded. The median (50/50) of the forecast distribution is termed the *expected value* because the realized level is equally likely to fall either above or below that median value. The median value is reported to facilitate comparisons, but the inherently uncertain nature of the load forecast is modeled by the load forecast uncertainty multipliers used as an input to the GE MARS Model.

Table 9: Summer 2018 Peak Load Forecast Distribution (MW)

Year	10/90	20/80	30/70	40/60	50/50	60/40	70/30	80/20	90/10	95/5
2018/19	29,045	29,275	29,510	29,935	30,005	30,310	30,860	31,310	32,430	33,120

Existing Capacity Resources

Market Rule 1, Section III.12.7.2 details what shall be modeled within the ICR Related Values calculations as capacity, as defined by the following:

(a) All Existing Generating Capacity Resources,

(b) Resources cleared in previous Forward Capacity Auctions or obligated for the relevant Capacity Commitment Period,

(c) All Existing Import Capacity Resources backed by a multi-year contract(s) to provide capacity into the New England Balancing Authority area, where that multi-year contract requires delivery of capacity for the Commitment Period for which the Installed Capacity Requirement is being calculated, and

(d) Existing Demand Resources that are qualified to participate in the Forward Capacity Market and New Demand Resources that have cleared in previous Forward Capacity Auctions and obligated for the relevant Capacity Commitment Period and Other Demand Resources in existence during the ICAP Transition Period.

Section III.12.7.2 also states that the rating of the Existing Generating Capacity Resources, Existing Demand Resources and Existing Import Capacity Resources used in the calculation of the ICR Related Values shall be the summer Qualified Capacity value of such resources for the relevant zone. The Qualified Capacity value is based on a five-year median capacity rating for each resource.

Summaries of resources categorized as Existing Capacity within the ICR Related Values calculations are provided in the sections below.[26] It should be noted that with the exception of Intermittent Power Resources (IPR), only summer capacity values are used within the calculation of the ICR Related Values.

For the 2018/19 CCP, a total of approximately 319 MW of resources were at risk of having their FCA Qualified Capacity administratively set by ISO-NE to the lesser of their summer or winter Qualified Capacity rating due to Market Rule III.13.1.2.2.5.2, which relates to an Existing Capacity resource which has a higher summer Qualified Capacity than winter Qualified Capacity. While resources in this situation had opportunities to mitigate this potential derating, ISO-NE did not know with certainty the exact amount of the administratively reduced capacity and therefore, these MWs were not removed from the model for the FCA9 ICR Related Values calculation.

For the 2018/19 FCA ICR Related Values calculations, there were a total of 32,842 MW of capacity resources modeled. These capacity resources are made up of generating, intermittent, demand and import resources along with a reduction in generating capacity to account for exports and de-ratings of import capacity. These resources are described in more detail in Table 10 – Table 15 of this report.

Generating Resources

Market Rule 1, Section III.13.1.2.2.1.1 states that the summer Qualified Capacity of a Generating Resource is calculated as the median of the most recent five summer Seasonal Claimed Capability (SCC) ratings with only positive, non-zero ratings included within the calculation. Generating resources, by Load Zone, used within the ICR Related Values calculations were based on Qualified Existing Generating Resources for the 2018/19 CCP at the time of the ICR calculation and are summarized in Table 10.

Table 10: Existing Qualified Generating Capacity by Load Zone (MW)

Load Zone	Summer
MAINE	2,888.145
NEW HAMPSHIRE	4,070.494
VERMONT	255.102
CONNECTICUT	8,255.015
RHODE ISLAND	1,861.432
SOUTH EAST MASSACHUSETTS	4,471.042
WEST CENTRAL MASSACHUSETTS	3,880.929
NORTH EAST MASSACHUSETTS & BOSTON	3,235.563
Total New England	**28,917.722**

[26] For detailed data on the Qualified Existing Resources that participated in the FCA9 see: http://www.iso-ne.com/static-assets/documents/2014/11/er15-___-000_11-3_14_fca_9_info_filing_public_version.pdf.

Intermittent Power Resources

Section III.13.1.2.2.2 of Market Rule 1 discusses the rating methodology of resources considered Intermittent Power Resources (IPR). IPR are defined as wind, solar, run-of-river hydro-electric and other renewable resources that do not have direct control over their net power output.

Summer and winter capacities, by Load Zone, of existing IPR used within the ICR Related Values calculations were those that have Qualified as Existing Generating Resources for the 2018/19 CCP and are shown in Table 11.

Table 11: Existing IPR by Load Zone (MW)

Load Zone	Summer	Winter
MAINE	267.626	392.759
NEW HAMPSHIRE	167.628	222.733
VERMONT	79.038	121.579
CONNECTICUT	186.092	202.197
RHODE ISLAND	4.684	6.435
SOUTH EAST MASSACHUSETTS	75.866	77.907
WEST CENTRAL MASSACHUSETTS	59.642	93.077
NORTH EAST MASSACHUSETTS & BOSTON	70.231	72.023
Total New England	**910.807**	**1,188.710**

Demand Resources

To participate in the FCA as a Demand Resource, a resource must meet the definitions and requirements of Market Rule 1, Section III.13.1.4.1. Existing Demand Resources are subject to the same qualification process as Existing Generating Capacity Resources.

Market Rule 1, Section III.12.7.2 states that the rating of Demand Resources used within the calculation of the ICR Related Values shall be the summer Qualified Capacity value. The summer Qualified Capacity of a Demand Resource is rated based on Measurement and Verification analysis performed during the resource Qualification process.

Existing Demand Resources, by Load Zone, used within the ICR Related Values calculations are for the 2018/19 FCA are shown in Table 12. These values are the Existing Qualified values which also reflect the 8% Transmission and Distribution Gross-up applied to Demand Resources.

Table 12: Existing Demand Resources by Load Zone (MW)

Load Zone	On-Peak	Seasonal Peak	Real-Time Demand Response	Real-Time Emergency Gen	Total
MAINE	176.925	0.000	207.892	11.802	396.619
NEW HAMPSHIRE	94.951	0.000	18.707	14.022	127.680
VERMONT	125.420	0.000	37.007	2.866	165.293
CONNECTICUT	80.728	324.316	254.510	138.338	797.892
RHODE ISLAND	172.704	0.000	57.595	33.540	263.839
SOUTH EAST MASSACHUSETTS	252.710	0.000	38.785	15.962	307.457
WEST CENTRAL MASSACHUSETTS	260.352	52.968	91.799	27.798	432.917
NORTH EAST MASSACHUSETTS & BOSTON	486.312	0.000	50.189	26.099	562.600
Total New England	1,650.102	377.284	756.484	270.427	3,054.297

Import Resources

The Summer Qualified Capacity of an Existing Import Capacity Resource modeled within the ICR calculation follows Market Rule 1, Section III.13.1.3.3, which outlines the Qualification Process for Existing Import Capacity Resources.

The rating of imports used within the calculation of the ICR Related Values is the summer Qualified Capacity value, reduced by any submitted de-list bids reflecting the value of a firm contract(s) or any de-ratings due to Transmission Transfer Capability (TTC) limitations. If the overall amount of Existing Qualified Import Capacity over a transmission interface is greater than the transmission interface limit, the capacity of the import(s) being modeled within the ICR calculation is subsequently reduced to a value equal to that of the applicable transmission interface TTC. Table 13 shows the Existing Qualified Import Resources used within the ICR Related Values calculations for the 2018/19 CCP and the corresponding external transmission interface supplying the import capacity (MWs). There were no de-ratings of TTC for the Existing Qualified Import Capacity Resources for 2018/19 CCP. However; there was a 30 MW de-rating of generating capacity to reflect the value of the Vermont Joint Owners (VJO) contract.

Table 13: Existing Import Resources (MW)

Import Resource	Summer	External Interface
VJO - Highgate	6.000	Hydro-Quebec Highgate
NYPA - CMR	68.800	New York AC Ties
NYPA - VT	14.000	New York AC Ties
Total MW	88.800	

Export Bids

An Export Bid is a Participant bid that may be submitted by certain resources in the FCA to export capacity to an external Balancing Authority area, as described in Section III.13.1.2.3.2.3 of Market Rule 1.

Market Rule 1 Section III.12.7.2 paragraph e) states that:

"*...capacity associated with Export Bids cleared in previous Forward Capacity Auctions and obligated for the relevant Capacity Commitment Period*" shall be excluded from the ICR Related Values calculation.

Only one capacity export was modeled within the ICR Related Values calculation assumptions. This is the 100 MW sale of capacity to the Long Island Power Authority (LIPA) over the Cross-Sound Cable, which is modeled as a reduction in capacity from the unit-specific resource backing the export contract.

Table 14: Capacity Exports (MW)

Export	Summer
LIPA over Cross-Sound Cable	100.000

New Capacity Resources

Market Rule 1, Section III.12.7.2 describes the capacity resources that were modeled within the ICR calculations as the aggregate amount of Existing Generation Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources. Resource capacity that qualifies as a New Capacity Resource is not modeled within the ICR calculation.

Resources Used to Calculate Locational Requirements

The LRA and TSA values, used to determine the LSR for the import-constrained Connecticut, NEMA/Boston and SEMA/RI Capacity Zones are calculated with resource locations identified within the ISO-NE's Regional System Plan (RSP) sub-areas representing Connecticut, Boston and SEMA/RI combined, respectively. These resources are used as proxies for resources located within those Capacity Zones. This is done because the TTC calculated for the interfaces studied in the locational requirements analyses use the ISO-NE RSP sub-areas and are thus calculated for the RSP zones. For Demand Resources, the Existing Qualified Demand Resources for the Capacity Zone are used because the RSP values available would have to be estimated (particularly for the Passive Demand Resources) since actual locations for some of these resources are not currently available.

For the 2018/19 FCA ICR Related Values, there are no differences between the resources located within the corresponding RSP zones versus the resources located within the Connecticut, NEMA/Boston and combined SEMA/RI Capacity Zones. Table 15 shows the resources modeled in each of the Capacity Zones with a locational requirement along with the New England values.

Table 15: Resources Used in the LSR Calculations (MW)

Type of Resource	New England	Connecticut	NEMA/Boston	SEMA/RI
Generating Resources	28,787.722	8,255.015	3,235.563	6,332.474
Intermittent Power Resources	910.807	186.092	70.231	80.550
Passive Demand Resources	2,027.386	405.044	486.312	425.414
Active Demand Resources	1,026.911	392.848	76.288	145.882
Import Resources	88.800	-	-	-
Total MW Modeled	**32,841.626**	**9,238.999**	**3,868.394**	**6,984.320**

Transmission Transfer Capability

Market Rule 1, Section III.12.5 requires that ISO-NE update the transmission interface transfer capability for each internal and external transmission interface for the 2018/19 CCP, if necessary.[27] Although external transmission transfer capability is not used within the ICR calculation, they are used in the determination of tie benefits, including HQICCs, and will also be used within the FCA to limit the purchases of external installed capacity. Internal transmission transfer capability limits are used in the determination of any LSR and MCL values and tie benefit values.

External Transmission Transfer Capability

Table 16 shows the External TTC values that were used within the 2018/19 tie benefits study.

Table 16: Transmission Transfer Capability of New England External Interfaces Modeled in the Tie Benefits Study (MW)

External Interfaces Into New England	Summer TTC
Hydro-Quebec to New England via Phase II	1,400
Hydro-Quebec to New England via Highgate	200
New Brunswick to New England	700
New York to New England via New York AC Ties	1,400
New York to New England via Cross-Sound Cable DC Interface	0

External Transmission Interface Availability

The forced and scheduled outage rates of the transmission interfaces connecting ISO-NE to its neighboring Balancing Authorities are based on historical data provided by these Balancing Authorities. These values are shown in Table 17 and include the average forced outage rate (%) and maintenance outage rate (in weeks) as used in the models that

[27] For more detailed information on the RSP14 TTC analysis see a presentation from the March 17, 2014 Planning Advisory Committee (PAC) meeting: http://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2014/mar172014/a8_rsp14_transmission_interface_transfer_capabilities.pdf.

are associated with each external transmission interface. These assumptions were developed in 2011 and include data from the five-year period of 2006 through 2010.[28]

Table 17: External Interface Outage Rates (% and Weeks)

External Ties	Forced Outage Rate (%)	Maintenance (Weeks)
Hydro-Quebec Phase II	0.39	2.7
Highgate	0.07	1.3
New Brunswick Interface	0.08	0.4
New York AC Interface	0	0
Cross-Sound Cable	0.89	1.5

Internal Transmission Transfer Capability

For the 2018/19 FCA, ISO-NE evaluated three Capacity Zones relating to their LRA, using the zone under study and *Rest of New England* methodology. The first is the Connecticut Capacity Zone, which is modeled as import-constrained into Connecticut. The second is the NEMA/Boston Load Zone, which is modeled as import-constrained into NEMA/Boston. The third is the combined SEMA/RI Capacity Zone, which is modeled as import-constrained into SEMA/RI. In addition, the TSA analysis, which uses both the N-1 limit and the N-1-1 limit, was performed for these three Capacity Zones.[29]

Table 18 shows the N-1 and N-1-1 internal TTC for the Connecticut Import interface, Boston Import interface, and SEMA/RI Import interface used to calculate LSR within the Connecticut, NEMA/Boston and SEMA/RI Capacity Zones, respectively. These TTC values are part of an annual study of transmission topology and are documented in the 2014 Regional System Plan (RSP14).

With the exception of the TTC values for the Connecticut, NEMA/Boston and SEMA/RI Capacity Zones which are modeled in the LSR calculations, remaining internal interfaces with a calculated TTC are modeled in the tie benefits study. For the 2018/19 CCP tie benefits study, these internal interfaces are documented as part of RSP14 and are available on slide 12 of a presentation given on March 17, 2014 to the Planning Advisory Committee (PAC):
http://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2014/mar172014/a8_rsp14_transmission_interface_transfer_capabilities.pdf.

[28] For more detail on external tie availability assumptions see: http://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/relblty_comm/pwrsuppln_comm/mtrls/2011/jul152011/external_tie_outage_assumptions.pdf.

[29] The term N-1 represents the first contingency and the term N-1-1 represents the second contingency.

Table 18: Internal Transmission Transfer Capability Modeled in the LSR Calculations (MW)[30,31,32]

Interface		2018/19
Boston Import	N-1	4,850
	N-1-1	4,175
CT Import	N-1	2,950
	N-1-1	1,600
SEMA/RI Import	N-1	786
	N-1-1	473

OP-4 Load Relief

The New England resource planning reliability criterion requires that adequate capacity resources be planned and installed such that disconnection of firm load would not occur more often than once in 10 years due to a capacity deficiency, after taking into account the load and capacity relief obtainable from implementing Emergency Operating Procedures (EOPs). ISO New England Operating Procedure No. 4 – *Action During a Capacity Deficiency* (OP-4) is the EOP for New England. In other words, load and capacity relief assumed obtainable from implementing certain OP-4 actions are direct substitutes for capacity resources in meeting the once in 10 years disconnection of firm load criterion.

Under the FCM, the assumed emergency assistance (i.e. tie benefits) available from neighboring Balancing Authority areas, load reduction from implementation of 5% voltage reduction,[33] and capacity available from the dispatch of Real-Time Demand Resources[34] and Real-Time Emergency Generating Demand Resources[35] all constitute actions that ISO-NE System Operators can invoke under OP-4 to balance real-time system supply with demand (as applicable under both actual or forecast capacity shortage conditions). These actions are used as load and capacity relief assumptions within the development of the ICR Related Values.

[30] The Boston Import TTC shown in Table 18 includes the impact of the retirement of the Salem Harbor station and inclusion of the advanced NEMA/Boston transmission upgrades in the analysis. The proposed Footprint generating project was not included in the Boston Import interface import capability and will be evaluated at a future date.

[31] The Connecticut Import shown includes The New England East-West Solution (NEEWS), expected to be in-service by December 2015 and has been certified and accepted by ISO-NE to be included in FCA9 analyses.

[32] The Maine-New Hampshire interface TTC value of 1,900 MW was used in the indicative MCL analysis and Capacity Zone Trigger Analysis.

[33] Action 6 and 8 of OP4.

[34] Action 2 of OP4.

[35] Action 6 of OP4.

Tie Benefits

In the event of a capacity shortage in New England, tie benefits reflect the amount of emergency assistance that is assumed will be available to ISO-NE from its neighboring Balancing Authority areas, without jeopardizing system reliability in either the ISO-NE Balancing Authority area or its neighboring Balancing Authority areas. Tie Benefits are an input into the determination of the ICR Related Values, and in fact, displace the MW amount of resources that need to be purchased internal to New England within the FCA by an almost one to one ratio.

Tie Benefits Calculation Methodology

ISO-NE used the procedures for calculating tie benefits documented in Section III.12.9 of Market Rule 1. The tie benefits calculation methodology includes the calculation of tie benefits at the system-wide level and for each of the directly interconnected neighboring Balancing Authority areas of Québec, New Brunswick (Maritimes) and New York.

The tie benefits study for the 2018/19 CCP was conducted using the probabilistic GE MARS program to model projected system conditions for that timeframe. The methodology for calculating the total tie benefits, individual Balancing Authority tie benefits and the tie benefits assumed for individual interconnections is documented in more detail in Figure 8.

Figure 8: Summarization of the Tie Benefits Calculation Process[36]

- ***Process 1.0***
  - Calculate the tie benefits values for all possible interconnection states using isolated New England system as the reference
- ***Process 2.0***
  - Calculate initial total tie benefits for New England from all neighboring Balancing Authority Areas
- ***Process 3.0***
  - Calculate initial tie benefits for each individual neighboring Balancing Authority Area
  - Pro-rate tie benefits values of individual Balancing Authority Areas based on the total tie benefits, if necessary
- ***Process 4.0***
  - Calculate initial tie benefits for individual interconnection or group of interconnections
  - Pro-rate tie benefits values of individual interconnection or group of interconnections based on the individual Balancing Authority Area tie benefits, if necessary
- ***Process 5.0***
  - Adjust tie benefits of individual interconnection or group of interconnections to account for capacity imports
- ***Process 6.0***
  - Calculate the final tie benefits for each individual neighboring Balancing Authority Area
- ***Process 7.0***
  - Calculate the final total tie benefits for New England

Total Tie Benefits

Total tie benefits were calculated using the results of a probabilistic analysis that determines LOLE indices for the ISO-NE and neighboring Balancing Authority areas. The LOLE calculations were first done on an interconnected basis that included all existing connections (tie lines) between ISO-NE's directly connected neighboring Balancing Authority areas. This established the minimum amount of capacity that each area needs in order to comply with the NPCC resource adequacy requirements of 0.1 days per year LOLE.

These LOLE calculations were then repeated with ISO-NE isolated from all neighboring Balancing Authority areas. The tie benefits are then quantified by adding firm capacity resources within the isolated ISO-NE Balancing Authority area, until the LOLE is returned back to 0.1 days per year. The resources which were added to return ISO-NE to a LOLE of 0.1 days per year are called *"firm capacity equivalents"* and are assumed to be ISO-NE's total tie benefits.

Based on the methodology described above, a total of 1,970 MW of tie benefits are assumed within the ICR calculations for the 2018/19 CCP.

Individual Balancing Authority Area Tie Benefits

For calculating each Balancing Authority area's individual tie benefits, all the tie lines associated with the Balancing Authority area of interest are treated on an aggregate basis.

[36] A presentation on the 2018/19 Tie Benefits Study was reviewed at the RC on September 16, 2014 which provides more details on the calculation details and study assumptions and is available at http://www.iso-ne.com/static-assets/documents/2014/09/a6_fca9_tie_benefits_study.pdf.

The tie benefits from each Balancing Authority area are calculated for all possible interconnection states. The simple average of these tie benefits from each of these states will represent the calculated tie benefits from that specific Balancing Authority area.

If the sum of the Balancing Authority areas tie benefits is different from the total tie benefits for ISO-NE, then each Balancing Authority area's tie benefits are adjusted (up or down) based on the ratio of the individual Balancing Authority area tie benefits to the total tie benefits.

For the 2018/19 CCP, the individual Balancing Authority area tie benefits were calculated as 1,101 MW for Québec, 523 MW for the Maritimes, and 346 MW for New York.

Individual Tie (or Group of Ties) Tie Benefits

The tie benefits methodology calls for tie benefits to be calculated for an individual tie or group of ties to the extent that a discrete and material transfer capability can be identified for it. To calculate tie benefits for each tie or group of ties from the external Balancing Authority area of interest into ISO-NE, each is treated independently. The tie benefits for each individual tie or group of ties is calculated for all the interconnection states and the simple average of the tie benefits associated with these interconnections states is the resultant tie benefits for each tie or group of ties.

If the sum of the tie benefits from the individual tie or group of ties relative to their Balancing Authority area's total tie benefits are different, then the tie benefits of each individual tie or group of ties are adjusted (up or down) based on the ratio of the tie benefits of the individual tie or group of ties to the Balancing Authority area's total tie benefits.

For the 2018/19 CCP, individual interconnection tie benefits were determined from Québec over the HQ Phase II facility of 953 MW, 148 MW from Québec over the Highgate facility, 523 MW from the Maritimes over the New Brunswick interface and 346 MW of the New York tie benefits are delivered over the New York AC ties and 0 MW from the Cross-Sound Cable.

Hydro-Québec Interconnection Capability Credits (HQICCs)[37]

Hydro-Québec Interconnection Capability Credits, or HQICCs, are an allocation of the tie benefit over the Hydro-Québec Interconnection to the Interconnection Rights Holders (IHR), which are regional entities that hold certain contractual entitlements (i.e. rights) over this specific transmission interconnection. These rights are monetized as credits in the form of reduced capacity requirements.

[37] The 2018/19 CCP HQICCs values were filed with the Commission in the 2018/19 ICR filing: http://www.iso-ne.com/static-assets/documents/2014/11/er15-___-000_11-6-14_2018-2019_icr_filing.pdf.

The HQICC value is 953 MW, as determined by the tie benefits from Québec over the Phase II facility, and are applicable for every month during the 2018/19 CCP.

Adjustments to Tie Benefits

Processes 5.0 of the current tie benefits methodology requires that that individual interconnections or group of interconnections tie benefit values be adjusted, if necessary to account for the Existing Qualified Import Capacity Resources for 2018/19. If the sum of the tie benefits value and the import capacity is greater than the TTC of the individual interconnection or group of interconnections under study, then the tie benefits value will be reduced.

Process 6.0 of the tie benefits methodology determines the final tie benefits for each neighboring Balancing Authority Area as the sum of the tie benefits from the individual interconnections or groups of interconnections with that Balancing Authority Area, after accounting for any adjustment for capacity imports as determined within Process 5.0.

Final total tie benefits for the New England Balancing Authority Area from all neighboring Balancing Authority Areas is determined within Process 7.0 of the tie benefits methodology as the sum of these neighboring area tie benefits after accounting for any adjustment for capacity imports as determined within Process 6.0.

For the 2018/19 CCP, Table 19 shows the Existing Qualified Import Capacity Resources used to determine if adjustments of tie benefits are necessary as defined within Process 5.0 through Process 7.0 of the tie benefits methodology. For the 2018/19 Tie Benefits Study, no adjustment to tie benefits to account for capacity imports was necessary.

Table 19: Capacity Imports Used to Adjust Tie Benefits by External Interface (MW)

Import	New Brunswick	Hydro-Québec Phase II	Highgate	New York AC Ties
NYPA - CMR				68.8
NYPA - VT				14
VJO - Highgate			6	
Total			6	82.8

The results of the Tie Benefits Study for the 2018/19 CCP are summarized in Table 20.

Table 20: 2018/19 Tie Benefits (MW)

Balancing Authority Area	Summer	Winter
Québec via Phase II	953	953
Québec via Highgate	148	148
Maritimes	523	523
New York	346	346
Total Tie Benefits	1,970	1,970

Comparison of the 2018/19 and 2017/18 CCP's Tie Benefits

Table 21 gives a comparison of the 2018/19 CCP tie benefits calculated for FCA9 and the 2017/18 CCP tie benefits calculated for FCA8.

Table 21: 2018/19 versus 2017/18 Tie Benefits (MW)

Balancing Authority Area	2018/19 FCA9	2017/18 FCA8
Québec via Phase II	953	1,068
Québec via Highgate	148	83
Maritimes	523	492
New York	346	227
Total Tie Benefits	1,970	1,870

As the results show, the total tie benefits for the New England Balancing Authority Area has increased by 100 MW for the 2018/19 CCP versus the 2017/18 CCP. With the retirement of the Vermont Yankee nuclear generating station in the north and the Brayton Point generating station in the south, the North-South interface within New England has become even more constrained. The additional constraint of this transmission interface has shifted tie benefits from the northern side (Québec) to the southern side (New York) of the North-South transmission interface, which results in an increase in the tie benefit contributions from the New York over the New York AC ties and a subsequent decrease from Québec over the Phase II transmission interface.

5% Voltage Reduction

In addition to tie benefits, load reduction from implementation of a 5% voltage reduction is used in the development of the ICR Related Values. This constitutes an action that ISO-NE System Operators can invoke in real-time under ISO-NE OP-4, to balance system supply with demand under actual or expected capacity shortage conditions.

The amount of load relief assumed obtainable from invoking a 5% voltage reduction is based on the performance standard established within ISO New England's Operating Procedure No. 13, *Standards for Voltage Reduction and Load Shedding Capability*

("Operating Procedure No. 13" or OP13). ISO-NE Operating Procedure No. 13 requires that…

> *"…each Market Participant with control over transmission/distribution facilities must have the capability to reduce system load demand at the time a voltage reduction is initiated by at least one and one-half (1.5) percent through implementation of a voltage reduction."*

The calculation of the amount of 5% voltage reduction to be assumed within the ICR Related Values calculations uses the benchmark 1.5% value of load relief as specified in Appendix A of OP-4.[38] This benchmark reduction value is set based on the voltage reduction requirements of Operating Procedure No. 13, rather than the self-reported values submitted by Market Participants with control over transmission/distribution facilities.

For the 2018/19 ICR calculation, the methodology for calculating the amount of 5% voltage reduction assumed within the ICR remains the same as used in the prior year's ICR calculations. This methodology uses the 90/10 peak load forecast and assumes that all Demand Resources will have already been implemented, and thus, will have reduced the 90/10 load value at the time of peak or OP-4 invocation.

Thus the voltage reduction load relief values assumed as offsets against the ICR are calculated as the 1.5% voltage reduction assumption times the 90/10 peak load forecast after accounting for the amount of all Demand Resources (with the exception of limiting the amount of Real-Time Emergency Generation to 600 MW, the maximum amount purchased in the auction to meet the ICR, if necessary), which is assumed to be already implemented and therefore not contributing to the 1.5% reduction in load. Figure 9 shows this formula:

Figure 9: Formula for Calculating 5% Voltage Reduction Assumption

$$\lceil 90/10\,Peak\ Load\ MW - Demand\ Resource\ MW \rceil \times 1.5\%$$

Table 22 shows the amount of voltage reduction (MW) modeled as ISO-NE OP-4 load relief from Actions 6 & 8 for each of the months of the 2018/19 CCP within the ICR calculations.

[38] Appendix A of OP-4is available at: http://www.iso-ne.com/static-assets/documents/rules_proceds/operating/isone/op4/op4a_rto_final.pdf.

Table 22: OP-4 Action 6 & 8 Modeled (MW)

	90/10 Peak Load	Passive Demand Resources	Real-Time Demand Resources	Real-Time Generating Resources	Action 6 & 8 5% Voltage Reduction
Jun 2018 - Sep 2018	32,430	2,027	756	270	441
Oct 2018 - May 2019	23,940	1,834	739	260	317

Operating Reserve

It is assumed that during peak load conditions, under extremely tight capacity situations, ISO-NE System Operations will maintain a minimum level of at least 200 MW of operating reserves for transmission system protection, prior to invoking manual load shedding procedures, if necessary. This pre-load shedding OP-4 situation is modeled as operating reserve within the ICR calculation by withholding this amount of capacity from serving regional peak load.

Proxy Units

Section III.12.7.1 of Market Rule 1 discusses the addition of proxy units to the ICR model. Proxy units are required when the available resources are insufficient for the unconstrained New England Balancing Authority area to meet the resource adequacy planning criterion specified in Section III.12.1. In the model, proxy units are used as additional capacity to determine the ICR, LRA, MCL and capacity requirement values for the Demand Curve.

The proxy units used in the ICR model reflect the resource capacity and outage characteristics such that when the proxy units are used in place of all other resources in the New England Balancing Authority area, the reliability, or LOLE, of the New England Balancing Authority area does not change. The outage characteristics are the summer capacity weighted average availability of the resources in the New England Balancing Authority area as determined in accordance with Market Rule 1, Section III.12.7.3. The capacity of the proxy unit is determined by adjusting the capacity of the proxy unit until the LOLE of the New England Balancing Authority area is equal to the LOLE calculated while using the capacity assumptions described in Section III.12.7.2.

In May 2014, ISO-NE conducted a study to revise the proxy unit characteristics with the most recent system conditions in anticipation of requiring the use of proxy units within the FCA9 ICR model.[39] At the time of the study, the FCA8 (2017/18) ICR model was used as it was the most recent available ICR model.

[39] This study was presented to the PSPC on May 22, 2014 and is available at: http://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/relblty_comm/pwrsuppln_comm/mtrls/2014/may222014/proxy_unit_2014_study.pdf.

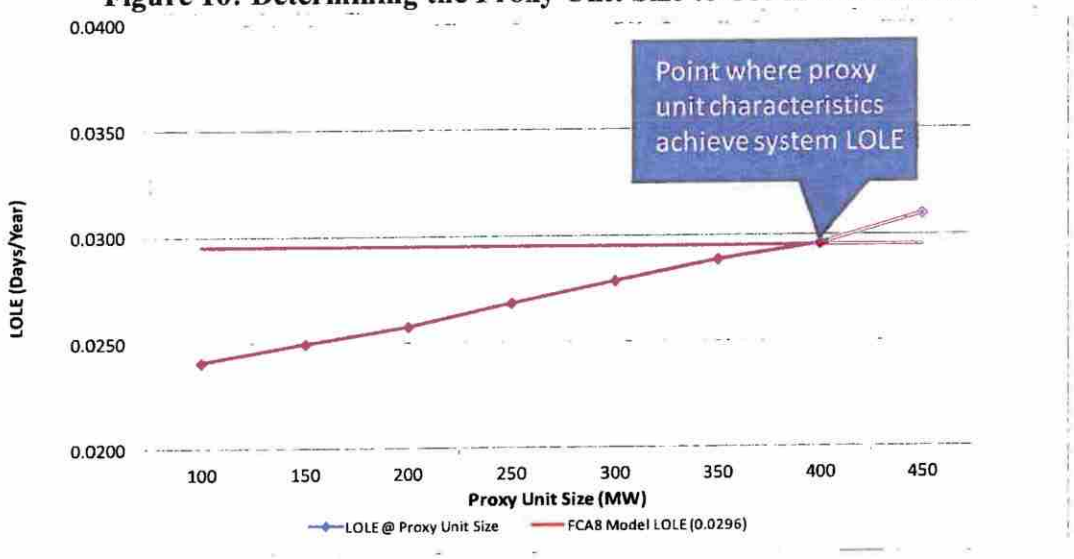
The procedure used to determine the new proxy unit size is to:

- Determine the initial LOLE of the system using the FCA8 ICR Model
- Determine the average availability of the system for both forced and scheduled outages (5.47% Forced Outage Rate (FOR) and 4 weeks of maintenance)
- Replace all resources in the system with proxy units with the average system availability
- Adjust the capacity ratings of the proxy units within the model until the initial system LOLE is achieved

Using the methodology above, the results showed that with the average system FOR of 5.47% and four weeks of maintenance for the FCA8 system, the appropriate size of the proxy units is 400 MW.

Figure 10 below, shows the point at which the LOLE of the model at various proxy unit sizes intersects the FCA8 existing system LOLE of 0.0296 days/year is 400 MW.

Figure 10: Determining the Proxy Unit Size to Use in ICR Models



Using the newly developed proxy unit size of 400 MW, four proxy units were needed for the 2018/19 ICR calculation, one proxy unit was needed in the model to calculate the capacity requirements for the Demand Curve at 1-in-5 LOLE and 11 proxy units were required to calculate the capacity requirements for the Demand Curve at 1-in-87 LOLE.

When modeling transmission constraints for the determination of LRA, the same proxy units may be added to the import-constrained zone (if needed), otherwise they will be added elsewhere in the rest of the New England Area. For the SEMA/RI LRA analysis, two proxy units needed to bring the New England system to the one day in ten years

LOLE reliability criteria were subsequently added to the SEMA/RI combined sub-area in order to calculate the SEMA/RI LRA.

Summary

Table 23 summarizes the capacity resources, proxy units and OP-4 assumptions used for the calculation of the 2018/19 ICR Related Values.

Table 23: Summary of Resource and OP-4 Assumptions (MW)

Type of Resource/OP-4	2018/19 FCA
Generating Resources	28,917.722
Intermittent Power Resources	910.807
Demand Resources	3,054.297
Import Resources	88.800
Export Delist	(100.000)
Import Deratings	(30.000)
OP-4 Voltage Reduction	441.000
Minimum Operating Reserve	(200.000)
Tie Benefits (Includes 953 MW of HQICCs)	1,970.000
Proxy Units	1,600.000
Total MW Modeled in ICR	**36,652.626**

Availability

Generating Resource Forced Outages

A five-year, historical average of unit-specific forced outage assumptions is determined for each generating unit that qualified as an Existing Generating Capacity Resource, using the most recent available data of monthly Equivalent Forced Outage Rate - Demand (EFORd) values from NERC's Generating Availability Data System (GADS).[40] The NERC GADS data, which is submitted by owners of regional generators to ISO-NE for the months of January 2009 through December 2013, was used to create an EFORd value for each generating unit that submits such data. The NERC Class Average data is used as a substitute for immature units and for units that are not required to submit NERC GADS data.

Table 24 shows the capacity-weighted, average EFORd values resulting from summing the individual generator data by generating resource category, weighted by individual capacity ratings. This is provided for informational purposes only. In the GE MARS model, the calculated EFORd for each generating resource is used as a generator-specific input assumption.

Generating Resource Scheduled Outages

A weekly representation of a generator's scheduled (maintenance) outages is another input assumption that goes into the GE MARS model. Included within the scheduled outages are annual maintenance outages and short-term outages, scheduled more than 14 days in advance of their outage date. A single value is then calculated for each generator, based on a five-year historical average. In addition to the EFORd data, Table 24 illustrates the average annual maintenance weeks assumed for each type of unit category, weighted by the summer capability. NERC Class Average data is used to calculate the average maintenance weeks assumption for immature units.

Table 24: Generating Resource EFORd (%) and Maintenance Weeks by Resource Category

Resource Category	Summer MW	Assumed Average EFORd (%) Weighted by Summer Ratings	Assumed Average Maintenance Weeks Weighted by Summer Ratings
Combined Cycle	12,523	3.6	5.8
Fossil	6,254	14.9	5.2
Nuclear	4,024	3.1	3.9
Hydro (Includes Pumped Storage)	2,931	4.6	6.5
Combustion Turbine	2,908	9.5	2.3
Diesel	193	6.5	1.0
Miscellaneous	86	14.2	1.8
Total System	28,918	6.7	5.1

[40] For more information on GADS, see the NERC website located at: http://www.nerc.com/pa/RAPA/gads/Pages/default.aspx.

Intermittent Power Resource Availability

The Qualified Capacity of an Intermittent Power Resource (IPR) is the resource's median output during "Reliability Hours," as averaged over a period of five years. Since this methodology takes into account the resources' historic availability as it applies to their FCM capacity ratings, these resources are assumed 100% available within the ICR model.

Demand Resources Availability

Passive Demand Resources

Table 25 tabulates the availability assumption of the Passive Demand Resources in the On-Peak and Seasonal Peak categories of Demand Resources. These resources are considered 100% available within the ICR model. These two categories consist of passive resources such as energy efficiency or conservation, which are considered always "*in service*" and as such, are subsequently assumed to be 100% available. The total average availability for all Passive Demand Resources is, therefore, 100%.

Table 25: Passive Demand Resources – Summer (MW) and Availability (%)

Load Zone	On-Peak		Seasonal Peak	
	Summer (MW)	Availability (%)	Summer (MW)	Availability (%)
MAINE	176.925	100	-	-
NEW HAMPSHIRE	94.951	100	-	-
VERMONT	125.420	100	-	-
CONNECTICUT	80.728	100	324.316	100
RHODE ISLAND	172.704	100	-	-
SOUTH EAST MASSACHUSETTS	252.710	100	-	-
WEST CENTRAL MASSACHUSETTS	260.352	100	52.968	100
NORTH EAST MASSACHUSETTS & BOSTON	486.312	100	-	-
Total New England	1,650.102	100	377.284	100

Active Demand Resources

The historical performance, from both audits and real time events, of Active Demand Resources (those in the Real-Time Demand Response and Real-Time Emergency Generators categories) are used to create the Active Demand availability assumption for use within the ICR calculation.[41]

For the calculation of ICR for the 2018/19 CCP, historical Demand Resource performance data for four years under FCM was used. This historical data consists of both OP-4 events and performance audits that occurred during the summer and winter of

[41] A detailed discussion of the Demand Resource availability assumption is available here: http://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/relblty_comm/pwrsuppln_comm/mtrls/2014/jun302014/2014_dr_availability.pdf.

2010 through 2013. At the June 24, 2014 PSPC meeting, ISO-NE proposed using an availability assumption for Active Demand Resources based on the summer and winter Active Demand performance data for the years 2010 through 2013, weighted by the capacity (MW) of the resources within each Load Zone for each year. After the presentation of this data to the PSCPC and subsequent stakeholder discussions, it was decided to use this proposal within the ICR Related Values calculations.

Table 26 shows the performance rates for Active Demand Resources applied to the Demand Resources by Load Zone and type of resource that are qualified as Existing Resources to participate in the 2018/19 FCA. This gives an average Active Demand Resource availability assumption of 88% for both Real-Time Demand Response and Real-Time Emergency Generators. The total average Demand Resource availability assumption for all Demand Resources, both Active and Passive, is 96%. This is an increase in performance of approximately 2% over prior values assumed within the 2017/18 ICR Related Values calculation, which used historical data from summer 2010 through 2012. In the ICR model, Demand Resources are modeled in blocks consisting of the type of Demand Resource by Load Zone. The overall availability is shown for informational purposes only.

Table 26: Demand Response Resources Summer (MW) and Availability (%)

Load Zone	Real-Time Demand Response		Real-Time Emergency Generators	
	Summer (MW)	Availability (%)	Summer (MW)	Availability (%)
MAINE	207.892	99	11.802	93
NEW HAMPSHIRE	18.707	88	14.022	99
VERMONT	37.007	92	2.866	82
CONNECTICUT	254.510	82	138.338	85
RHODE ISLAND	57.595	85	33.540	90
SOUTH EAST MASSACHUSETTS	38.785	84	15.962	84
WEST CENTRAL MASSACHUSETTS	91.799	89	27.798	89
NORTH EAST MASSACHUSETTS & BOSTON	50.189	81	26.099	89
Total New England	756.484	88	270.427	88

Difference from 2017/18 FCA ICR Related Values

Change in ICR

In an effort to quantify the effects that each input assumption has on the determination of ICR results, ISO-NE began with the input assumptions associated with the ICR calculated for the 2017/18 CCP and substituted each assumption individually with the corresponding 2018/19 CCP assumption. The net of these changes within the ICR value, as a result of each individual input assumption change, was then considered as the overall effect of the changed assumption set. Table 27 lists the assumptions for each CCP and their subsequent effect on the resultant ICR value. Note that the sum of the individual assumption effects on ICR do not necessarily sum to the total difference in ICR due to the interplay of the various assumptions within the model when they are modeled concurrently.

Table 27: Summary of ICR Input Assumptions for 2018/19 vs. 2017/18

Assumption	2018/2019 FCA		2017/2018 FCA		Effect on ICR (MW)
Tie Benefits & Updated External Interface Outage Assumptions	346 MW New York		227 MW New York		-213
	523 MW Maritimes		492 MW Maritimes		
	953 MW Quebec (HQICCs)		1068 MW Quebec (HQICCs)		
	148 MW Quebec via Highgate		83 MW Quebec via Highgate		
Total	1,970 MW		1,870 MW		
	MW	Weighted Forced Outage	MW	Weighted Forced Outage	
Generation & IPR	29,699	6.5%	32,098	5.8%	178
Demand Resources	3,054	4.0%	3,416	5.8%	-85
Imports	89	0.0%	89	0.0%	0
	MW		MW		
Load Forecast	30,005		29,790		348
	MW	%	MW	%	
OP 4 5% VR	441	1.50%	432	1.50%	-9
	MW		MW		
ICR	35,142		34,923		219

As shown in Table 27, there are several assumptions which have a notable effect on the ICR. The first is the increase in the load forecast for the 2018/19 CCP versus the 2017/18 CCP. While the 50/50 load forecast is shown for reference purposes, when calculating the ICR, a full distribution of possible peak loads is modeled along with moments of the distribution: the mean, standard deviation and 3rd cummulant which together form the load forecast uncertainty within the model. Other factors in addition to the load forecast uncertainty also can affect the amount of installed capacity needed to meet the load forecast, particularly the resource size and availabilities modeled. So while the annual increase in the 50/50 load forecast is 215 MW as shown, there is a decrease in the ALCC (amount of additional load) the system is able to support of 309 MW. This translates to the system requiring 348 MW of additional installed capacity to meet the load forecast in 2018/19 versus 2017/18.

The change in the tie benefits assumed for 2018/19 versus 2017/18 accounts for a decrease in ICR of 213 MW. The 100 MW increase in total tie benefits means that approximately 115 MW less installed capacity is needed within New England. Also, the decrease in HQICCs from 1,068 MW for 2017/18 to 953 MW for 2018/19 accounts for a decrease in ICR of 98 MW since HQICCs are added back into the ICR and are treated differently than other resources and are not adjusted by the ALCC amount.

The third assumption with a notable effect on ICR is the change in generating resource EFORd calculated for the 2018/19 ICR Related Values from those calculated for the 2017/18 ICR Related Values. As described in this Report's section on Resource Availability, the EFORd used in the ICR Related Values calculation is derived from the most recent five years of GADS data. The 5-year weighted average system-wide generator EFORd calculated for the 2018/19 ICR calculation is approximately 14% higher than the EFORd values calculated for the 2017/18 ICR calculation. This decrease in generating resource availability caused the ICR to increase by 178 MW because more resources are needed to meet the capacity requirements in New England if these resources are less reliable than in previous years.

Table 28 shows a comparison in the 2018/19 versus the 2017/18 CCP ICR calculation average EFORd by generator type.

Table 28: Assumed 5-Year Average % EFORd Weighted by Summer Ratings for 2018/19 versus 2017/18 ICR Calculations

Resource Category	2018/19 FCA9 5-year Average EFORd for the Years 2009-2013	2017/18 FCA8 5-year Average EFORd for the Years 2008-2012
Combined Cycle	3.6	3.9
Fossil	14.9	9.9
Nuclear	3.1	2.6
Hydro (Includes Pumped Storage)	4.6	5.1
Combustion Turbine	9.5	8.5
Diesel	6.5	7.8
Miscellaneous	14.2	15.8
Total System	6.7	5.9

The final assumption with a notable effect on the ICR is the change in Demand Resource type of resource and assumed availability. While the change in assumed availability for active Demand Resources did not vary greatly from the values used for the 2017/18 FCA ICR calculation, the increase in the amount of passive resources and corresponding decrease in active resources improved the overall Demand Resource availability assumption (calculated as 1 – DR Performance) from 5.8% to 4.0% therefore decreasing ICR by 85 MW in 2018/19 versus 2017/18. Table 29 below shows the breakdown by type of Demand Resource and corresponding performance for the 2018/19 versus 2017/18 ICR calculations.

Table 29: Comparison of Demand Resources (MW) & Performance (%) for 2018/19 versus 2017/18 ICR Calculations

Type of Demand Resource	2018/19 FCA9		2017/18 FCA8	
	MW	%	MW	%
Passive Demand Resources	2,027	100	1,769	100
Real-Time Demand Response	756	88	1,165	89
Real-Time Emergency Generators	270	88	483	86
Total Demand Resources	3,054	96	3,416	94

Change in LRA Requirement

Table 30 shows the difference in the assumptions and results of the 2018/19 LRA Requirement calculation, as compared to the 2017/18 LRA Requirement calculation for the import-constrained Connecticut and NEMA/Boston Load Zones Capacity Zones. A SEMA/RI locational capacity requirement was calculated for the first time for FCA9, therefore no comparisons are available.

Table 30: Summary of Changes in LRA Requirement for 2018/19 vs. 2017/18

		Connectiuct		NEMA/Boston	
Connecticut Zone		2018/19 FCA9	2017/18 FCA8	2018/19 FCA9	2017/18 FCA8
$Resource_z$	[1]	9,239	9,768	3,868	3,685
$Proxy\ Units_z$	[2]	0	0	0	0
$Firm\ Load\ Adjustment_z$	[3]	1,825	2,282	775	685
FOR_z	[4]	0.074	0.068	0.042	0.044
LRA_z	[5]=[1]+[2]-([3]/(1-[4]))	**7,268**	**7,319**	**3,129**	**2,968**

Change in TSA Requirement

Table 31 shows the difference in the assumptions and results of the 2018/19 TSA Requirement calculation, as compared to the 2017/18 TSA Requirement calculations for the import-constrained Connecticut and NEMA/Boston Load Zones. As noted above, there is no comparison available for the SEMA/RI Capacity Zone TSA since FCA9 is the first time a TSA Requirement was calculated.

Table 31: Comparison of the TSA Requirement Calculation for 2018/19 vs. 2017/18 (MW)[42]

	Connecticut		NEMA/Boston	
	2018/19 FCA9	2017/18 FCA8	2018/19 FCA9	2017/18 FCA8
Sub-area 90/10 Load	8,415	8,330	6,835	6,745
Reserves (Largest unit or loss of import capability)	1,225	1,200	1,412	1,395
Sub-area Transmission Security Need	**9,640**	**9,530**	**8,247**	**8,140**
Existing Resources	9,239	9,768	3,868	3,685
Assumed Unavailable Capacity	-808	-729	-190	-149
Sub-area N-1 Import Limit	2,950	2,800	4,850	4,850
Sub-area Available Resources	**11,381**	**11,839**	**8,528**	**8,386**
TSA Requirement	7,331	7,273	3,572	3,428

Connecticut

The Connecticut LRA decreased for 2018/19 versus the 2017/18 CCP calculation. The primary reason for the decrease in the Connecticut LRA for the 2018/19 CCP versus the 2017/18 CCP is the increase in the N-1 TTC for the Connecticut Import interface that was used to calculate the Connecticut LRA Requirement. The N-1 TTC increased from 2,800 MW to 2,950 MW. This increase in the Connecticut Import TTC is due to transmission upgrades associated with the New England East-West Solution (NEEWS) which is expected to be in-service by December 2015 and has been certified and accepted by ISO-NE to be included in FCA9 analyses. The increase in TTC within the probabilistic LRA analysis translates to an almost one to one MW decrease in the LRA Requirement without considering any other assumption changes.

The Connecticut TSA increased for the 2018/19 CCP versus the 2017/18 CCP. While the increase in the Connecticut Import N-1 and N-1-1 TTC does act to decrease the TTC, other factors such as an increase in the rating of the largest generator used as reserves in the calculation from 1,200 to 1,225 MW, an increase in the 90/10 load forecast of 84 MW and an increase in the amount of unavailable resource MWs of 79 MW (approximately 10%) were enough to offset the increase in TTC and subsequently increase the TSA for Connecticut by 58 MW (less than 1%).

NEMA/Boston

The increase in the NEMA/BOSTON LRA and TSA Requirements for the 2018/19 CCP is primarily due to an increase in the load forecast for the NEMA/Boston sub-area.

[42] The 90/10 load for Connecticut and NEMA/Boston shown are the sub-area loads. The LRA and TSA analyses are preformed on a sub-area basis which is used as proxies for the load zones. This is done because the transmission transfer capabilities are calculated using a sub-area analysis only.

Table 32 shows the summary comparison between the all the ICR Related Values and their inputs calculated for the 2018/19 FCA versus the 2017/18 FCA.

Table 32: Comparison of all ICR Related Values (MW)[43]

	New England		Connecticut		NEMA/Boston		SEMA/RI	
	2018/19 FCA	2017/18 FCA	2018/19 FCA	2017/18 FCA	2018/19 FCA	2017/18 FCA	2018/19 FCA	2017/18 FCA
Peak Load (50/50)	30,005	29,790	7,725	7,650	6,350	6,260	5,910	-
Existing Capacity Resources*	32,842	35,443	9,239	9,768	3,868	3,685	6,984	-
Installed Capacity Requirement	35,142	34,923						
NET ICR (ICR Minus HQICCs)	34,189	33,855						
1-in-5 LOLE Demand Curve capacity value	33,132	-						
1-in-87 LOLE Demand Curve capacity value	37,027	-						
Local Resource Adequacy Requirement			7,268	7,319	3,129	2,968	7,479	-
Transmission Security Requirement			7,331	7,273	3,572	3,428	7,116	-
Local Sourcing Requirement			7,331	7,319	3,572	3,428	7,479	-

[43] Existing Capacity Resources value for New England excludes HQICCs.

{ End of Report }