STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS

PUBLIC UTILITIES COMMISSION

In Re: Invenergy Thermal Development LLC	)	
Application to Construct and	)	
Operate the Clear River Energy	)	Docket 4609
Center, Burrillville, Rhode Island	)	

PREFILED TESTIMONY OF

SETH G. PARKER

Summary:

The prefiled testimony of Mr. Parker addresses specific issues identified by the Energy Facility Siting Board ("EFSB") in its Preliminary Decision and Order in case SB-2015-06 regarding the Application for the Clear River Energy Center ("CREC") submitted by Invenergy Thermal Development LLC ("Invenergy"). These issues are (i) the need for the proposed Facility, (ii) whether it is cost-justified to the consumer, and (iii) whether cost-effective efficiency and conservation ("EE&C") opportunities provide an appropriate alternative. Mr. Parker was also asked to (iv) consider whether renewable resource development would be affected by CREC and (v) review and comment on testimony submitted by the Conservation Law Foundation ("CLF") on the issues of need and costs.

Mr. Parker generally concludes that (i) CREC is needed; (ii) CREC will reduce regional wholesale capacity and energy prices but not as much as Invenergy has claimed; (iii) CREC will lower electricity costs for Rhode Island consumers; (iv) cost-effective EE&C opportunities would not be impeded and should not be viewed as an alternative; (v) renewable resource development would not be impeded; and (vi) CLF's testimony reveals fundamental misunderstandings of the regional power system, contains calculation errors, and fails to recognize how the Rhode Island Public Utilities Commission ("PUC") determines need within the context of New England's competitive power system.

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Exhibit SGP-1	Resume of Mr. Seth G. Parker

INTRODUCTION

Q. Please state your name, title, and occupation.

A. I am Seth G. Parker, a Vice President and Principal of Levitan & Associates, Inc. ("LAI"). I joined LAI in 1998. I am an economic and financial manager with 38 years of international experience in power and fuel project development, evaluation, financing, and transactions.

Q. Please summarize your professional background and experience.

A. My responsibilities at LAI include modeling and analyses of utility and non-utility power and fuel projects, competitive market design, regulatory policy, contract structuring, power plant economics, and asset valuation assignments. Prior to joining LAI, I worked as a consultant and officer of Stone & Webster Management Consultants, Inc., where I was responsible for due diligence evaluations of proposed power, fuel, and infrastructure projects in the U.S. and abroad for various financial institutions. I also worked in the Treasurer's Office at Pacific Gas & Electric, and was involved in project development and financing activities at ThermoElectron Energy Systems and J. Makowski Associates, Inc.

My educational background includes an Sc.B. in Applied Mathematics / Economics from Brown University, and an M.B.A. in Finance / Operation Research from the Wharton Graduate School at the University of Pennsylvania. I taught undergraduate-level finance as an adjunct faculty lecturer, have taken additional coursework in Basic Gas Turbine Technology and International Political Economics, and regularly lecture at two Swiss universities. My resume is provided as Exhibit SGP-1.

Q. Please describe Levitan & Associates, Inc.

A. LAI is a management consulting firm specializing in power market design, power and fuel project evaluations, pipeline infrastructure, and competitive energy economics. Since its founding in

1989, LAI has conducted numerous assignments in New England and other markets throughout the U.S. and Canada on diverse matters pertaining to generation and transmission project evaluations, wholesale energy and capacity price forecasts, retail price impacts, competitive power market design, asset valuation, bulk power security, power and fuel procurements, contract structures, gas/electric interdependencies, natural gas infrastructure, and risk management. LAI's clients include utilities, generators, Independent System Operators ("ISOs"), Regional Transmission Organizations ("RTOs"), end-users, state regulatory commissions, and financial institutions. LAI is located at 100 Summer Street, Suite 3200, Boston, MA, 02110.

Q. Have you previously testified before the Rhode Island PUC?

A. Yes. I submitted expert witness reports and testified before the PUC on power market economics pertaining to the Block Island Offshore Wind Project, including the Power Purchase Agreement with Narraganset Electric.

Q. Did you prepare this testimony yourself?

A. I personally conducted or supervised the work of LAI staff that assisted me in preparing portions of the underlying analyses in my testimony and exhibits.

Q. On whose behalf are you offering this testimony?

A. This testimony is offered on behalf of the Division of Public Utilities and Carriers ("DPUC") and the Office of Energy Resources ("OER"), which are participating in this docket before the PUC in accordance with statutory requirements.

Q. What has the PUC been asked to provide to the EFSB?

A. In its Preliminary Decision and Order in its Docket SB-2015-06, the EFSB directed that various Rhode Island agencies and government subdivisions issue advisory opinions to support a final decision regarding the CREC Application. On page 15, the PUC was directed to "...render an advisory opinion as to (i) the need for the proposed Facility; (ii) whether it is cost-justified to the

1 consumer consistent with the object of ensuring that the construction and operation of the Facility
2 will be accomplished in compliance with all of the requirements of the laws, rules, and regulations;
3 and (iii) whether cost-effective efficiency and conservation opportunities provide an appropriate
4 alternative to the proposed Facility." In addition, the PUC was also directed, on page 9, to
5 "...expressly consider...the adequacy and dependability of the natural gas supply to the facility" as
6 part of the need determination. I have been retained to assist the DPUC and OER in addressing
7 these issues on an independent basis.

8 **Q. Did the DPUC and OER also ask you to consider CREC's impact on renewable**
9 **resource development and to review and comment on testimony submitted by CLF?**

10 A. Yes, I assessed the impact of CREC on Rhode Island's renewable resource initiatives and
11 reviewed and commented on the pre-filed testimonies submitted by CLF witnesses Robert F. Fagan
12 and Christopher T. Stix.

13 **Q. Do you have particular knowledge about the Rhode Island and New England power**
14 **markets?**

15 A. Yes. I have conducted and participated in numerous economic and power market studies
16 for ISO-NE participants during my career including: (i) evaluating the feasibility of converting the
17 Salem Harbor station to natural gas; (ii) assessing the economics of the Deepwater Block Island
18 offshore wind project; (iii) supporting the purchase of the Holyoke hydroelectric station; (iv)
19 evaluating financial and power market issues of the Vermont Yankee nuclear plant; and (v)
20 forecasting wholesale power market impacts for the New England Clean Power Link, a proposed
21 1,000 MW HVDC cable to import renewable power from Canada.

22 LAI has conducted additional studies of existing and proposed generation, transmission, and
23 gas pipeline projects, environmental analyses, reliability assessments, and wholesale power
24 procurements in Rhode Island and other New England states. In many cases, these projects raise

issues of need and, if constructed, would affect the region's wholesale energy and capacity markets that are administered by ISO-New England ("ISO-NE").

Q. What is ISO-NE and what are its responsibilities?

A. ISO-NE is the independent, not-for-profit company, authorized by the Federal Energy Regulatory Commission ("FERC"), responsible for the safe and reliable operation of the bulk power system, i.e. the generating plants and the high voltage transmission network, in New England. In particular, ISO-NE: (i) administers the competitive wholesale pricing markets for energy, capacity, and ancillary services under rules and regulations established through a regional stakeholder process and approved by FERC; (ii) coordinates energy flows across the transmission network; and (iii) conducts planning studies to ensure long-term system reliability.

CREC IS NECESSARY TO MEET THE NEEDS OF RHODE ISLAND AND THE NEW ENGLAND REGION

CREC Will Help Meet Local and ISO-NE Resource Adequacy Requirements

Q. What statutory criterion did the EFSB direct the PUC to address concerning the need for CREC?

A. The EFSB defined the criterion in Issue 1 on page 9 of its Preliminary Decision and Order 86: "Is the proposed facility necessary to meet the needs of the state and/or region for energy of the type to be produced by the proposed Facility?" This criterion is taken directly from §42-98-11(b) of the Rhode Island Energy Facility Siting Act.

Q. How does the PUC determine need in this context?

A. The PUC has long recognized that the determination of need must reflect the realities of the New England power system. In its November 24, 1998 Advisory Opinion to the Energy Facility Siting Board in Docket No. 2818 regarding the Hope Energy application ("Hope Opinion"), the PUC quoted the DPUC:

> Traditionally in Rhode Island, need determinations for new electric generating facilities have been performed using measure of projected supply vis a vis demand for the utility building or purchasing power from the plant... The Commission is well aware of the new era of competitive rather than regulatory economics.
>
> In this new era, determination of need for generating plants is to be performed by the free market rather than by regulators... Even if sufficient generation exists, replacement of inefficient old plants with clean, efficient new plants may have economic as well as environmental value. Absent a gap between supply and demand, new plants may still be considered "needed" by the region. In the end, it is the market that will supply the answers...

Q. Did the PUC endorse the DPUC's view on how the need for new generating plants should be determined?

A. Yes. On the bottom of page 7 in the Hope Opinion, the PUC referred back to its November 21, 1997 Advisory Opinion to the EFSB for the Tiverton combined cycle project and noted "'obvious inconsistencies and anachronisms" between Rhode Island's Energy Facilities Siting Act ("EFSA") and the Utility Restructuring Act of 1996 ("URA")..." The Utility Restructuring Act recognizes and promotes the benefits of competition in the electricity industry. In the Hope Opinion, the PUC went on to state "...we opined that the more recently enacted URA effectively repealed by implication the much older "need" assessment provisions of the EFSA (Id.). Our opinion on this issue has not changed."

Q. On what information did you rely to address the question of whether CREC is necessary to meet the needs of the state and/or the region?

A. I reviewed the information submitted by Invenergy in its Application regarding the claimed need for CREC, prepared data requests, and reviewed Invenergy's responses to understand the claim that CREC is needed. I also reviewed and analyzed ISO-NE's methodology for determining the region's Net Installed Capacity Requirement ("NICR"), Local Sourcing Requirement ("LSR"), the sloped demand curve used in Forward Capacity Auction 10 ("FCA 10"), and the results of FCA 10 in order to evaluate CREC's potential contribution to assure resource adequacy in New England via its participation in the ISO-NE capacity market.[1]

Q. How did Invenergy support the claim that CREC is needed?

A. Invenergy supported the need for CREC by claiming that it will help modernize and replace New England's aging generation infrastructure. Among the benefits that Invenergy claimed on page 2 of its October 28, 2015 transmittal letter to the EFSB, Invenergy claimed that CREC will:

> 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.

Q. Does Invenergy claim that CREC will address market needs?

A. Yes. According to Invenergy, CREC will provide (i) capacity to help ISO-NE meet its reliability requirements and (ii) fast start and flexibility, i.e. high ramp rates, to help ISO-NE meet its operational requirements.

Q. Do you agree with Invenergy regarding the market needs and the CREC contribution to meeting them?

[1] The terms NICR and LSR are defined later on in this testimony.

1 A. In general, yes. ISO-NE procures installed capacity in the Forward Capacity Market
2 ("FCM") to ensure resource adequacy, a critical reliability requirement. One of the two CREC units
3 offered in FCA 10 cleared that auction and was assigned a year Capacity Supply Obligation ("CSO")
4 for the Capacity Commitment Period June 1, 2019 to May 31, 2020. ISO-NE is depending on the
5 first CREC unit starting on June 1, 2019.

6 In addition to providing capacity to assure resource adequacy, generating resources also
7 provide fast start, flexibility, and other performance characteristics for ISO-NE to meet its
8 operational requirements. As the electric industry and wholesale markets evolve, particularly due to
9 the growing penetration of wind power and other renewable resources, these performance
10 characteristics are becoming more important for ISO-NE's system operators to manage the New
11 England bulk power system. CREC's performance characteristics should help ISO-NE meet its
12 operational requirements.

13 **Q. How does ISO-NE determine the capacity market needs?**

14 A. Prior to every FCA, ISO-NE probabilistically calculates the NICR, i.e. the regional capacity
15 procurement target, to establish the amount of capacity needed to meet New England's reliability
16 requirements for the associated Capacity Commitment Period.[2] ISO-NE set the NICR for FCA10
17 at 34,151 MW. ISO-NE also determined if there would be any import-constrained zones within the
18 region.

19 **Q. Was Rhode Island located in an import-constrained zone?**

20 A. Yes, Rhode Island was modeled within an import-constrained zone in the last two FCAs.
21 ISO-NE modeled two Capacity Zones in FCA 10 for 2019/2020: the import-constrained

[2] ISO-NE's reliability criterion is described as the probability "...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)" on page 9 of ISO-NE's Installed Capacity Requirement, Local Sourcing Requirements and Capacity Requirement Values for the System-Wide Capacity Demand Curve for the 2019/20 Capacity Commitment Period of January 2016 ("2019/20 ICR Values Report").

1 Southeastern New England ("SENE") Capacity Zone and the Rest-of-Pool Capacity Zone.[3] SENE
2 includes Northeastern Massachusetts/Boston, and Southeastern Massachusetts/Rhode Island
3 ("SEMA/RI"). ISO-NE modeled SEMA/RI as an import-constrained zone in FCA 9 for
4 2018/2019, partly due to the announced retirement of Brayton Point. In response to that
5 announcement, transmission upgrades were planned in Rhode Island to increase SEMA/RI's import
6 capability. Those upgrades, along with the addition of new capacity resources, will relieve
7 SEMA/RI import constraints, but the combined SENE zone remains import-constrained.

8 **Q. Does capacity have a higher value in an import-constrained capacity zone than in**
9 **other zones?**

10 A. Potentially, yes. If there is insufficient capacity within the zone and the LSR becomes
11 binding at some price in the FCA, the constrained zone may clear at a capacity price higher than for
12 the rest of the ISO-NE system, providing a price signal for more investment in that zone, e.g.
13 SEMA/RI or SENE, and making qualified capacity resources such as CREC more valuable.

14 **Q. Have capacity prices in Rhode Island cleared above the rest of the ISO-NE system?**

15 A. Yes. SEMA/RI cleared at a price above the rest of the ISO-NE system in FCA 9,
16 demonstrating that capacity located in Rhode Island can be more valuable. Such high prices are
17 consistent with the competitive structure of New England's wholesale electricity markets and
18 provide signals to incentivize new investment at the appropriate location and time. Over the long
19 run, as new resource investments are made and/or demand changes, these capacity prices should
20 stabilize across the region.

21 **Q. Can ISO-NE procure capacity in excess of the NICR or LSR?**

22 A. Yes, ISO-NE can, and did, procure capacity in excess of the NICR for FCA 10. Under the
23 system-wide sloping demand curve construct, ISO-NE may clear an FCA with either an excess or a

[3] The Rest-of-Pool includes the remainder of the ISO-NE system, in this case everywhere but SENE.

deficiency of capacity compared to the NICR. ISO-NE cleared a total of 35,567 MW of capacity resources, 1,416 MW over the NICR, in FCA 10. The SENE Capacity Zone cleared 11,349 MW of resources, 1,321 MW over its LSR.

Q. Do consumers benefit from procuring more capacity than what is required for meeting the NICR reliability criterion?

A. Yes. Capacity in excess of NICR provides higher reliability for the region, which benefits consumers. For example, according to Table 4 of the ISO-NE 2019/20 ICR Values Report, if 37,053 MW had been procured in FCA 10, the reserve margin (without Hydro Quebec) would have been equal to 24.1%, which corresponds to the LOLE of 1-in-87. More capacity resources would benefit consumers by lowering the probability of blackouts and other service interruptions. The sloped demand curve construct recognizes this reliability value of such capacity. High reserve margins would probably result in lower energy prices as well, to the extent that at least some of the additional capacity have competitive operating costs. Moreover, the more capacity that clears, the lower the capacity clearing price and the total capacity cost for consumers.

Q. Has FERC recognized the reliability benefits associated with capacity procurement under the sloped demand curve construct?

A. Yes. In paragraph 30 of its Order in Docket ER-14-1639 approving the ISO-NE system-wide sloped demand curve, FERC stated:

> As to the specific parameters of the demand curve (i.e., the price cap and foot), ISO-NE has demonstrated through its Monte Carlo simulation analysis that its proposed sloped demand curve can reasonably be expected to elicit sufficient capacity to meet its stated reliability objective of a 1-in-10 LOLE on average over time. We disagree with parties that suggest that meeting the 1-in-10 LOLE standard on average over time is unjust and unreasonable and that the demand curve must be designed to meet

the 1-in-10 LOLE standard in all years... As noted above, the Filing Parties' proposal sets the reliability objective, which we accept here. [4]

In its Order, FERC accepted that the amount of procured capacity under a system-wide sloped demand curve construct may fluctuate around the NICR, so that in some years ISO-NE could have excess capacity while in others it could have a deficiency. FERC accepted that the 1-in-10 LOLE reliability criterion should be met, on average, over the long term.

Q. Does New England need all the capacity, including CREC unit 1, which cleared FCA 10 to assure reliability?

A. Yes, it does. In response to the DPUC data request ("DR") 3-9, Invenergy and its consultant PA Consulting Group, Inc. ("PA") stated that the "...system need is determined by the fulsome FCM process and not by simply procuring capacity at, or above, the NICR." They further explained that "In clearing FCA 10, by definition, the CREC was determined to be part of the most cost effective solution to meet ISO-NE's system needs."

Q. Do you agree with Invenergy and PA that all the capacity that cleared FCA 10 is needed for reliability?

A. Yes, I do. ISO-NE assigned CSOs to all of those resources, including CREC unit 1, so they are needed for reliability by definition, even capacity above the NICR that provide a positive reliability value and cost savings for New England consumers.

Q. Does the fact that SENE cleared above the LSR in FCA 10 have any impact on CREC's need determination?

A. No. The SENE LSR value represents the minimum amount of capacity needed in that capacity zone given its projected load and limited transmission import capabilities. Adding CREC

[4] LOLE is defined in footnote 2 on page 10.

1 unit 1 to the SENE resource mix enhances the reliability of SENE, Rhode Island, and the entire
2 region.

3 According to ISO-NE's methodology, the LSR is calculated as the capacity needed to satisfy
4 the higher of the Local Resource Adequacy ("LRA") requirement or the Transmission Security
5 Analysis ("TSA") requirement.[5] In FCA 10, the SENE LSR was set based on the TSA requirement,
6 which was higher than the LRA requirement. ISO-NE performed a series of deterministic studies
7 under stressed system conditions to determine the SENE TSA requirement at a level sufficient to
8 cover most reasonably anticipated events, but that does not guarantee that all of the available
9 resources located within SENE will always meet the system needs. Therefore, any resources
10 procured in excess of the SENE TSA requirement would provide needed reliability in light of
11 transmission limitations.

12 **Q. Does the fact that CREC unit 2 did not clear FCA 10 have any impact on the**
13 **determination of need?**

14 A. No. According to page 9 of PA consultant Ryan Hardy's prefiled testimony, CREC unit 2
15 will be offered in the next FCA 11. If and when CREC unit 2 clears an FCA and receives a CSO,
16 the need would be confirmed because ISO-NE would rely on it to economically meet the region's
17 reliability need. EFSB approval of the Invenergy Application would effectively allow the
18 competitive generation market, acting through the FCAs, to determine the need for CREC unit 2.
19 This would be consistent with the PUC's Hope Opinion. If CREC unit 2 does not clear, it will most
20 likely not be constructed and Rhode Island ratepayers will not bear any costs or realize any benefits.

21 **Q. Do you agree with the PA's projections that CREC unit 2 will clear FCA 11?**

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[5] According to ISO-NE's 2019/20 ICR Values Report, page 18, "The LRA is a probabilistic resource adequacy analysis of the minimum amount of capacity that needs to be located in an import-constrained zone when modeling the New England system as two zones – the zone under study and the 'Rest of New England.' 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…"

A. I do not have enough data to agree or to disagree with PA. I reviewed the PA capacity market forecast, including the projections that CREC unit 2 will clear FCA 11, but I was not provided with all the inputs and assumptions used in its proprietary model. Without this data, and the postulated supply curve in particular, it is not possible to make any definitive conclusions on PA's projection that CREC unit 2 will clear FCA 11. Moreover, FCA clearing prices are difficult to predict due to unforeseeable changes in plant technology, ISO-NE procedures, power plant development and retirements, state and federal regulations, etc. However, the chances of CREC unit 2 clearing in FCA 11 will be enhanced if it has a lower capital cost (due to avoiding costs for shared plant facilities that will be constructed for CREC unit 1) that lowers its capacity price bid.

Q. Can you offer an example of the unforeseeable changes that make it difficult to forecast FCA clearing prices?

Yes. On June 28, 2016, FERC issued an Order in Docket ER16-1434-000 accepting the ISO-NE and NEPOOL Demand Curve Design Improvements proposal to modify the sloped system demand curve used in FCAs. The straight line sloped demand curve used in FCA 10 will be replaced by a substantially different hybrid demand curve comprised of a curved segment, a horizontal segment, and a straight sloping line segment over a transitional period from FCA 11 through FCA 13. Sloped demand curves will be applied on a zonal level as well. This is a material change that will make forecasting wholesale capacity clearing prices difficult.

CREC Will Help Meet ISO-NE Operational Requirements

Q. What are ISO-NE's current and future operational challenges that need to be met by generators?

A. In 2010, ISO-NE launched the Strategic Planning Initiative ("SPI") to address threats to the reliable supply of electricity. These threats included (i) increasing reliance on natural gas as an interruptible fuel source for power plants and the consequential potential for reduced operational performance during stressed system conditions, (ii) the large number of aging, economically-challenged, oil- and coal-fired generators that provide fuel diversity to the resource mix, and (iii) greater future needs for flexible supply resources to balance the intermittent output of renewable resources. These operational challenges remain and may persist well into the future.

Q. What operational characteristics of generators are considered most valuable from the ISO-NE perspective?

A. Consistent with the SPI objectives, ISO-NE values flexibility, dependability, and diversity of its resources. If system conditions change unexpectedly and rapidly, e.g. following a contingency or an abrupt and unforeseen change in intermittent resources energy output, system operators must rely on flexible, fully dispatchable resources. These flexible resources should be capable of fast start and high ramps within a wide range of output, as well as of providing voltage and frequency control. In many cases, these operational responses must occur quickly and automatically because there is very little time for communications between the system operators and the resource operators.

In addition, ISO-NE values dual-fuel capability or other fuel arrangements that contribute to fuel assurance and can mitigate the effects of any gas transportation interruptions that may occur. Finally, ISO-NE values resources located in import-constrained capacity zones more highly than in export-constrained zones where resource output may be restricted during stressed system conditions.

Q. Does Invenergy assert that CREC will be capable of meeting such operational needs?

A. Yes, it does. According to Invenergy's October 28, 2015 transmittal letter to the EFSB, "The fast start and flexible generation capability will support the integration of new and existing renewable generation onto the power grid." Invenergy went into more detail on page 8 of its Application:

> 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. 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.

Q. Has Invenergy provided any details regarding the fast start ability of CREC?

A. Invenergy did not provide any specific information about the plant in its Application, but in its response to DPUC DR3-1, Invenergy confirmed that the CREC combined cycle units will utilize 7HA.02 gas turbines manufactured by General Electric ("GE"). Invenergy stated that the start-up time to minimum emissions compliance load, i.e. 103 MW on gas and 156 MW on oil, is 13 minutes for cold, warm, or hot starts, and that GE will contractually guarantee these start-up times.[6]

Q. Why is the particular gas turbine model important?

A. Gas turbines are at the heart of a combined cycle plant. Gas turbines burn virtually all of the fuel and generate about two-thirds of the total plant output. The exhaust from the gas turbines generates steam that in turn generates additional output from the steam turbine-generator. Thus the operating characteristics of the gas turbine selected by Invenergy are critical in determining the

[6] The minimum emissions compliance load is the minimum load at which a gas turbine can operate stably and safely while satisfying air emission limits.

1 performance of the CREC combined cycle units in the context of the ISO-NE system and CREC's
2 impact on wholesale capacity and energy prices.

3 **Q. Has Invenergy provided any details regarding the flexibility of CREC?**

4 A. In its response to DPUC DR3-1, Invenergy claimed CREC will have a ramp rate, e.g. be able
5 to increase or decrease output, by 50 MW/minute per gas turbine. I agree that this ramp rate can be
6 considered highly flexible and would help ISO-NE accommodate the variable output of the growing
7 amount of wind and solar resources in the region. Invenergy stated that GE will contractually
8 guarantee these ramp rates.

9 **Q. In summary, do you agree with Invenergy that CREC will be capable of meeting**
10 **ISO-NE's operational needs?**

11 A. Now that I know CREC will utilize GE 7HA.02 gas turbines and their performance
12 characteristics, I anticipate that CREC will be a flexible generator capable of meeting ISO-NE's
13 operational needs. As a combined-cycle generator with a very low heat rate and consuming low-cost
14 gas, I also expect it will be economically dispatched much of the time rather than being utilized as a
15 peaking or quick-start resource. Moreover, CREC will have back-up fuel oil that may be economic
16 if gas prices spike.

17 ISO-NE obtains ancillary services from resources to meet its operational needs; CREC
18 should be able to provide many of those ancillary services.[7] According to discussions with
19 Invenergy, CREC will be able to provide 30-minute operating reserves and 10-minute spinning
20 reserves, but will not be called upon to provide 10-minute non-spinning reserves. CREC will also be
21 able to provide regulation and voltage control ancillary services, but is not planning to provide

[7] ISO-NE's 2015 Annual Markets Report, May 25, 2016, discussed the following ancillary services: real-time operating reserves, forward reserves, frequency regulation, and the winter reliability program.

black-start capability.[8] Based on the available information, I agree with Invenergy that CREC will be capable of meeting many of ISO-NE's operational needs.

CREC Will Have a Reliable and Dependable Fuel Supply

Q. What is your view on the additional issue raised by the EFSB in Issue 1: "...the reliability of the resulting power...including the adequacy and dependability of the natural gas supply to the facility?

A. According to Invenergy's responses to DPUC DR3-3 through 3-5, CREC will interconnect directly to the Algonquin Gas Transmission mainline through a dedicated quarter-mile lateral that will avoid potential delivery interruptions due to constraints on the lateral. The Algonquin mainline runs from northern New Jersey through Connecticut, northwestern Rhode Island, and onward to Boston. It is one of the primary interstate pipeline systems serving New England.

CREC plans to have a three-part fuel supply: (i) gas supply and firm transportation sufficient to operate one combined cycle unit at full load; (ii) gas supply and interruptible transportation with no more than 20 days of interruptions annually to operate the second unit at full load; and (iii) two, one million gallon storage tanks for back-up fuel oil, enough to operate one unit for 72 hours at full load.

For the first unit, Invenergy proposed to obtain 75,000 Dth/day of firm supply from a marketer (or other supplier) and firm transportation through an agreement with Algonquin for deliveries to Burrillville. As an option, Invenergy proposed obtaining a firm supply and transportation from one or more marketers who hold firm transportation capacity on Algonquin. In either case, CREC unit 1 would have firm, year-round gas supply and transportation.

[8] Information provided by Invenergy during the phone call with LAI on June 7, 2016.

1 For the second unit, Invenergy believes that its firm transportation agreement with
2 Algonquin would give it "…rights to a Priority Secondary Interruptible Supply…" from Algonquin
3 for an additional 75,000 Dth/day. Invenergy explained that this is a higher level of service than
4 standard interruptible service. Alternatively, Invenergy would enter into a gas supply and
5 transportation agreement with a gas marketer with limited transportation interruptions (5 to 20 days
6 per year) based on the marketer's gas supply and transportation rights. The resulting mix of firm
7 and interruptible gas delivery arrangements, backed by onsite liquid fuel oil supplies, should provide
8 reliable fuel supplies for CREC.

9 **Q. Does Invenergy have an agreement with Algonquin that sets out the commitment to**
10 **connect the plant and provide firm transportation?**

11 A. Yes, Invenergy executed a Memorandum of Understanding ("MOU") with Algonquin that
12 lays out the general principles for Algonquin to provide firm transportation and delivery for 75,000
13 Dth/day from Ramapo, New York to Burrillville, Rhode Island, including the dedicated lateral, to
14 serve the first CREC unit. To accomplish this, Algonquin would hold an "open season" to
15 accommodate other bidders looking for firm transportation via incremental expansion on
16 Algonquin's mainline in the same time frame. The MOU is not a binding commitment but is
17 standard practice at this point in CREC's development.

18 **Q. Would the gas quantity envisioned under the MOU with Algonquin be sufficient for**
19 **one CREC unit at full load?**

20 A. In most cases, yes. Invenergy provided Predicted Unit Performance data as Exhibit 1 to its
21 response to DPUC DR3, which indicates that each CREC combined cycle unit will require the

following quantities of natural gas assuming new and clean conditions:[9] [begin confidential information]

Summer w/o duct firing	[redacted] Dth/day	
Summer w/ duct firing	[redacted] Dth/day	
Winter w/o duct firing	[redacted] Dth/day	[end confidential information]

Under typical summer conditions without duct firing, the MOU quantity should be sufficient to operate one combined cycle unit for 24 continuous hours. It would be extremely unlikely for CREC to operate at full load with duct firing for a 24 hour period in summer months. It would also be unlikely that CREC would operate at full load for a 24 hour period winter months. Therefore the MOU quantity should be sufficient under virtually all conditions.[10]

Q. Would CREC be dependent upon expansions to the Algonquin mainline being completed in time?

A. Yes. Invenergy's first firm supply and transportation option assumes Algonquin conducts an open season process for an expansion on its mainline. This process would be subject to a FERC certification process and the expansion would require state and local construction permits. Such open season processes occur regularly and should not be problematic for relatively small expansions such as this.

Under Invenergy's second option for firm supply and transportation in which Invenergy made arrangements with marketers holding firm transportation capacity rights on the Algonquin system, this open season process would be avoided. For example, Invenergy could enter into a gas management arrangement where the counterparty would release firm transportation capacity in the

[9] ISO-NE is a summer-peaking system, so duct firing would be much more likely during summer months than winter months. Hence the Unit Performance data provided by Invenergy did not include winter operations with duct firing.
[10] Degradation over time results in lower fuel requirements, so is not an issue.

1 secondary market. Some of that capacity could be dependent on other pipeline expansion projects
2 currently being developed by Algonquin:

3 (i) The Algonquin Incremental Market ("AIM") project will increase deliveries into New
4 England by 342,000 Dth/day. AIM has received all of its permits and approvals, is under
5 construction, and is expected to be completed later this year.
6
7 (ii) The Atlantic Bridge ("AB") project is proposed to increase deliveries through New
8 England and into the Canadian Maritimes by a further 132,700 Dth/day. AB is still under
9 development and is making progress. On May 2, 2016, FERC issued an Environmental
10 Assessment that determined AB would not cause any significant harm, a key step in
11 receiving its FERC certificate, which is expected later this year. Algonquin expects AB to be
12 completed by November 2017.
13
14 **Q. Please clarify how the Algonquin open season expansion differs from the AIM and**
15 **AB projects.**
16 A. In order for Invenergy to obtain the firm gas transportation as described in the MOU,
17 Algonquin would hold an open season for expanding its mainline in which Invenergy would bid for
18 75,000 Dth/day. This open season expansion is separate from the AIM and AB expansion projects
19 that are fully subscribed, i.e. gas utilities and other shippers have already entered into agreements for
20 all of the firm transportation capacity that was offered.
21 **Q. Could the utilities, marketers, and other shippers holding firm transportation**
22 **capacity on the AIM and AB projects release some of that capacity?**
23 A. Yes, they could release some of their capacity on a firm basis or subject to recalls, i.e.
24 interruptions, during the winter months. In the event of an interruption, Invenergy would have to
25 utilize a portion of its two million gallons of back-up fuel oil to ensure both CREC units could
26 operate.

Q. Is Invenergy's claim that interruptible transportation would be limited to 5 to 20 days per year an advantage compared to other interruptible arrangements?

A. Yes. The Algonquin mainline is heavily utilized and can have much more than 20 days of interruptions during winters with long, very cold conditions. Invenergy's proposed transportation arrangement is designed to limit CREC's exposure to interruptions to no more than 5 to 20 days.

Q. Is CREC's fuel storage tank plan reasonable and appropriate for a reliable and dependable fuel supply?

A. Yes. CREC will include two tanks, each holding one million gallons of ultra-low sulfur diesel fuel oil, that Invenergy claimed should be sufficient to operate one combined cycle unit for 72 hours. I have confirmed that two full tanks would be sufficient for at least 72 of operation utilizing Invenergy's Unit Performance data during winter months.

Q. What is ISO-NE's Pay-for-Performance construct, and will CREC's back-up fuel supply enable it to meet those requirements?

A. After an extended cold spell in January, 2014, ISO-NE became concerned that capacity resources were not performing adequately to ensure system reliability during scarcity conditions, i.e. when there is insufficient energy and reserves. Gas transportation interruptions were a particular problem as pipelines served their customers who had firm transportation rights. To address this problem, ISO-NE proposed and FERC accepted the Pay-for-Performance construct to provide financial incentives under a two-settlement capacity payment structure to reward capacity resources that provide energy and reserves during scarcity conditions. Having a back-up fuel oil supply should enable CREC to provide energy and reserves in such conditions and thus be eligible for the additional capacity payments. Pay-for-Performance is expected to be in effect on March 15, 2018.[11]

[11] http://www.iso-ne.com/static-assets/documents/2015/09/er15-2208-000.pdf.

CREC IS COST-JUSTIFIED AND WILL PROVIDE ECONOMIC BENEFITS

CREC is Cost-Justified and Will Be a Low Cost Producer

Q. What statutory criterion did the EFSB direct the PUC to address concerning CREC's cost of capacity and energy?

A. The EFSB defined Issue 2 on page 9 of its Preliminary Decision and Order 86: "Is the proposed facility (A) cost-justified and can it be expected to produce energy at the lowest reasonable cost to the consumer…" This criterion, taken from §42-98-11(b) of the EFSA, must be understood in the context of New England's deregulated and competitive generation market as I explained earlier.[12] Parenthetically, while both the EFSA and the EFSB's Preliminary Decision and Order 86 refer only to energy, I interpreted the criteria to include capacity as well as energy. In any event, Invenergy did not address these criteria directly in its Application.

Q. Is the cost-justified criterion appropriate in New England's deregulated and competitive generation market?

A. No, not since the regional power industry was restructured. With few exceptions, generators in New England are merchant plants and not owned by utilities; their costs and risks are not directly borne by ratepayers. Merchant generators, such as the proposed CREC, must compete in the ISO-NE's competitive power markets. Ratepayers only pay for capacity and energy that ISO-NE determines to be cost-effective through its wholesale procurement and pricing mechanisms.

The competitive power market here in New England will determine whether CREC is cost-justified. If its capacity and energy bids are accepted, CREC will provide and be paid for those products, effectively determining that CREC is cost-justified. If Invenergy believes that projected

[12] The PUC explicitly recognized this in the Hope Opinion, understanding that the EFSA was enacted prior to electric utility restructuring in New England and prior to Rhode Island's Utility Restructuring Act.

1 revenues will be sufficient to cover CREC's operating costs and allow it to recover its investment
2 costs, CREC will be built. If Invenergy believes its revenues will not be sufficient, CREC will not be
3 built. In either event, Invenergy, not Rhode Island consumers, will be at risk.

4 **Q. Why is the lowest reasonable cost criterion not appropriate in New England's**
5 **deregulated and competitive generation market?**

6 A. Generating plants with different technologies typically have different cost structures, e.g.
7 capital cost, fixed operating expenses, and variable operating expenses, yet all of these plants may be
8 considered cost-justified because of their particular attributes, e.g. flexibility, quick start capability,
9 reliability, fuel, and price stability, and the needs of the power systems in which they operate. For
10 example, a gas-fired combined cycle plant (such as CREC) could provide responsive performance
11 and low energy costs (assuming low gas costs) while wind projects may have higher capital costs but
12 lower operating costs and zero emissions. A simplistic criterion of lowest reasonable cost fails to
13 account for all of these factors.

14 **Q. Did Invenergy directly address these criteria or provide another argument to support**
15 **its request for EFSB approval?**

16 A. Invenergy neither explicitly claimed that CREC is cost-justified nor would produce capacity
17 and energy at the lowest reasonable cost. Instead, in its Application and in the prefiled testimony of
18 Ryan Hardy, Invenergy claimed that CREC would lower wholesale capacity and energy prices in
19 New England and that Rhode Island consumers would benefit from these lower prices. The
20 Application also claimed that CREC's operational characteristics would be beneficial to the region as
21 more wind resources are developed. Those operational benefits were addressed earlier in my
22 testimony.

23 **Q. Will CREC be a low cost generator in New England?**

1 A. Yes. First, I agree with Invenergy's claim on page 6 of its Application that CREC will
2 "...provide new, highly advanced generating technology that will be one of the most efficient
3 generators in New England..." This claim is supported by Invenergy's selection of GE 7HA.02 gas
4 turbines, consistent with Hardy Exhibit RH-3 (the PA energy memo of April 22, 2016). A
5 combined cycle plant utilizing such H-class gas turbines will be more efficient than most existing
6 generation plants in New England. Second, an efficient plant that burns natural gas (that itself is
7 relatively inexpensive in most hours of the year) should make CREC a low-cost generator in this
8 region. Plus, as I mentioned earlier, the back-up fuel oil will mitigate occasional gas price spikes
9 should they occur.
10
11 **Rhode Island Consumers Will Benefit from Lower Wholesale Capacity and Energy Prices**
12
13 **Q. How did you evaluate Invenergy's claims that CREC would lower wholesale capacity**
14 **and energy prices in New England and Rhode Island consumers would benefit from such**
15 **lower prices?**
16 A. I reviewed the information submitted by Invenergy with the estimated capacity and energy
17 savings for Rhode Island consumers and prepared data requests and reviewed Invenergy's
18 responses. It appears that the assumptions and calculations of capacity and energy savings were
19 entirely prepared by Invenergy's consultants, PA.
20 **Q. Did you conduct an independent estimate of reduced wholesale capacity and energy**
21 **prices?**
22 A. No, it was decided that I should analyze the estimates PA prepared for Invenergy, identify
23 strengths and weaknesses in those calculations, and render an opinion for the PUC.
24 **Q. Please describe Invenergy's initial estimate of the capacity and energy cost savings.**

A. On page 119 of its Application, Invenergy estimated "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." This initial estimate was prepared by PA, which forecasted wholesale capacity and energy prices for New England under two scenarios, with and without CREC beginning June 1, 2019, and then compared those results to estimate CREC's impact on wholesale capacity and energy prices. PA claimed:

> The additional CREC capacity would 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 resources. Thereafter, Rhode Island ratepayers would continue to realize approximately $23 million in energy cost savings per year, with capacity cost impacts...determined by the types of new development capacity that enter the ISO-NE market to maintain reliability after Clear River's market entry.

Q. What support did Invenergy provide for its initial estimate of the capacity and energy cost savings?

A. The Application included two PA memos as Supplemental Exhibits to support these estimates, but they do not accomplish this. The first memo of July 29, 2015 described PA's methodology for forecasting capacity prices and how the forecasted capacity price for FCA 10 compared to the actual capacity price for FCA 9. However, it did not sufficiently explain how PA calculated the expected decline in wholesale capacity prices due to CREC. The second memo of June 16, 2015 summarized PA's general methodology for forecasting wholesale energy prices and presented its projection of CREC's energy revenues. It also did not sufficiently explain how PA calculated the expected decline in wholesale energy prices due to CREC.

Q. According to Mr. Hardy's testimony, will CREC's output be 850-1,000 MW as stated in the Application?

1 A. It appears that CREC output will be at the upper end of this range. According to plant data
2 provided with Invenergy's response to DPUC DR3-1, the net plant output (with both combined
3 cycle units after internal plant uses and losses) will be [redacted] MW [confidential] firing on gas during the
4 summer months. In addition, the combined cycle units will be able to burn an additional quantity of
5 gas in the heat recovery steam generator (referred to as duct firing) to increase steam production and
6 net plant output to [redacted] MW [confidential] in the summer months. During the winter months, the
7 net plant output will be [redacted] MW on gas and [redacted] MW on oil.[confidential]
8 These output values are based on CREC being in "new and clean" condition, before any
9 degradation takes place. Plant performance values are often provided this way, especially for design
10 and contract performance purposes. Consistent with Invenergy's response to DPUC DR3-1,
11 degradation will naturally occur over time and reduce plant output and efficiency. Periodic major
12 maintenance will restore plant output and efficiency close to the original new and clean values.
13 Even with average degradation, I expect the CREC output to be at the upper end of the output
14 range in the Application.
15 **Q. Please describe how wholesale capacity and energy prices are determined in New**
16 **England.**
17 A. Prices for capacity and energy, New England's two most important wholesale power
18 products, are set by ISO-NE under FERC-approved competitive pricing mechanisms. Capacity is
19 the ability of generation resources to produce energy when needed to meet consumer demand;
20 demand-side resources accomplish the same goal by reducing consumer demand. Energy is the
21 actual electricity generated and delivered to consumers to meet their demand. These products are
22 procured in the ISO-NE wholesale markets for ultimate retail sale by utilities and other load-serving
23 entities.

1 Wholesale capacity prices are set annually three years in advance via FCAs administered by
2 ISO-NE. All generators that clear in the FCA, i.e. whose offers are selected by ISO-NE, are
3 awarded CSOs that obligate them to submit daily energy offers in the Capacity Commitment Period
4 three years hence.[13] The capacity revenues paid to generators are a function of the wholesale
5 capacity price set in the FCA, the resource's capacity, and the resource's performance in that future
6 Capacity Commitment Period.
7 Wholesale energy prices are primarily set daily in ISO-NE's Day-Ahead Market.[14]
8 Generators submit hourly energy bids and are paid for the energy they deliver in each hour in which
9 they are dispatched by ISO-NE. These wholesale capacity and energy prices are locational in that
10 they may differ throughout New England to reflect transmission and other operational constraints.
11 **Q. How would changes in wholesale capacity and energy prices affect Rhode Island**
12 **consumers?**
13 A. ISO-NE collects monies from utilities and other load-serving entities in New England to pay
14 generators and other capacity resources for capacity and energy. Thus every consumer's bill includes
15 a portion of ISO-NE's wholesale capacity and energy costs.[15] Rhode Island consumers pay their
16 share of the wholesale energy and capacity costs based on their usage.
17 **Q. Did Invenergy revise its initial estimated reductions in wholesale capacity and**
18 **energy costs?**
19 A. Yes, Invenergy submitted prefiled testimony of Ryan Hardy of PA on April 22, 2016, who
20 revised the initial estimates in light of an expected delay in the second CREC unit from June 1, 2019

[13] Under ISO-NE rules, existing capacity resources submit "bids" and proposed resources submit "offers" in FCAs; I have tried but may not have always used these terms accurately in my testimony.

[14] ISO-NE also operates a Real Time Market for energy that continuously balances supply and demand, but those payments to generators are a fraction of the Day-Ahead energy payments.

[15] Consumer bills also include ISO-NE ancillary service costs and retail costs for delivery via the local distribution system and other local utility services.

1 to June 1, 2020 due to its failure to be selected in ISO-NE's FCA 10. Mr. Hardy revised the
2 forecasted capacity cost savings downward from $220 million to $170 million and the energy cost
3 savings downward from $65 million to $41 million. Mr. Hardy also provided revised PA memos as
4 Exhibits RH-2 and RH-3 that updated the PA memos provided with the Application.
5
6 **Invenergy Exaggerated the Capacity Cost Reduction Benefit**
7
8 **Q. Please specify Invenergy's updated estimate of capacity cost savings due to CREC.**
9 A. In his prefiled testimony that included Invenergy's updated estimate of capacity cost savings
10 due to CREC, PA consultant Ryan Hardy estimated the savings to be $170 million in total over four
11 Capacity Commitment Periods, June 1, 2019- May 31, 2023.[16] He provided Exhibit RH-2 to support
12 his estimate. Additional confidential supporting materials were presented in response to DPUC
13 DR2-1.
14 **Q. Does Mr. Hardy's memo, Exhibit RH-2, support PA's estimated capacity cost**
15 **savings due to CREC?**
16 A. No. This memo duplicated PA's July 29, 2015 memo in the Application that described its
17 methodology for forecasting wholesale capacity prices and added a brief review of FCA 10 results
18 along with an outlook for FCA 11. This memo noted that the actual FCA 10 capacity price was very
19 close to PA's forecast in its July 29, 2015 memo included with the Application. However, as with
20 the original July 29, 2015 memo, Mr. Hardy's memo provided very little useful information
21 describing how wholesale capacity prices decline due to CREC, so it does not support Invenergy's
22 estimated capacity cost savings for Rhode Island consumers.

[16] A Capacity Commitment Period, June 1 through May 31 of the following year, is the annual period for which ISO-NE awards CSOs.

Q. In light of the lack of support for Invenergy's estimate of capacity cost savings for Rhode Island consumers, how did you assess the reasonableness of the estimate?

A. I prepared three sets of data requests for Invenergy that provided answers to some of our questions. In response to our first set of data requests, Invenergy provided a spreadsheet that summarized the change in wholesale capacity prices due to CERC for the period 2019-2022 and how much Rhode Island consumers would pay. In response to more detailed questions in our second set of data requests, Invenergy provided more information about its capacity pricing methodology. Although PA was unwilling to provide certain information because of confidentiality concerns, I spoke to Mr. Hardy and other PA consultants who furthered my understanding of their methodology. I also reviewed data requests submitted by other participants and Invenergy's responses.

Q. What was Invenergy's estimate of the reduction in wholesale capacity costs due to CREC?

A. Mr. Hardy estimated that CREC unit 1 reduced FCA 10 wholesale capacity prices by [redacted]/kW-month [confidential] for the 2019/20 Capacity Commitment Period, and CREC unit 2 would reduce FCA 11 wholesale capacity prices by [redacted]/kW-month [confidential], as summarized in Table 1 below. [begin confidential information]

Table 1. Rhode Island Wholesale Capacity Prices ($/kW-month)

FCA	Commitment Period	Without CREC	With CREC	Reduction due to CREC
FCA 10	2019/20	[redacted]	[redacted]	[redacted]
FCA 11	2020/21	[redacted]	[redacted]	[redacted]
FCA 12	2021/22	[redacted]	[redacted]	[redacted]
FCA 13	2022/23	[redacted]	[redacted]	[redacted]

[end confidential information]

1 **Q. Was PA's assumption that the capacity savings will occur over a four-year period of**
2 **time reasonable?**
3 A. Yes. In Invenergy's response to DPUC DR2-1, Invenergy provided values for 2019-2022
4 that indicate virtually all of the wholesale capacity cost reduction would occur during the first four
5 years of operation. On page 119 of its Application, Invenergy alluded to the fact that future capacity
6 development after CREC becomes operational would affect the persistence of the wholesale
7 capacity cost reduction, i.e. the capacity price reduction will cease once the ISO-NE capacity market
8 "rebalances" with CREC. This is a reasonable assumption.
9 **Q. Was PA's methodology for calculating the reduction in wholesale capacity prices**
10 **reasonable?**
11 A. For the most part, yes. PA essentially simulated the FCA pricing mechanism by starting with
12 previous FCA results, adding in new offers based on their net revenue requirements, and removing
13 resources that have announced their retirement. This is a reasonable approach.
14 **Q. Are PA's estimated reductions in wholesale capacity prices reasonable?**
15 A. I believe that PA's estimates are exaggerated. First, PA explained that it assumed a vertical
16 capacity supply curve in the region where it crosses the demand curve.[17] ISO-NE does not reveal
17 supply offer data or illustrate the FCA supply curves that are made up of these confidential offers,
18 so it is not easy to reconstruct the actual supply curve slope. By assuming a vertical supply curve,
19 however, PA maximized the capacity price reduction, $1.55/kW-month, due to CREC unit 1. If the
20 supply curve was sloped in the region where it intersected the demand curve, the capacity price
21 reduction would necessarily be lower. At the other extreme, a horizontal supply curve segment
22 would result in CREC unit 1 having virtually no impact on the FCA 10 clearing price. As I discuss

[17] Conference call between LAI and PA on May 12, 2016.

later in my testimony, I suggest that neither of the two extreme cases should be relied upon in determining the capacity price reduction attributable to CREC unit 1.

Second, ISO-NE explained that by accepting a non-rationable capacity resource, i.e. a resource whose entire offer quantity must be accepted, in FCA 10, ISO-NE had to reject a set of less expensive (under $7.03/kW-mo) offers that would not have provided enough capacity to allow the supply curve to intersect with the demand curve without CREC unit 1. With CREC unit 1, however, they would have increased the excess of capacity, so ISO-NE rejected them.[18] Without CREC unit 1, some or all of those rejected resources would have cleared and the FCA 10 capacity clearing price would likely have been higher than $7.03/kW-month. As a result, the savings due to CREC unit 1 would have been lower than estimated by PA.

Third, PA did not explain how CREC could cause a wholesale capacity price reduction of [confidential] [redacted]/kW-month in FCA 11, more than double the reduction of [confidential] [redacted]/kW-month in FCA 10. PA must have again assumed a vertical supply curve in the range where it intersects with the demand curve, which would maximizing impact of CREC in FCA 11. PA's [confidential] [redacted]/kW-month price reduction could only be possible if the price-setting alternative resource (absent CREC) would be offered at a price of [confidential] [redacted]/kW-month (see Table 1 above). However, there would likely be some new resources that would fill the CREC gap of 970 MW at a lower price. PA's implicit assumption that only CREC could offer at [confidential] [redacted]/kW-month and all other new resources would offer at a much higher price is unrealistic.

Fourth, CREC unit 2 may not clear FCA 11, particularly if the clearing price is lower than the FCA 10 price. In this case, the capacity benefits attributable to CREC unit 2 will be delayed until it clears a future FCA.

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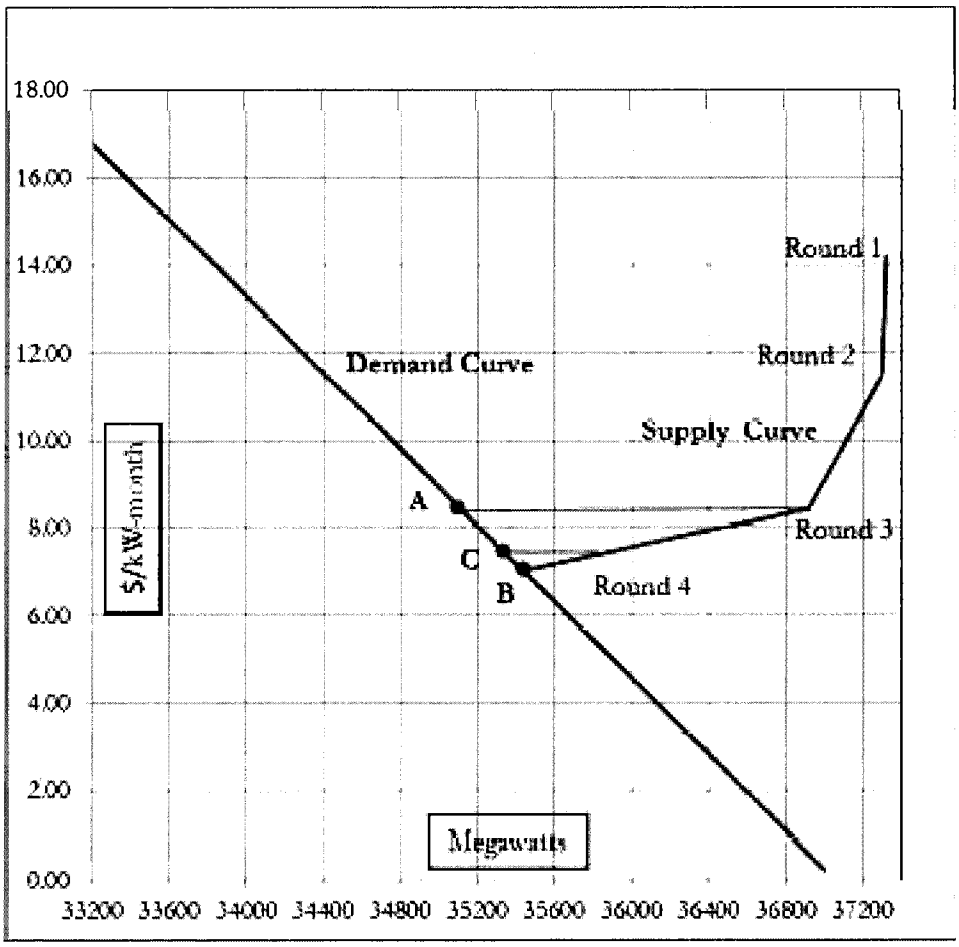
[18] This is described in more detail on page 8 of Robert Ethier's testimony, Attachment C in FCA 10 Results in FERC Docket ER16-1041.

Q. Regarding your first criticism, what makes you believe that the supply curve is not vertical?

A. I have plotted the descending clock auction data ISO-NE provided for FCA 10 in the ISO-NE's Forward Capacity Auction Results Filing in FERC Docket ER16-1041 dated February 11, 2016 ("FCA 10 Results"), i.e. the capacity prices and quantities remaining at the end of the first four auction rounds. As you can see from Figure 1 below, the portion of the supply curve lying above the demand curve has a slope that is neither flat nor vertical. I note, however, that ISO-NE does not provide data for the alternative resource offers that have dropped out in the last round when the price was declining from $8.50/kW-mo; therefore I cannot reconstruct the supply curve with complete accuracy.

Figure 1. FCA 10 Demand and Supply Curves



Q. How did you utilize this data to check PA's estimated capacity price reduction for FCA 10?

A. I performed the following steps to analyze PA's estimated capacity price reduction for FCA 10. First, PA estimated that without CREC unit 1, FCA 10 would have cleared at [confidential] [redacted]/kW-month, a reduction of $1.55/kW-month, but this would not have been possible now that we know the third round of FCA 10 ended at $8.50/kW-month. At most, the savings due to CREC unit 1 would be based on the difference between the prices of Points A ($8.50/kW-mo) and B ($7.03/kW-mo), or $1.47/kW-month.

Second, if CREC unit 1 had not been offered, some of the resources that dropped out in the last round would have stayed in the auction and FCA 10 would have cleared at some price in the range between Point A ($8.50/kW-month with 1,733 MW of excess capacity) after round 3 and Point B ($7.03/kW-month) after round 4. Without CREC unit 1, the FCA 10 supply curve would have shifted to the left by 485 MW and the market would have cleared somewhere between Point A and Point B. Since 485 MW is less than one-third of the excess capacity after round 3, it is reasonable to believe that FCA 10 would have cleared closer to the bottom end of the range, i.e. closer to $7.03/kW-month. The resulting price is illustrated by Point C in Figure 1.

Third, capacity that was rejected due to CREC unit 1 would have stayed in FCA 10, shifting the supply curve to the right and further lowering the clearing price. The net effect of my analysis is that the actual wholesale capacity benefit for Rhode Island consumers for FCA 10 is likely around one-quarter to one-half of PA's estimate.

Q. Were you able to analyze PA's estimated capacity price reduction for FCAs 11 – 13?

A. No, I could not without detailed modeling data from PA and ISO-NE's parameters for those future auctions that have not yet been established.

1 **Q. In summary, is the PA estimate of capacity cost savings due to CREC reasonable?**

2 A. My criticisms of PA's approach, e.g. assuming a vertical supply curve that maximizes the
3 wholesale capacity price reduction, applies to PA's total wholesale capacity savings estimate of $170
4 million for 2019-2022. I cannot tell if the actual savings would be one-quarter to one-half of PA's
5 total savings estimate, per my analysis of FCA 10. In summary, I believe the actual wholesale
6 capacity savings would be less than PA estimated, but would still provide a material savings for
7 Rhode Island consumers. Importantly, while the PUC has been presented with a range of potential
8 capacity savings stemming from CREC, it must be recognized that *any* savings ultimately realized as
9 a result of constructing CREC will accrue to consumers without shifting investment risk on to them.
10 This is a key benefit of utility restructuring and competitive wholesale markets, which Rhode Island
11 adopted through its Utility Restructuring Act of 1996.

12

13 **Invenergy's Estimated Energy Cost Reduction Appears Reasonable**

14

15 **Q. Please confirm Invenergy's updated estimate of energy cost savings due to CREC.**

16 A. In his prefiled testimony, PA consultant Ryan Hardy estimated the savings to be $41 million
17 over the four years 2019-2022. He provided Exhibit RH-3 to support his updated estimate.

18 **Q. Does the PA memo Exhibit RH-3 support PA's updated estimate of energy cost**
19 **savings due to CREC?**

20 A. No. Exhibit RH-3 duplicated most of PA's original June 16, 2015 memo in the Application
21 that described its methodology for forecasting wholesale energy prices. It also updated PA's
22 projection of CREC's energy revenues, but as with the original memo, Exhibit RH-3 did not provide
23 any useful information describing how wholesale energy prices decline with CREC. Thus it does
24 not support Invenergy's updated estimated energy cost savings for Rhode Island consumers.

Q. In light of Exhibit RH-3 not supporting Invenergy's estimate of the reduction in wholesale energy prices, how did you assess the reasonableness of the estimate?

A. I prepared data requests for Invenergy that provided answers to this and other questions. I also reviewed data requests submitted by other participants and Invenergy's responses.

Q. Did Invenergy provide a more detailed estimate of the reduction in wholesale energy costs due to CREC?

A. Yes. Based on the data provided in response to DPUC DR2-1, Invenergy estimates that CREC unit 1 will reduce wholesale energy prices by an average of [confidential] [redacted]/MWh for the seven month period June-December 2019 and more in succeeding years, assuming CREC Unit 2 becomes operational in June of 2020, as summarized in Table 2 below. [begin confidential information]

Table 2. Rhode Island Wholesale Energy Prices ($/MWh)

Calendar Year	Without CREC	With CREC	Reduction due to CREC
2019	[redacted]	[redacted]	[redacted]
2020	[redacted]	[redacted]	[redacted]
2021	[redacted]	[redacted]	[redacted]
2022	[redacted]	[redacted]	[redacted]

[end confidential information]

Q. Is the four-year period in which Mr. Hardy estimated wholesale energy price reductions the same four-year period for his estimated wholesale capacity price reductions?

A. Not exactly. Mr. Hardy's wholesale capacity price calculations were over a four-year period of June 1, 2019 through May 31, 2023. However, his wholesale energy price calculations were over a three and one-half year period of June 1, 2019 through December 31, 2022. This is a minor discrepancy.

Q. Will Rhode Island consumers benefit from reduced wholesale energy costs beyond 2022?

A. Yes. Unlike the capacity market that will rebalance after a few years, I would expect that CREC will displace higher cost and less efficient generation resources for many years due to its high efficiency relative to other power plants in the ISO-NE system.

Q. Were PA's methodology and key modeling assumptions for calculating the reduction in wholesale energy prices reasonable?

A. Yes. According to the PA memo provided as Exhibit RH-3, PA utilized an industry-standard chronological dispatch simulation model, AURORAxmp, to forecast hourly energy prices with and without CREC. LAI utilizes the same model and finds it to be reliable. The key assumptions specified in Exhibit RH-3 regarding market structure, fuel prices, environmental regulations, supply and demand forecasts, the cost and performance of new entry, and transmission all appear to be reasonable.[19] While there are many other assumptions that go into an energy price forecast, I am satisfied that the key assumptions in Exhibit RH-3 are reasonable. Moreover, since the goal of this forecast is the change in wholesale energy prices, rather than the absolute price, any small disagreement in these assumptions would not be critical.

Invenergy's Claim CREC Will Reduce Electricity Costs for Rhode Island Consumers Is Vague But the Savings Should Be Meaningful

[19] PA assumed all future combined cycle plants would have heat rates typical of F-class gas turbines, i.e. be less efficient, than CREC's H-class gas turbines, thereby maintaining CREC's operating cost advantage throughout PA's 20-year forecast. This is not significant in this docket because Invenergy presented estimated wholesale energy savings for only four years.

1 **Q. Did you review Invenergy's related claim on page 8 of the Application that "Rhode**
2 **Island ranks 7th highest in average price of electricity to end-use customers in the nation"**
3 **and "CREC is expected to result in a reduction of electricity prices for end-use customers"?**
4 A. Yes. I briefly reviewed Invenergy's claim and generally agree that Rhode Island has high
5 electricity costs. According to data presented by the US Energy Information Agency, Rhode Island
6 had the 9th highest average cost in 2013 and the 5th highest average cost in 2014. However, I found
7 Invenergy's claim to be somewhat vague. First, the price of electricity for Rhode Island consumers
8 shown in Table 3.2-1 of the Application includes wholesale and retail costs. As I explained
9 throughout my testimony, CREC will lower wholesale capacity and energy costs somewhat, but will
10 not affect the retail portion of consumer bills. Second, Invenergy did not estimate how much the
11 average electricity price will go down for consumers, so it is difficult to assess how Rhode Island's
12 ranking will be impacted by CREC.
13 **Q. Did you try to estimate the significance of the consumer savings due to CREC?**
14 A. Yes, in a very rough fashion. The US Energy Information Administration reported that total
15 electricity sales to Rhode Island consumers were $1.3 billion in 2015.[20] In his prefiled testimony, Mr.
16 Hardy estimated that CREC would provide $210 million in savings over four years, or about $52
17 million per year in 2019-2022. Ignoring the difference in timing, that dollar savings represents about
18 a 4% savings for consumers. When adjusted to reflect PA's exaggerated wholesale capacity price
19 savings and the likely growth in the dollar value of electricity sales as higher gas prices drive up
20 wholesale energy prices, the percentage savings for Rhode Island consumers would be small but
21 meaningful.

[20] Electric Power Monthly, February 2016, Table 5.5.B.

Q. Will the consumer savings occur "…under a wide range of reasonable factual assumptions involving the types and costs of fuel to be used" as directed by the EFSB on page 10 of its Preliminary Decision and Order in its Docket SB-2015-06?

A. Yes. The range of expected delivered gas prices is relatively narrow over the next few years due to continued shale gas production, and there's no evidence that CREC's fuel plan will change. Rhode Island consumers should benefit from a small but meaningful reduction in wholesale capacity and energy costs under any reasonable set of fuel assumptions.

CREC WILL NOT IMPEDE COST-EFFECTIVE ENERGY EFFICIENCY, CONSERVATION, OR RENEWABLE RESOURCE ALTERNATIVES

Q. What criteria did the EFSB direct the PUC to address concerning EE&C alternatives?

A. In its instructions to non-jurisdictional agencies, the EFSB requested the PUC to opine on "…whether cost effective efficiency and conservation opportunities provide an appropriate alternative to the proposed Facility."

Q. What are Rhode Island's long term EE&C goals?

A. The Rhode Island State Planning Council formally adopted Energy 2035 - Rhode Island State Energy Plan ("Energy 2035") that describes proposed policies to maximize energy efficiency in order to "…achieve its vision of a secure, cost-effective, and sustainable energy future" by achieving a number of consistent long term goals. EE&C is critical, according to page 60 of Energy 2035:

> Energy efficiency is the state's centerpiece policy for achieving the Energy 2035 Vision. The state is already a nationally recognized leader in energy efficiency, due to its "Least-Cost Procurement" mandate for electric and natural gas resource acquisition planning. Least-Cost Procurement ensures that Rhode Island maximizes

the use of the lowest-risk, lowest-cost, and arguably most sustainable energy resource available: energy efficiency.

As Rhode Island looks ahead to 2035, the State should reaffirm its commitment to leadership in energy efficiency by instituting an economy-wide, all-fuels approach to least-cost resource acquisition. To begin with, Rhode Island should continue securing all cost-effective electric and natural gas energy efficiency by renewing the existing Least-Cost Procurement mandate past 2018.

Q. Was Least-Cost Procurement extended past 2018?

A. Yes, the Rhode Island General Assembly extended it to 2024 during the 2015 legislative session.

Q. How did Invenergy address this issue of EE&C alternatives?

A. In section 8.0, Conformance with Rhode Island Energy Policy on page 122 of its Application, Invenergy claimed that CREC is "…fully in conformance with Rhode Island Energy Policy" as defined by Energy 2035:

> 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.

Invenergy addressed the question of whether cost-effective EE&C opportunities provide an appropriate alternative more directly in section 10.1.2, Renewable Technology Alternatives, on page 128 of its Application. Invenergy described renewable resource as well as EE&C alternatives, and highlighted Rhode Island's leadership in end user EE. However, Invenergy stated that 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…" given potential plant retirements and load growth.

Q. Does Rhode Island have a statutory requirement for implementing cost-effective EE&C programs?

A. Yes. Rhode Island's Comprehensive Energy Conservation, Efficiency, and Affordability Act of 2006 (General Law §39-1-27.7) established the state's landmark "Least-Cost Procurement" policy. According to page 78 of Energy 2035:

> The Act created a groundbreaking mandate termed "Least-Cost Procurement" – a policy that requires Rhode Island electric and natural gas distribution companies to invest in all cost-effective energy efficiency before the acquisition of additional supply. This strategy is "least-cost" because energy-saving measures—such as higher-efficiency lighting, HVAC systems, and appliances; insulation; air sealing—cost approximately 4 cents per kWh over their lifetime while electric supply costs between 8 cents and 12 cents per kWh.

Q. Is there evidence that Rhode Island electric utilities are implementing cost-effective EE&C programs?

A. Yes. National Grid, the principal electric utility serving Rhode Island, has been implementing cost-effective EE&C measures to satisfy the PUC's Least-Cost Procurement requirements in the Three-Year Energy Efficiency Procurement Plan for 2015-2017 per Order 21781 issued in Docket 4522 on December 19, 2014. Under Least-Cost Procurement, annual electric and natural gas energy efficiency programs are developed to achieve the full economic potential of cost-effective demand-side load reductions. National Grid filed its most recent Energy Efficiency Program Plan for 2016 with the PUC in Docket 4580 on October 15, 2015, in which it proposed to invest $87.5 million for electric EE&C. According to that document, National Grid expected each $1 of costs to provide $1.77 in benefits for Rhode Island consumers, and "The

electric plans are expected to produce lifetime savings of 1,792,431 MWh, which translates into lifetime bill savings of approximately $320 million."

Q. Does ISO-NE account for planned Rhode Island's EE&C programs?

A. Yes. ISO-NE makes Passive Demand Resources, i.e. EE, adjustments to its long-term load forecast in its system planning studies and incorporates the results in the annual Capacity, Energy, Loads, and Transmission ("CELT") and Regional System Plan reports. The 10 year EE forecast is developed by ISO-NE based on the projected budgets of state-sponsored EE programs.

Q. What are the projected levels of EE penetration in Rhode Island for the next 10 years?

A. According to the 2016 Energy-Efficiency Forecast 2020-2025 developed by ISO-NE, EE programs in Rhode Island will reduce summer peak loads by 110 MW and have 747 GWh in cumulative energy savings over the period from 2020 through 2025. These projections are incremental to the near-term (through 2019) EE projections that are based on the CSOs assigned to the EE resources in the FCM.

Q. Are Rhode Island's long-term projected EE investments presumed to be cost-effective?

A. Yes. The EE projections in the ISO-NE forecast are based on the most recent state-approved EE budgets and are assumed to continue in future years. The New England states, including Rhode Island, are committed to EE programs that are determined to be cost-effective.

Q. Will CREC unit 1 clearing FCA 10 affect the cost-effective EE programs planned for 2019/2020 and beyond?

A. No. ISO-NE's selection of CREC unit 1 may have resulted in rejecting new EE capacity resources, but those rejected resources would be less cost-effective than CREC; otherwise they

1 would have been selected in lieu of CREC unit 1 in FCA 10.[21] Cost-effective EE programs are
2 typically infra-marginal, i.e. do not set the capacity clearing price, and clear the FCAs as price-takers.
3 **Q. Are there any potential cost-effective EE&C resources that have not cleared an FCA**
4 **that can be procured instead of CREC and provide commensurate benefits?**
5 A. I am not aware of any incremental EE&C resources that could adequately replace CREC's
6 capacity. Moreover, under Least-Cost Procurement, annual electric and natural gas energy efficiency
7 programs are developed to achieve the full economic potential of cost-effective demand-side load
8 reductions. By definition, therefore, all cost-effective EE&C resources are already being procured in
9 Rhode Island.
10 **Q. Do you have an opinion whether cost-effective EE&C opportunities provide**
11 **appropriate alternatives to CREC?**
12 A. Yes. I believe that CREC will not hinder the development of cost-effective EE&C
13 opportunities, because National Grid is required to, and is in fact implementing, cost-effective
14 EE&C measures pursuant to Rhode Island regulations. EE&C opportunities will continue to be
15 implemented regardless of CREC and should not be viewed as alternatives to CREC.
16 **Q. Do you have an opinion whether renewable resource development will be affected by**
17 **CREC?**
18 A. Yes. Rhode Island currently has an active suite of renewable resource programs. A prime
19 example is the 30 MW Block Island Wind Farm, the nation's first commercial offshore wind project,
20 whose impacts will be felt throughout the entire New England region and not just in Rhode Island.
21 In addition, I am aware of the following specific renewable resource programs:
22 (i) Under the Rhode Island Distributed Generation Standard Contracts program (Chapter
23 39-26.2 of the Rhode Island General Laws), National Grid was directed to enter into

[21] ISO-NE rejected a set of smaller offers in FCA 10 but did not define their type or location.

fifteen year contracts for 40 MW of in-state wind, solar PV, and anaerobic digestion projects by year-end 2014.

(ii) The Rhode Island Renewable Energy Growth Program (Chapter 39-26.6) was designed to expand the Distributed Generation Standard Contracts program by an additional 160 MW by allowing customers to sell their generation output under long-term tariffs at fixed prices through year-end 2019.

(iii) The Rhode Island Renewable Energy Standard (Chapter 39-26) requires all electricity suppliers to provide a certain percentage of their retail sales from renewable energy resources and was recently extended and expanded from 14.5% by 2019 to 38.5% by 2035.

(iv) Rhode Island also supports renewable resource development through a Net Metering program (Chapter 39-26.4) for behind-the-meter systems up to 10 MW.

(v) Rhode Island exempts residential and manufacturing properties that install renewable energy systems from tangible property taxes on systems; a single statewide tangible tax rate for commercial renewable energy systems will be established by OER by November 30, 2015 and must be used by all municipalities by January 2, 2017. (Chapters 44-3-3 and 44-5-3).

(vi) Under the Affordable Clean Energy Security Act (Chapter 39-31), National Grid is authorized to participate in the issuance of regional competitive solicitations for clean energy resources and transmission, and is actively engaged in a multi-state procurement effort pursuant to that statute that was reviewed and approved by the PUC in Docket 4570.

I see no reason why any of the Rhode Island renewable resource programs listed above would be negatively affected by CREC.

Q. Have renewable resources participated and cleared in FCAs?

A. Yes. For example, ISO-NE's FCA 10 Results lists 51 new wind and solar projects that were awarded CSOs for the 2019/20 Capacity Commitment Period. Importantly, all new wind and solar resources qualified by ISO-NE for FCA 10 actually cleared according to the ISO-NE FERC Informational Filing posted on February 23, 2016. The total offered and cleared new wind and solar

capacity was about 73 MW, well below the 200 MW/year limit established by FERC for the Renewable Technology Resources exempt from the Minimum Offer Price Rule ("MOPR") that would otherwise trigger a review and potential mitigation of their capacity bids. This exemption allows any unused portion of the 200 MW not subject to the MOPR to be carried forward for up to three years for a possible total of 600 MW. Accordingly, as much as nearly 528 MW of new renewables can enter in FCA 11 without price offer review and mitigation, so they are virtually guaranteed to clear, with or without CREC.[22] This further supports my opinion that CREC will not interfere with Rhode Island's renewable resource programs.

CLF WITNESS FAGAN MADE SERIOUS ERRORS IN HIS CONCLUSIONS ON NEED

Mr. Fagan Does Not Fully Understand ISO-NE's Reliability Need and Capacity Procurement Process

Q. Did you review the pre-filed direct testimony of Robert M. Fagan of Synapse Energy Economics on behalf of CLF concerning the reliability need of CREC and what were your general conclusions?

A. Yes, I reviewed Mr. Fagan's testimony. He appears to have ignored the PUC's Hope Opinion and does not seem to fully understand ISO-NE's capacity procurement process. He over-estimated the role of distributed resources and renewables in the resource mix ISO-NE can rely upon to ensure system reliability, and under-estimated the role of conventional generating resources. Consistent with his views, he erroneously concluded that CREC is not needed for reliability.

[22] ISO-NE Presentation at NEPOOL Reliability Committee FCA 10 2019/2020 CCP Results Summary and Trends dated March 23, 2016.

1 **Q. What did Mr. Fagan claim was ISO-NE's reliability need?**

2 A. On page 4 of his testimony, Mr. Fagan claimed "The ISO NE forward capacity market
3 (FCM) auction is not indicative of reliability need, or even economic need, for the plant." On pages
4 11-12, he claimed ISO-NE's "Physical reliability needs are defined, in the near-term…by the
5 installed capacity requirement for the New England system as a whole, and by the local sourcing
6 requirement."

7 **Q. Do you agree with Mr. Fagan's understanding of ISO-NE's reliability need?**

8 A. No. Mr. Fagan views the ICR as a fixed requirement, consistent with the vertical demand
9 curve utilized in capacity procurements prior to FCA 9. Since then, ISO-NE and its stakeholders
10 have recognized the reliability and economic benefits of having more capacity at lower prices, i.e. the
11 sloped demand curve used in FCA 9 and FCA 10. The ICR (or NICR) is no longer a fixed
12 procurement target or a single need determinant; it is the FCA parameter corresponding to the
13 probabilistically-determined capacity required to meet the 1-in-10 LOLE reliability criterion.

14 **Q. Please explain the capacity need under the sloped demand curve.**

15 A. The FCAs are designed to clear the amount of capacity that the ISO-NE system needs to
16 ensure reliability while minimizing total capacity costs to be paid by consumers. As I explained
17 earlier, the sloped demand curve allows ISO-NE to procure capacity in excess of the NICR.
18 Capacity resources that clear are assigned CSOs by ISO-NE and are therefore needed. At the same
19 time, capacity resources offered at prices exceeding the clearing price do not clear, are not assigned
20 CSOs, and are not needed.

21 **Q. Does this concept of capacity need with a sloped demand curve contradict Mr.**
22 **Fagan's understanding?**

23 A. Yes. Mr. Fagan claimed on page 4 that ISO-NE's "…most recent forward capacity auction
24 cleared (or, established a financial obligation for) 1,416 MW more that the reliability requirement….

1 This result indicates a surplus capacity in excess of reliability requirements." Mr. Fagan's view of
2 need as a fixed quantity is consistent with the vertical demand curve that was eliminated prior to
3 FCA 9.[23] Moreover, he fails to recognize the reliability benefits or the cost-saving benefits of
4 procuring capacity in excess of the NICR with a sloped demand curve.

5 **Q. On pages 11-12, Mr. Fagan claims that the fact that CREC unit 1 cleared FCA 10 does**
6 **not necessarily mean that CREC is needed for reliability. Do you agree?**

7 A. No. FCA 10 cleared over 35,000 MW of new and existing capacity and assigned them
8 CSOs. Mr. Fagan claimed that the CSO is merely "...a financial obligation – but that it doesn't
9 mean the resource is physically needed for reliability." This ignores ISO-NE's longstanding capacity
10 procurement process to ensure resource adequacy. Moreover, in suggesting that CREC's CSO
11 "...can be sold or traded, to other parties..." Mr. Fagan ignores the fact that this would still leave
12 New England with a "surplus" of "unneeded" capacity.

13 As I stated earlier, a CSO is an ISO-NE-assigned obligation, whether CLF portrays it as
14 physical or financial. CREC unit 1 has a CSO and is therefore needed for system reliability. If and
15 when CREC unit 2 clears an FCA and is awarded a CSO, it too will be needed for system reliability.

16

17 **Mr. Fagan's Understanding of Need Is Inconsistent with the PUC's Current Position**

18

19 **Q. Did Mr. Fagan address need consistent with the PUC's position as expressed in the**
20 **<u>Hope Opinion</u>?**

21 A. No, Mr. Fagan did not address need as it is expressed in the <u>Hope Opinion</u> that reflects
22 Rhode Island's Utility Restructuring Act and New England's competitive wholesale power market
23 construct.

[23] FERC Order Accepting Tariff Revisions in Docket ER14-1639-000, May 30, 2014.

1 **Q. Is Mr. Fagan's belief that need is determined by the NICR and LSR consistent with**
2 **the PUC's old view of need and inconsistent with the PUC's today's view of need?**
3 A. Yes, Mr. Fagan appears to view need as it was expressed in the EFSA, prior to the
4 restructuring of the New England power system, i.e. as a fixed quantity. Since the Hope Opinion,
5 the PUC has changed its view of need and no longer considers it to be a fixed quantity. In the Hope
6 Opinion, the PUC stated "...we opined that the more recently enacted URA effectively repealed by
7 implication the much older 'need' assessment provisions of the EFSA (Id.)." New England's
8 competitive wholesale capacity market utilizes a sloped demand curve that allows ISO-NE to
9 procure more capacity than the NICR, which benefits Rhode Island customers. The parameters of
10 the sloped demand curve are carefully selected to ensure that the 1-in-10 LOLE reliability criterion is
11 met on a long term, average basis. Accordingly, the NICR and the LSR values are the long term
12 reliability targets that do not need to be precisely met in each individual FCA.
13
14 **Mr. Fagan's Claim that EE and BTM PV Could Displace the Output of CREC is Wrong**
15 **and Does Not Obviate the Need for CREC**
16
17 **Q. What are Mr. Fagan's projections of EE and BTM PV in New England and Rhode**
18 **Island? Do you agree with him?**
19 A. On page 13 of his Testimony, Mr. Fagan stated: "Energy efficiency and behind-the-meter
20 solar PV result in declining net peak load and declining annual net energy needs in New England
21 and Rhode Island... The existence of these resources alone – energy efficiency and behind-the-
22 meter solar PV – lowers forecast net demand."

1 I agree that EE and BTM PV lower the forecasted peak load, but only BTM PV lowers the
2 NICR which is used in the FCAs. EE is counted as a capacity resource in the FCM; ISO-NE does
3 not reduce the NICR by EE to avoid double-counting.

4 **Q. Do you agree with Mr. Fagan that "Energy efficiency and behind-the-meter solar PV**
5 **result in declining…annual net energy needs…" and eliminate the need for CREC?**

6 A. No. Some EE measures are designed to shift consumption from on-peak time periods onto
7 the off-peak time periods with no effect on the total energy consumption. More importantly, ISO-
8 NE already includes EE as Passive Demand Resources and BTM PV to reduce peak demand in its
9 FCAs.

10 **Q. Do you have any observations on Mr. Fagan's discussion of historical data and**
11 **forecasts for net peak load and annual energy starting on page 12?**

12 A. Yes. First, historical net peak load and annual energy data (Fagan Figures 1 and 2) are
13 interesting but not germane to the PUC's determination of need. That determination should be in
14 light of future conditions. Second, Mr. Fagan spends a lot of time discussing the 2016 CELT
15 forecast of annual gross and net energy for load (Figures 3 – 6) but capacity needs are driven by the
16 net peak load forecast (Figures 7 and 8). Forecasts of gross and net energy for load are not germane
17 to ISO-NE's need for capacity. The NICR forecast, which probabilistically incorporates the peak
18 load forecast, is germane.

19 **Q. On page 20, Mr. Fagan claimed "To the extent new grid-scale renewable resources**
20 **are built, the net energy needs from conventional natural gas-fired resources would decline**
21 **even more..." Do you agree?**

22 A. This statement is consistent with ISO-NE's economic dispatch of resources as I discuss in
23 more detail below. However, reliability need is driven by peak load requirements, not energy.

1 Moreover, even if more renewables are built, their inherent intermittency would increase ISO-NE's
2 need for flexible and responsive resources, like CREC.

3 **Q. Did Mr. Fagan address the ISO-NE operational reliability needs in his testimony?**

4 A. No, he did not. As I explained earlier, I believe CREC will be a valuable component of the
5 bulk power system that can be used to compensate for the intermittent energy output of BTM PV
6 and renewable resources in New England.

7 **Q. On pages 20 and 24, Mr. Fagan claimed that EE, BTM PV, and renewables can**
8 **"...displace the energy otherwise provided by the proposed Invenergy plant." Do you**
9 **agree?**

10 A. No, this concept is inconsistent with the way the ISO-NE works. These resources can
11 reduce ISO-NE's overall energy needs, but cannot displace energy from a particular plant. EE and
12 BTM PV reduce energy and peak load requirements, while renewable resources (assuming low
13 variable costs) will always be dispatched before fossil-fuel fired plants (ignoring locational
14 requirements, reserves, and other security constraints). None of these resources displace the energy
15 output of a particular plant. Additional low cost energy in the ISO-NE system would reduce the
16 output from virtually all of the more expensive energy sources, not just CREC. I note, however,
17 that EE, BTM PV, and renewables are not always available to displace energy demand, so
18 conventional, dispatchable resources will always be required to maintain system reliability. In any
19 event, if CREC is not dispatched as often as Invenergy claims, then it would be a problem for
20 Invenergy, not Rhode Island consumers.

21 **Q. On page 22, Mr. Fagan expressed his concerns about the "putative" need for CREC**
22 **if the system peak load declines. Do you share Mr. Fagan's concerns?**

23 A. No. First, in the near-term, new resources can clear in the FCAs if their capacity offers are
24 low enough, regardless of peak load and NICR growth. Second, many plants have retired in New

England and will continue to retire, increasing the opportunity for new resources to clear even with a declining NICR. Third, Mr. Fagan's claim that the peak load could decline in the future is inconsistent with ISO-NE's forecast.

In the long-term, after CREC becomes operational, the FCM process will determine whether CREC will be needed or not. If CREC clears in future FCAs and is awarded CSOs, it will be needed. If CREC fails to get a CSO in the future, it will not be needed and Invenergy would be at risk, not Rhode Island customers.

Q. On pages 24-27 Mr. Fagan claimed that "…the solar PV forecast contained in the current <u>2016 CELT</u> forecast is conservative…" which will put "…downward pressure on the need for new capacity resources." Do you agree?

A. I am reluctant to second-guess ISO-NE's forecast of BTM PV. This forecast was vetted through a regional stakeholder process in which all stakeholders could participate. ISO-NE's monthly BTM PV forecast was included on pages 27-28 of the <u>2019/20 ICR Values Report</u> and was accepted by FERC. I do not believe Mr. Fagan has greater insight in future BTM PV development on New England than ISO-NE.

Mr. Fagan's Opinions on Long-Term Resource Forecasts Are Not Relevant to the DPUC Determination of Need

Q. On page 28, Mr. Fagan claimed: "ISO-NE regional planning forecasts of capacity requirements do not indicate any specific need for the Invenergy plant." Do you agree?

A. Mr. Fagan presented a straw man argument, since these forecasts are not resource-specific. ISO-NE is not a stakeholder and is not biased for or against any technology or resource category. ISO-NE administers the FCA where all capacity resources compete on a level field.

1 **Q. In Figure 12, Mr. Fagan provided ISO-NE's projected resource surplus/shortage**
2 **data in the Capacity Commitment Periods from 2020/2021 to 2024/2025 and claimed there is**
3 **a "...resource surplus beginning 2020, and into the middle of the next decade." Do you**
4 **agree?**
5 A. No, Mr. Fagan mischaracterized the ISO-NE data. First, I note Mr. Fagan's data indicates
6 ISO-NE's peak load is growing from 30,182 MW in 2020/2021 to 31,455 MW in 2024/2025.
7 Second, the resource surplus is relative to the NICR, and we've already explained that ISO-NE can
8 and does procure capacity in excess of the NICR for the benefit of New England consumers. Only
9 by ignoring ISO-NE's adoption of a sloped demand curve could Mr. Fagan claim the resource
10 surplus indicates no need for CREC.
11 Third, footnote (d) of Mr. Fagan's Figure 12, which is ISO-NE's System-Wide Resource
12 Needs, states that "additional resources would be required if additional resources retired or less
13 capacity imports obtain CSOs." As I've pointed out, there have been some significant retirements
14 of sizeable power generating facilities in recent years, and more are possible. According to page 11
15 of ISO-NE's 2016 Regional Electricity Outlook, "More than 4,200 MW of the region's nongas
16 generating capacity has retired or plans to retire soon." These plants include Salem Harbor,
17 Vermont Yankee, Pilgrim, Brayton Point, Mt. Tom, and Norwalk. In addition, ISO-NE considers
18 an additional 6,000 MW to be at risk of retiring, including Yarmouth, Merrimack, Newington,
19 Schiller, Mystic 7, West Springfield, Canal, Middletown, Montville, New Haven, and Bridgeport 3.
20 Mr. Fagan should not assume that the region's current resource surplus will persist "...into the
21 middle of the next decade."
22 **Q. In his final claim, Mr. Fagan claimed that Invenergy did not "...examine long-term**
23 **resource issues...to any level of detail." Do you agree?**

1 A. This is another straw man argument. First, Invenergy was not required or directed to
2 examine long-term resource issues. Second, CREC unit 1 was awarded a CSO in FCA 10; ISO-NE
3 is now relying on CREC unit 1 to commence operations on June 1, 2019. Third, ISO-NE's capacity
4 procurement process, designed to assure system reliability, is conducted for one year at a time, three
5 years in advance of the Capacity Commitment Period. ISO-NE does not make long-term resource
6 commitments.
7
8 **CLF WITNESS STIX MADE SERIOUS ERRORS ON CREC CAPACITY BENEFITS**
9 **AND OFFERED NO SUPPORT FOR HIS CONCLUSION ON ENERGY BENEFITS**
10
11 **Mr. Stix Does Not Understand ISO-NE's Capacity Procurement Process**
12
13 **Q. Did you review the pre-filed direct testimony of Christopher T. Stix of CLF and what**
14 **were your general conclusions?**
15 A. Yes, I reviewed Mr. Stix's testimony. He appears to have some fundamental
16 misunderstandings of ISO-NE's capacity procurement process, some of them serious, which leads
17 me to question his calculations of consumer savings. While he and I agree that Invenergy's
18 estimated savings for Rhode Island consumers are likely exaggerated, I disagree with many of Mr.
19 Stix's analyses and conclusions.
20 **Q. What is your first observation about Mr. Stix's testimony?**
21 A. Mr. Stix focused a large part of his testimony on Invenergy's initial $280 million savings
22 estimate instead of Invenergy's updated estimate of $210 million. He eventually acknowledged that
23 Invenergy provided an updated estimate but criticized Invenergy for not correcting "...its gross
24 error in a timely way." As we know, Invenergy witness Hardy presented the updated savings

estimate in his testimony of April 22, 2016. I believe this timing issue is minor and does not warrant further discussion.

Q. What is your next concern about Mr. Stix's testimony?

A. Mr. Stix appears to have a fundamental misunderstanding of ISO-NE's capacity procurement process. On page 8 where he discussed FCA 10, Mr. Stix claimed that the amount of "...capacity it needs and wants to procure in the upcoming FCA...is called the Installed Capacity Requirement (ICR). The ICR is the largest amount of electricity that ISO believes it could possibly require for system reliability at the time of year when electricity load is greatest."

First, as a point of clarification, the FCM capacity requirement is the NICR, not the ICR as is labeled by Mr. Stix. The NICR takes into account the reliability contribution of Hydro Quebec. The ICR for FCA 10 was 35,126 MW; the NICR was 34,151 MW, or 975 MW lower. This is a minor issue of terminology.

Mr. Stix's second mistake is more serious when he claims "The ICR is the largest amount of electricity that the ISO believes it could possibly require for system reliability..." In fact, the reverse is true. Section III.12.1 of the ISO-NE Tariff defines the ICR as follows:

> The ISO shall determine the Installed Capacity Requirement such that the probability of disconnecting non-interruptible customers due to resource deficiency, on average, will be no more than once in ten years. Compliance with this resource adequacy planning criterion shall be evaluated probabilistically, such that the Loss of Load Expectation ("LOLE")...shall be no more than 0.1 day each year.

ISO-NE establishes the ICR as the *minimum* amount of capacity to meet the 1-in-10 reliability standard in light of total forecasted load requirements for the New England Control Area. According to page 15 of the 2019/20 ICR Values Report, ISO-NE uses the GE Multi-Area Reliability Simulation Model ("MARS"), a sophisticated "...computer program that uses a sequential

1 Monte Carlo simulation to probabilistically compute the resource adequacy of a bulk electric power
2 system by simulating the random behavior of both load and resources."
3 Third, he compounded his misunderstanding by stating on page 9 "...the ISO had
4 determined that during CCP-10...electricity load in New England would go above 34,151 MW, on
5 average less than once every 10 years..." This is a gross misinterpretation of the 1-in-10 LOLE
6 reliability criterion. Mr. Stix wrongfully equates the ICR to the peak load not being exceeded more
7 than once in 10 years. The 1-in-10 LOLE reliability criterion is the probability of disconnecting
8 non-interruptible load due to a resource deficiency accounting for all available measures, including
9 activating reserves, voltage reduction, voluntary load curtailment, full utilization of the tie benefits,
10 and requesting emergency support from the neighboring control areas. The 1-in-10 LOLE reliability
11 criterion has virtually nothing to do with the probability that load will be above the ICR. In fact,
12 ISO-NE assumes a 50/50 load forecast when it sets the ICR, explicitly recognizing that the peak
13 load could be higher than is assumed in the ICR calculations 50% of the time.[24]
14 **Q. Does Mr. Stix's misunderstanding of ISO-NE's capacity procurement process**
15 **undermine his analysis?**
16 A. Yes. Mr. Stix does not appear to understand that the ICR (or NICR) is the minimum
17 amount of capacity required for reliability, is unaware of ISO-NE's probabilistic modeling process,
18 and confuses the 1-in-10 LOLE planning criterion with the chance that load will be above the ICR.
19 I believe these misunderstandings are fundamental and undermine his analysis.
20
21 **Mr. Stix's Calculations of the Expected Capacity Benefits Contain Errors**
22

[24] Load uncertainty is just one probabilistic variable in ISO-NE's reliability planning process. On pages 16-17 of the 2019/20 ICR Values Report, ISO-NE lists many probabilistic and deterministic variables included in its reliability model, including load, forced and scheduled outage rates, deratings, seasonal capability adjustments, maintenance requirements, operating procedures, and interconnections with adjacent systems.

Q. What is your next concern regarding Mr. Stix's testimony?

A. On page 14, Mr. Stix claimed that ISO-NE "...would still have obtained more capacity in the zone that included Rhode Island [SENE] than the ISO needed..." even without CREC. However, he failed to consider the reliability benefits or the consumer savings under the FCA sloped demand curve he himself described thoroughly on pages 10-11 of his testimony. In designing the sloped demand curve, ISO-NE explicitly recognized the higher reliability value of procuring more capacity than the NICR, as I have already addressed in this testimony.

Moreover, the consumer savings from procuring more capacity than the NICR should not be ignored. Under the FCA 10 sloped demand curve, more capacity means a lower clearing price and a lower total capacity cost for consumers. This effect can be demonstrated by the following simplified calculations of the total FCA 10 capacity costs paid by New England consumers under two scenarios: (i) actual FCA 10 results with 35,567 MW cleared at $7.03/kW-month, and (ii) assuming FCA 10 cleared at the NICR of 34,151 MW at the associated price of $12.62/kW-month.[25] As shown in Table 3, the actual total FCA 10 capacity cost for New England consumers will be $3 billion, while the total cost would have been more than $5 billion if FCA 10 cleared at the NICR. By procuring capacity in excess of the NICR in FCA 10, ISO-NE saved New England customers more than $2 billion.

Table 3. Sample FCA 10 Results

	Capacity (MW)	Clearing Price ($/kW-mo)	Total Cost (billions)
Cleared Capacity	35,567	$ 7.03	$3.00
NICR Capacity	34,151	$12.62	$5.17

Q. Does that mean if ISO-NE procured exactly the NICR amount in FCA 10, costs for Rhode Island consumers would be higher?

[25] See Robert Ethier's testimony, Attachment C in the ISO-NE's FCA 10 Results, FERC Docket ER16-1041-000.

1 A. Yes. Rhode Island consumers would have to pay more if FCA 10 cleared at the NICR,
2 compared to the actual result.

3 **Q. Do you agree with Mr. Stix's claim that ISO-NE "over-procured" capacity in FCA 10**
4 **for SENE?**

5 A. No. Having a sloped demand curve means that ISO-NE may procure capacity above the
6 NICR from time to time. This is by design, and it is inaccurate to characterize this as a flaw in ISO-
7 NE's capacity procurement process.

8 **Q. What was Mr. Stix's estimate of the capacity cost savings for Rhode Island**
9 **consumers due to CREC, and how does it compare to Invenergy's estimate?**

10 A. On page 18 of his testimony, Mr. Stix estimated that CREC would save Rhode Island
11 consumers between "...close to zero and just $36 million." I note that his upper end, $36 million, is
12 very close to Invenergy's estimate of just under [Confidential] [redacted] million for the 2019/20 Capacity
13 Commitment Period based on the Clear River Cost to Load – Post FCA 10 spreadsheet that
14 Invenergy submitted in response to DPUC DR 2-1.

15 **Q. Do you agree that the actual savings for Rhode Island consumers could be less than**
16 **[confidential] [redacted] million (according to Invenergy) or less than $36 million (according to**
17 **Stix) for the 2019/20 Delivery Year?**

18 A. Yes, as I explained earlier in my testimony, the actual FCA 10 savings depend on the slope
19 of the supply curve in the region around the demand curve, among other factors. Without knowing
20 that slope, I cannot know the point where the supply and demand curves intersect without CREC,
21 and thus the capacity cost savings for Rhode Island consumers.

22 **Q. After presenting his estimate of capacity cost savings, what did Mr. Stix address next**
23 **in his testimony?**

1 Mr. Stix pointed out two of Invenergy's "incorrect" assumptions on pages 22-24. First,
2 Invenergy assumed CREC's entire 997 MW capacity would clear in FCA 10. The claim that this
3 assumption was incorrect was made with the benefit of hindsight; I consider this to be a minor issue.
4 Second, Mr. Stix claimed there would be "...at least 735 MW of capacity other than
5 Invenergy bidding into the auction..." based on the fact that round 3 of FCA 10 was completed
6 with 1,732 MW of excess capacity at an $8.50/kW-month price.[26] The amount of capacity that
7 would stay in FCA 10 with CREC could not have been known in advance, so this is a minor issue as
8 well. However, we agree with Mr. Stix that Invenergy's assumption of no other resources offering in
9 the same price range was unreasonable.

10 **Q. Did Mr. Stix next present his estimated results for FCA 11?**

11 A. Yes. Mr. Stix presented his assumptions and estimated results for FCA 11. First, Mr. Stix
12 assumed that the modified demand curve submitted by ISO-NE to FERC on April 15, 2016 will be
13 in effect for FCA 11.[27] Next, he estimated the NICR at 33,851 MW, 300 MW lower than in FCA
14 10. Third, he assumed all capacity that cleared FCA 10 would enter FCA 11 as existing resources,
15 new renewable resources of 600 MW, and retirements of 363 MW for a total of 35,804 MW clearing
16 FCA 11.

17 **Q. Do you believe Mr. Stix's assumptions related to FCA 11 are reasonable?**

18 A. No, Mr. Stix made many assumptions that are not much more than guesswork. First, Mr.
19 Stix's NICR estimate for FCA 11 is poorly supported and is based on the 2016 CELT peak forecast
20 for summer 2020 being 611 MW lower than the 2015 CELT. Mr. Stix converted the 611 MW peak
21 load reduction into a 300 MW NICR reduction for FCA 11. However, his simplistic approach of

[26] 1,732 MW of excess capacity less 997 MW of CREC still leaves 735 MW remaining after round 3 of FCA 10.

[27] FERC approved the ISO-NE modified demand curve proposal in Docket ER16-1434-000 on June 28, 2016.

setting the NICR ignores the complex aspects of ISO-NE's reliability methodology as I described earlier in my testimony.[28]

Second, Mr. Stix assumed that a new 600 MW Clear Energy Connect project would clear in FCA 11 in addition to the existing capacity that cleared in FCA 10. Mr. Six did not provide any support for this new project and even admitted it is not in the ISO-NE Interconnection Queue. There are other projects in the ISO-NE Queue that are further along in their development; I do not know why he claimed this assumption as "conservative."

Third, Mr. Stix estimated retirements based on 27 MW of Non-Price Retirements and Permanent De-List bids for FCA 11 plus the average amount of accepted Static De-List capacity, 336 MW, in the past five FCAs. These accepted Static De-List Bids varied significantly in those FCAs and Mr. Stix ignored the fact that the individual Static De-List Bids became effective at different prices; averaging them is overly simplistic.

Q. How did Mr. Stix derive the FCA 11 clearing price of $5.50/kW-month based on these assumptions?

A. According to pages 38-41 of his testimony, Mr. Stix first combined his estimates for existing (including CREC unit 1), new, and retired capacity to estimate that 35,804 MW would clear in FCA 11 at $5.50/kW-month. He next removed 485 MW of CREC unit 1 and arrived at an FCA 11 clearing quantity of 35,319 MW and a clearing price of $6.64/kW-month (without both CREC units). Lastly, Mr. Stix added 970 MW for both CREC units to the supply curve. Mr. Stix determined that FCA 11 "...would clear with all of Invenergy's now-projected contribution of 970 MW...at $5.50/kW-month..." Even though he did not specify the capacity clearing quantity with

[28] The 2019/20 ICR Values Report goes on to explain "...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

both CREC units, he earlier determined that the $5.50/kW-month price corresponds to 35,804 MW clearing FCA 11.[29]

Q. Has Mr. Stix changed his opinion regarding the cleared FCA 11 capacity since he submitted his testimony?

A. It appears so. In response to Invenergy's DR1-10, Mr. Stix explained that the CFA 11 demand "...curve reaches the Dynamic De-List price of $5.50 at 35,580 MW. A this point, I estimate the existing capacity will delist to keep the price at $5.50/kW-month." Even though Mr. Stix still believes the FCA 11 clearing price with CREC will be $5.50/kW-month, somehow the clearing quantity dropped from 35,804 MW in his testimony to 35,580 MW in his response.

Q. Is the $6.64/kW-month price determined by Mr. Stix without CREC consistent with his revised estimate that 35,580 MW will clear in FCA 11 with both CREC units?

A. No. If the total CREC capacity of 970 MW is deducted from 35,580 MW, the total amount of capacity that would clear FCA 11 without CREC would be 34,610 MW. In response to Invenergy's DR1-10 Mr. Stix explained that "the [demand] curve is horizontal at $7.03 from 34,510 MW to the point 35,232 MW." The clearing quantity of 34,610 MW without CREC is in this range and therefore the corresponding FCA 11 clearing price would be $7.03/kW-month, not $6.64/kW-month.

Q. Isn't Mr. Stix concerned that ISO-NE would be "over-procuring" capacity in FCA 11?

A. No, the "over-procurement" of 1,729 MW above the NICR did not seem to bother Mr. Stix. We note that in Mr. Stix's analysis this amount is not affected by CREC unit 2.[30]

Q. What were Mr. Stix conclusions about the CREC capacity benefits in FCA 11?

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[29] This implies that dynamic de-list bids have offset part of the CREC capacity (35,319 MW w/o CREC + 970 MW CREC = 36,289 MW, which exceeds 35,804 MW).

[30] The 1,729-MW "excess" of capacity is calculated by deducting 33,851 MW of NICR from 35,580 MW.

A. Mr. Stix concluded that the maximum benefit from FCA 11 attributable to CREC would be $28 million, based on the $5.50/kW-month clearing price with CREC and $6.64/kW-month without CREC.

Q. Did Mr. Stix update his FCA 11 savings estimate in his response to Invenergy DR 1-10?

A. No. Mr. Stix neglected to update his maximum FCA 11 savings estimate of $28 million in his testimony. The clearing quantity of 35,095 MW (or less) without CERC that I estimated above based on Mr. Stix's response to Invenergy DR 1-10 implies a $7.03/kW-month price without CREC. This, in turn, results in a larger wholesale capacity price differential between the $5.50/kW-month clearing price with CREC and the higher $7.03/kW-month without CREC. This should raise Mr. Stix's maximum FCA 11 savings estimate.

Q. Do you agree with Mr. Stix's estimated wholesale capacity price benefits?

A. No. As I described above, there is too much uncertainty with the assumptions used by Mr. Stix and too many questions about his calculations for me to agree to his estimated FCA 11 results. His claims concerning the FCA wholesale capacity clearing prices with CREC and without CREC are not well supported, particularly his assumptions of the quantity of Dynamic De-List Bids that must be accepted for FCA 11 to conclude. Mr. Stix's claim that FCA 11 would clear at $5.50/kW-month with or without CREC unit 2 can only be viable with inconsistent quantities of Dynamic De-List Bids.

Q. Do you agree with Mr. Stix on page 45 that "...it is impossible, with the facts that are publicly known, to derive a precise figure" for the capacity cost savings due to CREC?

A. Yes, it is not possible to derive a precise figure to estimate a capacity cost savings. However, there is so much uncertainty and guesswork in Mr. Stix's calculations that I would characterize his

1 estimated results as unreliable. Moreover, Mr. Stix's contention that the lower end of the customer
2 savings for FCAs 10 and 11 could be "close to zero" is undoubtedly too conservative.
3
4 **Mr. Stix's Conclusion on the Expected Energy Benefits is Subjective**
5
6 **Q. Did Mr. Stix also criticize Invenergy's estimated energy savings?**
7 A. Yes, he compared the estimated wholesale energy price reductions for four proposed power
8 projects in New England and argued that if all these claimed reductions came to pass, "they will
9 depress energy clearing prices so far that there just won't be any meaningful margin left in the
10 business." Moreover, he claimed that the resulting lower energy margins would drive up capacity
11 prices. However, he did not claim that Invenergy's estimated savings of "nearly $10 million
12 annually" for Rhode Island consumers was incorrect or unreasonable.
13 **Q. Do the four projects Mr. Stix included shed any light on the reasonableness of**
14 **Invenergy's estimated energy price reduction?**
15 A. Yes. First, Invenergy's estimate of $2.36/MWh is in the middle of the range presented by
16 Mr. Stix. Second, if we consider just the first three projects that are combined cycles that should
17 have similar capacity factors, the estimated energy price reduction for CREC is below the other two
18 when their size is considered.[31] Thus the data presented Mr. Stix seems to indicate that Invenergy's
19 estimated energy savings is not unreasonable.
20 **Q. Do you agree with Mr. Stix that if these and other proposed plants are built they will**
21 **lower energy prices and cause capacity prices to rise?**

[31] One project, Medway, is a 200 MW gas turbine peaker that will likely have a much lower capacity factor than the combined cycle plants. According to the project website, Medway will "...only run when demand for electricity is unusually high – during "peak" demand times such as very cold winter or hot summer days."

1 A. He may be correct that building many new, efficient power plants may cause wholesale
2 capacity prices to rise, but this is irrelevant to this matter. Mr. Stix explained "...this is exactly how
3 the ISO-run markets were designed to operate." However, Mr. Stix neither quantitatively evaluated
4 Invenergy's estimated energy savings nor provided any factual support for his subjective claim that
5 falling energy margins will cause capacity prices to rise.
6 Perhaps more fundamentally, I am unsure if such a relationship between wholesale capacity
7 and energy prices is relevant to Invenergy's Application for CREC. Regardless of the veracity of Mr.
8 Stix's claim, I still believe that CREC will provide net savings for Rhode Island consumers.
9 **Q. Does this conclude your testimony?**
10 A. Yes.

SETH G. PARKER

SUMMARY

A senior manager with an international background in competitive markets, the development / evaluation / financing of generation and transmission projects, and mergers / divestitures / acquisitions. Key experience includes market design, transaction support, risk management, power contracts, cogeneration / microgrids, economics of conventional and renewable power resources, inter-regional transmission projects, and asset valuation.

PROFESSIONAL EXPERIENCE

1998 - **Levitan & Associates, Inc.**
Principal & Vice President
Managing Consultant

1988-1998 **Stone & Webster Management Consultants (US and UK)**
Vice President
Assistant Vice President
Executive Consultant
Senior Consultant

1984-1988 **J. Makowski Associates, Inc.**
Financial Manager - Ocean State Power

1981-1983 **ThermoElectron Energy Systems**
Senior Financial Analyst

1978-1981 **Pacific Gas and Electric Co.**
Project Financing Analyst

CONSULTING ASSIGNMENTS

RENEWABLE ENERGY

Administering an offshore (Delmarva Peninsula) wind application, evaluation, and selection process for the Maryland Public Service Commission; managing three subcontractors for cost, technical, permitting, regulatory reviews and project selection.

Forecasted power market, emission, and rate impacts of New England Clean Power Link, a proposed 1,000 MW u/w and u/g HVDC cable to import renewable hydroelectric and wind energy from Quebec for TDI-NE's Certificate of Public Good application to the Vermont Public Service Board.

Assisted NRG with economic analysis, financing structure, debt and equity sources, finance rates, PPA terms, and credit issues for the proposed Great Lakes Offshore Wind project in Lake Erie.

Prepared comprehensive offshore wind report defining application requirements, recommending price parameters, establishing threshold qualifications, and specifying evaluation criteria and procedures adopted in Regulations to implement the Offshore Wind Energy Act of 2013; testified before the Maryland Public Service Commission.

Conducted economic evaluation of the Deepwater Block Island offshore wind project for the Rhode Island Economic Development Corporation, including PPA pricing, risk allocation, price suppression, regional economic impacts, and other issues; submitted written testimony and testified before the Rhode Island Public Utility Commission.

Advised New York University on nearby wind project development and contracts; evaluated micro-grid proposal for NYU's Brooklyn campus post-Superstorm Sandy.

Assessed economics of hydroelectric purchase and underwater cable cost-sharing per the Nova Scotia Power Maritime Link Compliance Filing, including proposed Energy Access Agreement, for the Consumer Advocate and Small Business Advocate; submitted written testimony and testified before the Utility and Review Board.

Established economic value and financing plan for existing 43 MW Massachusetts hydroelectric power plant in support of acquisition and financing by a municipal utility.

Advised The Stanley Works on business strategy / financing of 8 MW hydro plant.

MARKET & POLICY ANALYSIS

Represented Long Island Power Authority (LIPA) at PJM Members Committee, Markets and Reliability Committee, and Market Reliability Committee meetings and at NYISO Credit Policy Working Group meetings.

Assisted the Vermont DPS on power market, reliability, environmental, and socio-economic issues regarding extending Vermont Yankee's Certificate of Public Good; testified before the Vermont Public Service Board.

Evaluated alternative resource options and the market price and socio-economic impacts associated with the potential retirement of Vermont Yankee on behalf of the Vermont DPS; submitted written testimony and testified before the Vermont Public Service Board and in US District Court.

Assessed the economic costs and benefits of the proposed Cape Cod HVAC transmission line versus generation and demand-side alternatives; utilized in filings to the Massachusetts Energy Facilities Siting Board on behalf of project sponsor NStar.

Advised the Virginia State Corporation Commission Staff on commercial and technical issues for the HVAC Potomac-Appalachian Transmission Highway (PATH) project, including need, cost, timing, market impacts, and alternative transmission solutions.

Advised three New York City (NYC) generators on the NYISO installed capacity demand curve reset process for 2011/12 – 2013/14 focusing on peaker proxy technology / cost, transmission deliverability, site requirements, and net energy and ancillary service revenue calculation.

Provided written testimony on resource options and economics on behalf of Shell Energy NA regarding Dominion Virginia Power's (DVP's) 2009 Integrated Resource Plan; testified before the Virginia State Corporation Commission.

Prepared expert report and testimony on the DVP 2007 Solicitation for 2011 Unit Capacity for Shell Energy NA that addressed capacity needs, bidder qualifications, best competitive procurement practices, and bid evaluation methodology.

Prepared major deregulation study for the Maryland Public Service Commission that evaluated new generation, transmission, and demand-side options; evaluated divestiture's financial impact on generation fleet and to parent company; updated study for rate-base utility or power authority generation ownership.

Advised New York Power Authority (NYPA) on inter-market transactions, including power economics, interconnection requirements, grid upgrades, reliability impacts, permit issues, and regulatory considerations.

Advised generator group on PJM's proposed Reliability Pricing Model (RPM) capacity valuation mechanism, including gas turbine capital & operating costs, net revenues, financing charges, etc.; represented group's interests at FERC.

Assessed market prices and congestion costs relative to competing generation and transmission project bids for LIPA; prepared ICAP forecasts across northeast markets and commercial analysis of HVDC cable proposals.

Evaluated market potential of PJM cable exports into NYC for potential purchaser of Linden simple / combined cycle project, including cable expansion issues.

Managed the update of NYISO's capacity market demand curve parameters for 2005/06 - 2007/08 based on levelized costs of gas turbine peaker capacity (CONE), including net energy revenues from multi-regional simulation model with stochastic treatment of hourly loads; evaluated demand curve slope and zero-crossing point; achieved consensus with stakeholder group; submitted report to FERC for approval.

Advised counsel for Mirant Equity Committee regarding NYISO, ISO-NE, and PJM capacity markets and the demand curve mechanisms used to forecast ICAP prices.

Established feasibility of inter-pool wheeling into load pocket to reduce congestion costs; quantified maximum benefit and reliability / portfolio effects for LIPA.

Evaluated alternatives to the Indian Point Nuclear Power Station for Westchester County and its Public Utility Service Agency, including power and local economic implications of shut-down, repowering, replacement with transmission / conventional / renewable resources, continued operation, and license extension.

Estimated market value of incremental energy and capacity from the Bonanza coal plant owned by the Deseret Generation and Transmission Cooperative in Utah; submitted expert report and testified in US District Court.

Prepared analysis of US power markets and merchant plant business structures for overseas investor; recommended target areas and distressed asset screening model.

Advised stakeholder group on technical, environmental, operational, and regulatory issues of power and gas infrastructure projects across Long Island Sound and in southwest Connecticut for the Institute for Sustainable Energy; facilitated revised guidelines for Connecticut Siting Council.

Prepared long-term market price forecasts by sub-regions in New England, New York, and PJM to capture congestion effects for PECO Energy's acquisition of Sithe assets.

Power market analysis of Salem Harbor conversion to gas for ISO-NE White Paper.

Assessed market potential for independent power producers throughout the US; identified competitive capabilities of utility and non-utility developers and of engineering firms.

ISO-NE cogeneration marketing and permitting assistance for Unitil gas utility.

Assessed state-by-state future demands for cogeneration systems based upon industrial activities, fuel costs, utility purchase and sales rates, and regulatory climates.

PROJECT DEVELOPMENT

Conducting power market analysis of a proposed 1,500 MW gas-fired combined cycle project in support of siting approvals in New Jersey for Genesis Power LLC, including impacts on wholesale energy prices, capacity prices, and air emissions in PJM.

Advised a confidential client on commercial / operational issues for an inter-market HVDC cable system, including scheduling, performance risks, O&M issues, and converter technology.

Advised Maine Department of Transportation on proposed LNG terminal project, including feasibility, site, safety, comparative economics, and pipeline routing.

Responsible for commercial and financial analysis of 13.4 MW NYU cogeneration / microgrid project, including economic feasibility, contract terms, and utility backup power. Project "kept the lights on" during Superstorm Sandy, saves NYU $5-$8 million/year, and reduces NO_x, SO_2, and CO emissions in NYC.

Formulated economic / regulatory basis and completed pre-financing development work (permits, construction, and financing) for the 225 MW Ocean State Power Phase I combined cycle plant in Rhode Island, the nation's first IPP.

PROJECT & DUE DILIGENCE EVALUATIONS

Advising the Rhode Island Department of Division of Public Utilities and Carriers (DPUC) on the 1,000 MW dual-fueled combined cycle Clear River Energy Center Application to the Energy Facility Siting Board on need and cost issues.

Advised Simpson Senior Services on termination payment and other contract terms with a third party cogeneration developer / operator for their assisted living facility.

Evaluated the status of proposed nuclear plant upgrades for the New Jersey Board of Public Utilities in support of its Long-Term Capacity Agreement Pilot Program (LCAPP), including Nuclear Regulatory Commission decisions on uprate applications.

Forecasted expected operating regime and changes in market power prices and regional air emissions for Bayonne 512 MW gas turbine peaker plant with HVAC underwater cable lead into NYC; report was used for Bayonne's Article VII Certificate application.

Prepared revenue and operating expense projections of PJM coal and combined cycle plants being sold by AES, including capacity revenues under alternative scenarios.

Advised the New York State Housing Finance Agency as lender to a cogeneration project, including project review, contract negotiation, and financing terms.

Managed due diligence review, construction monitoring, and acceptance testing of cogeneration, combined cycle, fluidized bed, and industrial projects for commercial lenders, investment banks, and government, bilateral & multilateral agencies:

- Brooklyn Navy Yard, 220 MW cogeneration plant, New York
- Derwent Cogeneration Project, 210 MW cogeneration plant, England
- East Java Power, 500 MW combined cycle plant, Indonesia
- EES Coke Battery, 900,000 ton per year coke facility, Michigan
- Guna Power Project, 347 MW naphtha / gas combined cycle plant, India
- Hadley Falls, 43 MW hydroelectric plant, Massachusetts
- Hub Power, 1,200 MW, $1.8 billion, World Bank-supported plant, Pakistan
- Indiana Harbor Coke Battery, 1.3 million ton per year facility, Indiana
- Kot Addu, 1,600 MW oil / gas combined cycle plant, Pakistan
- Midland Cogen Venture, 1,370 MW $2.3 billion cogen plant, Michigan
- Niagara Falls Resource Recovery, 800,000 ton per year plant, New York
- Panther Creek, 80 MW fluidized bed power plant, Pennsylvania
- Warrior Run, 180 MW fluidized bed power plant, Maryland
- York Research, financing of four plants, Texas, New York, and Trinidad

Evaluated operating characteristics and economics of cogeneration expansion plans for the Massachusetts Institute of Technology, and recommended phased-in scheduling.

Managed due diligence reviews of US coal and gas-fired power plants in support of Manweb (UK) equity investments; helped negotiate transaction modifications.

Recommended cogen plant design and financing plan for Turkish Industrial Zone.

Evaluated the feasibility of converting the Bataan nuclear power station in The Philippines to a gas-fired combined cycle plant for Shell Oil Company.

AUCTIONS & PROCUREMENTS

Independent monitor on behalf of the California Public Utilities Commission for Southern California Edison's Fixed Price Request for Offers from non-gas fired Qualifying Facilities; authored Independent Evaluator Report for the Commission.

LCAPP Agent for the New Jersey Board of Public Utilities to develop 2,000 MW of new capacity; responsible for evaluating bidder financial strength / development expertise, contract drafting, and security (letter of credit and escrow) provisions.

Retained by the Illinois Power Authority as Procurement Administrator for the 2008, 2009, 2010, and 2011 competitive procurements of energy, capacity, and RECs, the 2010 procurement of long-term renewable resources, and the 2012 Rate Stability energy and RECs procurement for the Ameren Illinois Utilities; responsible for benchmark pricing, finance, credit, security, performance, and related contract issues.

Advised the Connecticut PURA on economic costs / benefits, credit / collateral terms, and other contract conditions for long-term PPAs.

Conducted power and fuel price forecasts and financial analysis for a confidential equity investor in the auction of the 2,480 MW Ravenswood Facility in NYC.

Assisted Allegheny Electric Cooperative to identify power purchase and equity investment opportunities in PJM; evaluated economics and risk parameters of PPA, tolling, market purchases, and ownership options; reviewed ISDA and EEI agreements.

Part of the Procurement Monitor team for PURA to oversee Connecticut Light & Power and United Illuminating 2006-2012 supply procurements; responsible for credit issues and financial barrier options to protect against unanticipated price movements.

Advised LIPA on commercial and financial issues associated with multiple solicitations for on-island and off-island capacity and energy; refined contract terms on risk and credit.

Evaluated 3rd party contracts and on-site generation alternatives for Visy Paper, NYC.

Evaluated design-build proposals for Central Heating Plant (CHP) at Rochester Institute of Technology, including engineering / construction qualifications, O&M strategy, financial structure, utility interconnection, and lifecycle cost / ROI results.

Evaluated strategic electric and gas procurement strategy options for the Buffalo Fiscal Stability Authority; made procurement recommendations to BFSA and City officials.

Evaluated bidders for Indianapolis Power & Light's 1992 competitive power solicitation.

MERGERS, ACQUISITIONS, & DIVESTITURES

Evaluated proposed spin-off of Entergy transmission assets and merger with ITC Holdings for the Mississippi Public Utilities Staff including financial effects, business risk, transmission planning / operations, MISO regulation, and rate impacts; submitted written testimony.

Advised the Vermont Department of Public Service (DPS) on financial, operational, decommissioning funding, and ratepayer risk issues of Entergy's application to restructure the ownership of its merchant nuclear plants, including Vermont Yankee; submitted written testimony and testified before the Vermont Public Service Board.

Advised the Connecticut Pubic Utilities Regulatory Authority (PURA, previously the DPUC) on financial policy issues of proposed Northeast Utilities / NStar merger.

Prepared comprehensive descriptions of Southern California Edison thermal generation (12 plants, 10,000 MW) and Commonwealth Edison coal stations (6 plants, 6,000 MW) for Divestiture Offering Memorandum.

Technical and economic advisor to Maine Public Service, Fitchburg Gas and Electric, and Unitil Corp for hydro, thermal, and power purchase agreement divestiture.

Commercial and contract advice to Empressa Electrica de Guatemala, S.A. for power plant divestiture.

Commercial advice (including forward pricing) to a confidential bidder for the New England Electric System divestiture (2800 MW thermal & 1200 MW hydro).

Provided technical / environmental advice to the Government of Pakistan for the 1600 MW Kot Addu plant privatization; developed capacity / energy contract pricing structure adopted in final sales documents.

PROJECT FINANCING

Conducted financial analysis of rival NYU cogeneration projects, including operating cost savings, tax-exempt debt terms, and credit rating impacts; prepared project pro forma and valuation documents for Financial Committee approval and financing.

Worked with NYPA VP of Finance to structure tax-exempt debt terms and repayment schedule for proposed inter-market cable project.

Developed capital structure and cost of capital values for a MISO coal plant divestiture; evaluated depreciation assumptions and alternative (replacement cost less depreciation and comparable sale) valuations in support of state commission testimony.

Advised multiple clients on off-balance sheet financing structures, including tax-exempt operating leases and third-party ownership of CHP and cogen facilities.

Advised clients and conducted studies of merchant gas turbine and combined cycle financing assumptions filed at state commissions and FERC.

Structured non-recourse construction and permanent debt financing for Ocean State Power, the first domestic IPP; liaison between investors and financial advisor.

Developed off-balance sheet financing plans for ThermoElectron cogen projects.

Applied to the US Synthetic Fuels Corporation for price supports and loan guarantees.

Managed Pacific Gas and Electric's $60 million pollution control Industrial Development Bond financing for Geysers dry steam geothermal power plants; structured financing terms with bond counsel, investment banks, and corporate staff.

Recommended financing and contract support structures for Pacific Gas and Electric subsidiaries & joint venture projects, including coal mine, power plants, gas production, and residential conservation.

GAS & FUEL PROJECTS

Estimated capital cost differentials and operational differences for gas-fired and dual-fueled power plants; assessed regional fuel-switching requirements and cost recovery rules for the Eastern Interconnection Planning Collaborative Gas-Electric Study.

Developed integrated gas supply, storage, and forward haul gas project concept for utilities in metropolitan New York / New Jersey to expand winter deliveries.

Evaluated equity return / risk profiles and prepared cash flow forecasts of interstate gas pipelines and storage projects for independent power plants in the Northeast.

Prepared testimony on risk, financing, and capital cost for the Endicott Pipeline Co.

Evaluated throughput and rate impacts on financial returns of competing gas pipeline proposals to support the development of Iroquois Gas Pipeline.

Commercial Advisor to the Pakistan Government for privatization of the Sui Northern Gas Pipeline Company (approx. 200 bcf annual sales with 24,000 km of pipe).

Determined distribution links between major domestic gas production basins and markets to allocate exploration and development funds of Sohio Petroleum.

World Bank advisor for Asia Pacific Ltd. oil storage & pipeline projects, Pakistan.

ENERGY & POWER PLANT OPTIMIZATION

Evaluated contract terms and conditions governing energy options for Nassau County Hub commercial district including cogeneration, spot market purchases, etc.

Assisted NYC industrial firm with cogeneration development; drafting steam purchase, power purchase option, site lease, and development contracts.

Developed cost-effective energy strategy with asset reconfiguration, contract restructuring, and permit modifications for Massachusetts Water Resources Authority; plant now participates in ISO-NE energy and capacity markets.

Implemented direct gas service via Algonquin Gas Transmission and evaluated cogeneration options for Phelps Dodge copper plant in Connecticut.

Developed inside-the-fence cogeneration and fuel strategy for Arizona paper mill.

Identified optimal cogeneration plant configuration and fuel supply for City of Holyoke municipal utility.

FINANCIAL ANALYSIS & VALUATION

Estimated ratepayer damages due to questionable inclusion of costs in the Environmental and Ecological Adjustment component of Cleveland Public Power retail rates for residential and commercial plaintiffs.

Compared power plant economics of dual-fuel capability versus firm transportation supply and documented fuel switching experience for the Eastern Interconnection Planning Collaborative (ISO-NE, PJM, TVA, MISO, and IESO) funded by U.S. DOE.

Financial and business evaluation of proposed electrical microgrid / cogeneration system in Brooklyn NY using innovative non-synchronous interconnection technology.

Assessed gas turbine market dynamics, commercial issues, and financial damages for lawsuit regarding turbine inlet fogging systems for enhancing output and efficiency.

Evaluated intended financing plan and resulting credit strength of proposed new owner of Entergy's merchant nuclear plants, including Vermont Yankee, for the Vermont DPS; prepared information requests and rebuttal testimony.

Prepared cogen investment analysis for Massachusetts Institute of Technology.

Co-authored fair market value appraisals of five 22 MW GWF Bay Area fluidized bed coke-fired power projects and the 209 MW Kalaeloa oil-fired cogeneration plant in support of financial transactions.

Advised lessor on buyout offer of wood-fired plant including future residual value.

Quantified the financial implications of purchasing an undivided equity interest in the River Bend nuclear plant in light of revised operating & maintenance expenses, revised administrative & general expenses, and changing market conditions for PECO Energy.

Evaluated pro forma assumptions and risk / returns of Malaysian power projects.

Reviewed financial feasibility of clean coal demonstration projects for DOE.

Managed steam purchase contract evaluation and internal cogeneration feasibility study for petrochemical producer in The Netherlands.

Proposed project financing options for Elektrenai plant modernization in Lithuania.

Power and fuel negotiation support for Cumbria Power, Ltd., the first English IPP.

Developed economic assumptions, financial pro formas, and equity return / risk profiles for numerous proposed power projects for ThermoElectron and clients.

Prepared long-term financial and rate forecasts of Pacific Gas & Electric for state commission filing.

GENERATION PLANNING / RESOURCE ECONOMICS

Audited Florida Power & Light's resource plan, including fuel, load, and generation.

Techno-economic cogeneration feasibility study for Algonquin Gas Transmission.

Valued existing generating plant based on alternative peaking capacity for Delmarva Power & Light.

Forecasted avoided energy / capacity costs for domestic third-party generators.

Supervised life cycle power plant economic analysis for a Fuel Use Act application.

Compared historic and projected electric use by manufacturing industry for EPRI.

LITIGATION SUPPORT AND EXPERT TESTIMONY

Filed Direct and Supplemental Testimony at the Vermont Public Service Board on forecasted power market, air emission, and electric rate impacts due to renewable energy imports via the proposed 1,000 MW HVDC New England Clean Power Link for TDI-NE's application for a Certificate of Public Good (Docket No. 8400).

Testified before the Maryland Public Service Commission on LAI's comprehensive procurement report and recommended revisions to the Code of Maryland Regulations to implement the Offshore Wind Energy Act of 2013 (Docket RM51).

Submitted Supplemental Testimony and testified on economics and risk allocation of the NSP Maritime Link Compliance Filing, including the proposed Energy Access Agreement, before the Nova Scotia Utility and Review Board (Matter No. M05419).

Submitted Testimony and testified on behalf of the Vermont DPS addressing the reliability, market price, socio-economic, and environmental impacts of Vermont Yankee's potential retirement to the Vermont Public Service Board (Docket No. 7862).

Provided expert witness report on the gas turbine power market and turbine inlet cooling competition in legal malpractice suit concerning inlet fogging systems in the Ninth Judicial Court, Orange County, Florida (Case No. 2011-CA-004008-O).

Submitted expert report on alternative resource options, system reliability, market price, and socio-economic impacts of Vermont Yankee's potential retirement for the Vermont DPS in US District Court, District of Vermont (Civil Action No. 11-cv-99).

Submitted Affidavit to FERC on NYISO Demand Curve Reset parameters (excess capacity, system deliverability upgrades, and cost escalation rate) for Capability Years 2011/12 - 2013/14 on behalf of NYC generators (Docket ER11-2224-0000).

Provided an Expert Report on the Deepwater Block Island offshore wind farm contract price and electric impacts and an Advisory Opinion on regional economic impacts for the Rhode Island Economic Development Corporation; testified before the Rhode Island Public Utility Commission (Docket No. 4185).

Testified before the Virginia State Corporation Commission on behalf of Shell Energy NA regarding DVP's 2009 Integrated Resource Plan (Case No. PUE-2009-00096).

Submitted expert report and testified before the Virginia State Corporation Commission on behalf of Shell Energy NA regarding Dominion Virginia Power's 2007 Solicitation for 2011 Unit Capacity on RFP structure and bid evaluation issues (Case PUE-2008-00014).

Prepared information requests, submitted expert testimony, and testified before the Vermont Public Service Board on behalf of the Vermont DPS regarding the proposed restructuring of Entergy's merchant nuclear generation assets (Docket No. 7404).

Submitted expert report on behalf of generator group; participated in FERC Technical Conference on proposed Reliability Pricing Model mechanism to set PJM market capacity prices (FERC Dockets Nos. EL05-148 and ER05-1410).

Prepared expert report on New York and New England capacity market mechanisms and plant valuation impacts for the Mirant Corporation Equity Committee in US Bankruptcy Court (Case No. 03-46590).

Submitted FERC affidavit regarding gas turbine engineering and economic parameters to reset locational ICAP demand curve; represented NYISO at FERC Technical Conference (FERC Docket No. ER05-428).

Expert witness regarding Salton Sea binary cycle geothermal EPC contract performance and consequential damages based on plant production and market power rates before the American Arbitration Association.

Expert witness testimony for the Bridgeport RESCO waste-to-energy facility at the Connecticut PURA re avoided cost pricing in the deregulated energy market (Docket 99-03-35REO3).

Tax valuation support for gas and electric assets for Yankee Gas Company and The Connecticut Light and Power Company in Connecticut Superior Court (Docket No. CV 95-0072561S).

Expert witness report supporting PECO Energy (Exelon) decision to cancel purchase of equity interest in the River Bend nuclear plant in US District Court for the Middle District of Louisiana (Adversary Proceeding No. 98-477-B-M3).

Provided expert witness report and testified regarding contractual benefits of major coal plant turbine upgrade for Mechanical Plant Services, Inc. based on future power market values in US District Court for the Middle District of Florida, Orlando Division, (Case No. 6:99-CV-76-ORL-22A); accepted as an expert in "power project cost analysis and power price forecasting."

Expert witness regarding economic feasibility, financing, and profitability of Mid-Atlantic Energy's proposed cogeneration plant in West Virginia Circuit Court (Civil Action No. 95-C-214M).

Presented testimony on the relationship of independent power development fees to project capital costs before the American Arbitration Association.

PRESENTATIONS & PUBLICATIONS

Invited Speaker: International Offshore Wind Partnering Forum, Newport, RI, October 2016.

"Can Nuclear Power Survive in Competitive Markets?" lecture at the Hochschule Luzern (HSLU) School of Engineering and Architecture, May 2016

"Competitive Power System Design & Operation" lecture at Zürcher Hochschule für Angewandte Wissenschaften (ZHAW) Department of Applied Sciences, May 2014-2016 and at HSLU 2014-2015.

"A Closer Look at Transmission Drivers in New England," TransForum East Conference, December 2015.

"Electric System Operations and Structures" lecture at Merrimack College, November, 2015.

"Surprising Takeaways from a New Power Market Analysis" article on onshore and offshore wind economics with Dr. Angeliki Rigos, published in North American Windpower, September 2015.

"Wind Power: Economic, Environmental, Technical, and Geopolitical Considerations" lecture at HSLU, May 2015.

Presentation on "Project Application Requirements, Evaluation Criteria, and Selection" to the International Offshore Wind Partnering Forum sponsored by the Business Network for Maryland Offshore Wind, November 13, 2014.

"Power Project Economic Evaluation" lecture at Merrimack College, November 2013.

Co-authored article "Working Jointly to Develop Offshore Wind" on socio-economic benefits and coordinating offshore wind development policies, published in North American Windpower, October 2012.

Speaker on cross-industry panel: "Let's Talk Transmission: Unplugged!" at the NARUC 2012 Summer Committee Meetings, July 2012.

Primary author of "Green Gridworks" lead article on transmission integration of renewable resources, Public Utilities Fortnightly, February 2012.

Panelist at the Northeast Offshore Wind Summit addressing renewable resource penetration and outlook in the ISO-NE electricity market, 2010.

Presentation to NYISO Installed Capacity Working Group on peaker proxy technology / cost / performance, deliverability, site requirements, availability, etc, 2010.

Moderated panel on ISO-NE's Forward Capacity Market mechanism at the Northeast Energy & Commerce Association's 2009 Power Markets Conference.

Gas and electric market interdependency panel moderator at Platt's 4th Annual Northeast Power Forum, 2009.

Sponsor for the Northeast Energy and Commerce and Association conference "Northeast Capacity Markets"; moderator for panel on generation entry / attrition outlook, 2007.

Conference organizer and moderator for "Capacity Markets – Impacts on Assets and Power Pricing" regarding generation and transmission investment in ISO-NE, NYISO, and PJM, 2007.

Conducted workshop "Forecasting Capacity Prices in the Northeast" and moderated panel on generation financing at Infocast Northeast Power Supply Forum, 2006.

"Financing Projects with ICAP Revenues", Infocast Power Financing conference, 2004.

Panel moderator on "New England and Canadian LNG Projects", Infocast Atlantic Coast LNG Conference, 2004.

Speaker, "Power Sales Contract Restructuring Issues", at Infocast Asset Optimization and Portfolio Management Conference, 2003.

Panelist on "Southwest Connecticut Congestion", 10th Annual New England Energy Conference, 2003.

"Fuel and Power Contracting", Int'l District Energy Association Conference, 2002.

"Contract Restructuring", Infocast QF & IPP conference, 2001.

"Successful Valuation and Value-Creation of Transmission Assets", Infocast Electric Asset & Portfolio Valuation conferences, 2001.

"Evaluation of Repowering the Cabot Street Steam Station" using gas turbine technology, International District Energy Association conference, 2001.

"Plant Repowering" at the Infocast Plant Acquisition conference, 2000.

"Equipment Performance Impacts", Infocast Merchant Peaking Plant conference, 2000.

"The Pros and Cons of Repowering" in Competitive Utility, 2000.

"The First Wave" (initial divestiture results) 1998 and "Gas versus Coal" (techno-economic study) 1995, Independent Energy magazine.

"Evaluating Technical and Construction Risk" and "The Due Diligence Process", classes and case studies on for the Infocast Project Finance Institute, 1996-1998.

Non-utility generation and project financing classes at Stone & Webster Utility Management Development Program, 1989-96; General Electric, 1991-94; IBM 1994.

"Self Generation under Competitive Bidding", 1989 Cogen & IPP Congress.

EDUCATION

International Gas Turbine Institute course
Basic Gas Turbine Technology, 1996

Kennedy School (Harvard University) courses
International Political Economy, 1993
International Geopolitics of Oil, 1982

Wharton Graduate School (Univ. of Pennsylvania)
MBA in Finance / Operation Research, 1978

Brown University
Sc.B. in Applied Mathematics / Economics, 1976

MISCELLANEOUS

Member of the Newton Solid Waste Commission, 2011-2015

Board of Directors, Northeast Energy and Commerce Association, 2007-2011.

President and volunteer, Watertown Recycling Center; served on Watertown Trash and Recycling Committee that initiated curbside pickup 1990-1996.

Adjunct faculty lecturer in finance, Golden Gate University, 1979-1980.

Optimum yield resource management, National Oceanic and Atmospheric Administration, 1977.

Member of Mayor's Waterfront Development Committee and Interface: Providence urban design team, 1974-1976.