APPENDIX B

RESOURCE ADEQUACY

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INTRODUCTION

ISO New England (ISO-NE) defines four separate resource adequacy requirements affecting Connecticut: the ISO-NE-wide Installed Capacity Requirement (ICR); two Connecticut requirements under the Transmission Security Analysis (CT TSA) and the Connecticut Local Resource Adequacy (CT LRA) requirement, where the more stringent of the two governs; and the Connecticut requirement in the Locational Forward Reserve Market (LFRM).

This appendix describes the load forecasts that largely drive the first three requirements, then estimates the magnitude of each requirement over the next ten years. Next, the supply of resources is projected in the context of ISO-NE's forward capacity market. This is the most involved part of the analysis because, although there is rich publicly-available data on existing and planned resources, future entry and exit decisions depend primarily on private market participants' decisions that can only be estimated. Finally, resource adequacy is assessed by comparing the projected supply to the requirements. This assessment is performed for a Base Case and for alternative cases reflecting different market conditions.

This appendix also includes a discussion of the reliability implications of reliance on natural gas. The discussion is focused on the key risks associated with reliance on natural gas as well as future monitoring and analytical needs.

ISO NEW ENGLAND'S LOAD FORECAST

All reliability requirements in the ISO are driven by projections of peak demand. Connecticut and ISO-wide reliability requirements are based on ISO's 2013-2022 Forecast Report of Capacity, Energy, Loads, and Transmission (2013 CELT), particularly the load forecast reflecting normal weather ("50/50") and base economic growth conditions for the years 2013 through 2022.[1,2] To forecast peak loads over the entire study period through 2024, the ISO's forecast using the 2021-2022 load growth rates is extrapolated. A more recent version of this ISO-NE report was published during final production of this IRP. That report uses the same load forecasting methodology and reflects only slightly lower loads that would not materially change the 2014 IRP's conclusions.[3]

The ISO publishes several different forecasts to simulate the uncertainty surrounding 10-year forecasts for load. The Base Case uses the ISO's weather-normalized 50/50 demand forecasts that reflect normal weather and base economic growth.[4] This is a "most likely" forecast because

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1 ISO New England Inc., *2013-2022 Forecast Report of Capacity, Energy, Loads, and Transmission*, May 2013. Available at http://www.iso-ne.com/trans/celt/report/2013/2013_celt_report.xls.

2 All Connecticut peak load figures discussed in this section refer to the Connecticut sub-area (ISO zones Norwalk, SW Connecticut, and rest of Connecticut). This excludes a small amount (approximately one percent) of state demand physically in Connecticut but electrically in Western Massachusetts.

3 Ehrlich, David, *2014 CELT/RSP ISO-NE, State, Subarea, and Load Zone Energy and Seasonal Peak Forecast 2014-2023*, presentation to the ISO-NE Planning Advisory Committee, April 29, 2014.

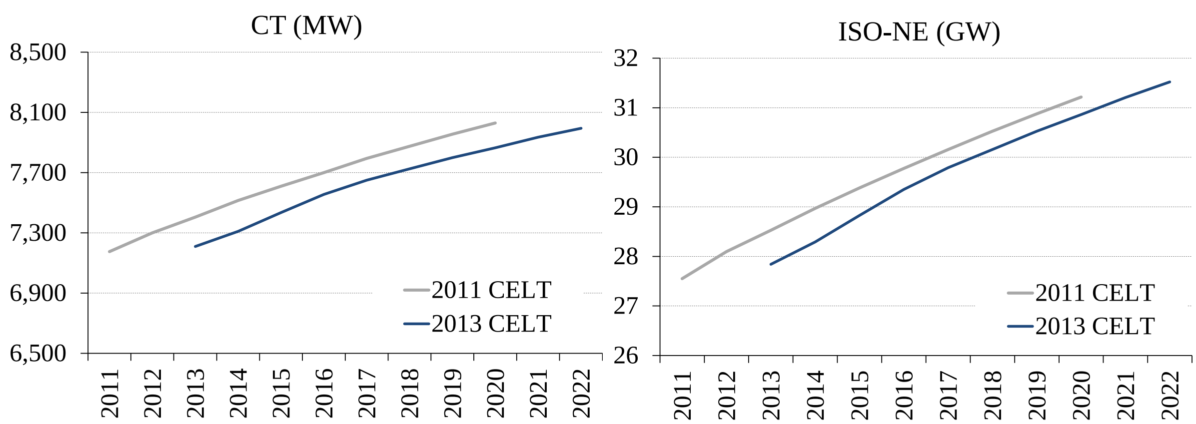
4 The ISO's forecast is a "busbar" forecast, meaning that it reflects the amount needed to be produced at generation sources to serve all load plus losses. These losses are estimated at roughly eight percent, a factor that the ISO uses to gross up metered (customer) load to account for transmission and distribution losses.

it implies that there is a 50% chance the actual load will exceed the forecast and a 50% chance the actual load will be lower than the forecast. Sensitivities are also tested using ISO forecasts that reflect both faster and slower economic growth.

Figure 1 presents the ISO's 2013 CELT 50/50 gross peak load forecasts for the Connecticut sub-area and the ISO, respectively, as well as the corresponding 2011 CELT forecasts used in the 2012 IRP for comparison. The 2013 forecast has declined relative to 2011. Compared to the 2011 forecast, the 2013 forecast for ISO-NE is 685 MW lower in 2013 and 355 MW lower in 2020. Before accounting for changes in other factors, this reduction in the load forecast would increase the capacity surplus in both ISO-NE and CT.

There have been no significant changes to the gross load forecasting methodology since the 2011 CELT forecast used in the 2012 IRP.[5] The gross peak load does not reflect the impact of energy efficiency measures, because those are counted on the supply-side for meeting peak demand and resource adequacy, as discussed in later sections of this appendix.

Figure 1
ISO-NE CELT Gross Peak Load Forecast
2013 vs. 2011 CELT Forecasts



Sources: ISO-NE 2013 CELT Forecast, ISO-NE 2011 CELT Forecast.

CONNECTICUT AND ISO-WIDE RELIABILITY REQUIREMENTS

ISO-NE has developed several requirements to ensure the procurement of sufficient capacity to reliably meet expected load. For Connecticut, the ISO imposes a local sourcing requirement (LSR) to ensure it procures enough capacity within its zone. The LSR is set by the greater (i.e., more stringent) of the probabilistically-calculated Local Resource Adequacy (LRA) and the deterministically-calculated Transmission Security Analysis (TSA). For the ISO, the Installed Capacity Requirement (ICR) is an ISO-wide requirement to meet a one-event-in-ten-years loss-of-load expectation (LOLE). In addition, Connecticut must also ensure that it has enough quick-start capacity located within Connecticut to maintain reliability.

5 ISO New England Inc., *2013 Regional System Plan*, November 7, 2013. See discussion in Section 3.

Connecticut TSA and LRA

All load serving entities (LSEs) in Connecticut must financially support sufficient capacity to meet their peak load share of the ICR which helps the region as a whole meet the ICR. However, the ISO also imposes an additional LSR to ensure that sufficient capacity is *physically located* in a sub-area to maintain local reliability when transmission limitations might prevent outside generation from serving local loads.

The greater of the ISO's two local requirement calculations (TSA and LRA) is explicitly enforced in the capacity market as Connecticut's LSR. The ISO calculates Connecticut's LRA using a probabilistic analysis of expected Connecticut system conditions. Because the recent LRA values are similar to TSA values, and because the LRA is particularly nuanced and difficult to re-calculate given different load, transmission, and resource assumptions, we base our analysis of Connecticut's resource adequacy solely on the TSA to define Connecticut's local needs.[6]

For determining the TSA, the ISO has several methodologies. One methodology is an "operable capacity" analysis. This form of the TSA is essentially the ISO's 90/10 peak load forecast plus the loss of the single largest contingency with one transmission line already out of service. Under this methodology the TSA is expressed in terms of "unforced," or derated, capacity.[7] However, for better comparison with the ISO-wide ICR, which is expressed in terms of total installed capacity, we express the Connecticut TSA in the form of an internal total installed capacity requirement rather than an unforced capacity requirement.

Figure 2 shows the estimated TSA reliability requirement for the Connecticut area in the Base Case. The TSA values for 2015 and 2016 are the latest actual values approved by FERC.[8] The TSA for 2017 is the value proposed by ISO-NE that will be filed with FERC.[9] Values for 2018 and beyond are representative, based on the projected peak load, largest contingency, import limit, and resource characteristics. Rows 5 and 6 of Figure 2 indicate the derate factor used to convert the TSA between a total installed capacity requirement and an unforced capacity requirement (about 7-9%, depending on types of supply resources projected in each year). Row 4 of Figure 2 shows that the Connecticut import limit used in the TSA calculation is projected to change over time. Values for 2015 and 2016 (2,600 MW) reflect the Connecticut import limit assumed in the TSA calculation for FCA6 and FCA7, respectively. The 2017 value (2,800) reflects the Connecticut import limit assumed in the TSA calculation for the FCA8. The higher value in 2017 relative to prior years reflects the impact of the Greater Springfield Reliability Project (GSRP) currently under construction, and portions of the planned Interstate Reliability Project. Starting in 2018, the Connecticut import limit used in the TSA calculation is assumed to

6 In the FCA8 ICR values, the Connecticut TSA is 7,273 MW and the LRA is 7,319 MW. See ISO-NE Proposed ICR Values for the FCA8, available at http://www.iso-ne.com/committees/comm_wkgrps/relblty_comm/relblty/mtrls/2013/sep182013/a5_fca8_hqicc_icr_values

7 Resource capacities eligible to meet the TSA must be reduced to account for an expected rate of forced outages.

8 The 2015 CT TSA is from FCA6 1st ARA, and the 2016 TSA is from FCA7. See ISO-NE Summary of ICR Values, available at http://www.iso-ne.com/markets/othrmkts_data/fcm/doc/summary_of_icr_values%20expanded.xls

9 ISO-NE Proposed ICR Values for the FCA8, available at http://www.iso-ne.com/committees/comm_wkgrps/relblty_comm/relblty/mtrls/2013/sep182013/a5_fca8_hqicc_icr_values

increase to 2,950 MW, due to completion of the remaining portions of the Interstate Reliability Project.

Figure 2
Connecticut Actual and Representative Local Reliability Requirements based on the TSA

			2015 *FCA6*	2016 *FCA7*	2017 *FCA8*	2018 *FCA9*	2019 *FCA10*	2020 *FCA11*	2021 *FCA12*	2022 *FCA13*	2023 *FCA14*	2024 *FCA15*
Connecticut Requirement under the TSA	**[1]**	***(MW)***	**7,341**	**7,489**	**7,273**	**7,217**	**7,307**	**7,383**	**7,470**	**7,538**	**7,609**	**7,680**
Sub-Area 90/10 Peak Load	[2]	*(MW)*	8,072	8,201	8,330	8,410	8,490	8,560	8,640	8,705	8,770	8,836
Reserves (largest contingency)	[3]	*(MW)*	1,225	1,225	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200
Connecticut Import Limit	[4]	*(MW)*	2,600	2,600	2,800	2,950	2,950	2,950	2,950	2,950	2,950	2,950
Existing Resources	[5]	*(MW)*	9,277	9,004	9,768	9,272	9,369	9,437	9,497	9,533	9,588	9,633
Installed Capacity Derate	[6]	*(MW)*	813	797	729	716	727	733	737	737	741	744

Sources and Notes:
[1]: TSA Requirement = ([2] + [3] - [4])/(1 - [6]/[5]).
See page 9 of ISO-NE's September 18, 2013 RC Presentation, *FCA8 ICR and Related Values,* for an example of this calculation.

ISO-NE Installed Capacity Requirement

The Installed Capacity Requirement (ICR) is an ISO-wide requirement to meet a one-day-in-ten-years loss-of-load expectation, which the ISO calculates using a probabilistic analysis of load uncertainty, resource availability, and tie benefits from neighboring regions. An ICR for any given year is updated by the ISO as it receives new information about expected load and system conditions. In this report, we use the most updated information available, based on parameters for FCA8.

Figure 3 shows the ISO-wide ICR used in our analysis. The Net ICR values for 2015, 2016, and 2017 are the latest actual values approved by FERC.[10] Values for 2018 and beyond are representative, based on the pool reserve value of 13.6% included in the 2017 Net ICR and the 2013 CELT 50/50 gross peak load forecast.

Figure 3
ISO-NE Actual and Representative Installed Capacity Requirements

		2015 *FCA6*	2016 *FCA7*	2017 *FCA8*	2018 *FCA9*	2019 *FCA10*	2020 *FCA11*	2021 *FCA12*	2022 *FCA13*	2023 *FCA14*	2024 *FCA15*
ISO-NE 50/50 Peak Load	***(MW)***	**28,825**	**29,350**	**29,790**	**30,155**	**30,525**	**30,860**	**31,205**	**31,520**	**31,838**	**32,160**
Net Installed Capacity Requirement	***(MW)***	**32,771**	**32,968**	**33,855**	**34,270**	**34,690**	**35,071**	**35,463**	**35,821**	**36,183**	**36,548**
Installed Capacity Requirement (adds back HQICCs)	*(MW)*	33,813	34,023	34,923	35,338	35,758	36,139	36,531	36,889	37,251	37,616
HQICCs	*(MW)*	1,042	1,055	1,068	1,068	1,068	1,068	1,068	1,068	1,068	1,068
Other Tie-Benefits	*(MW)*	634	815	802	802	802	802	802	802	802	802
Pool reserve	*(%)*	13.7%	12.3%	13.6%	13.6%	13.6%	13.6%	13.6%	13.6%	13.6%	13.6%

[10] The 2015 Net ICR is from FCA6 1st ARA, the 2016 Net ICR is from FCA7, and the 2017 Net ICR is from FCA8. See ISO-NE Summary of ICR Values, available at http://www.iso-ne.com/markets/othrmkts_data/fcm/doc/summary_of_icr_values%20expanded.xls. Analysis performed prior to FCA9.

Connecticut LFRM Requirement

To meet the fourth reliability requirement considered in this IRP — Connecticut's Locational Forward Reserve Market (LFRM) requirement — both Southwest Connecticut and Greater Connecticut must provide local reserves in the form of non-spinning 30-minute reserves. The ISO's 2013 Regional System Plan (RSP) indicates that through 2017, Southwest Connecticut will have no LFRM requirement. More recent preliminary values for the 2014 RSP indicate that Southwest Connecticut's LFRM requirement could be up to 200-350 MW in the 2015-2018 period, due to high imports into the area.[11] The 2013 RSP also indicates that Greater Connecticut may have a need of up to 900 MW through 2016, with the need declining to up to 600 MW in 2017 following the expected commissioning of the Lake Road-Card line, which would bring the Lake Road generating facility electrically into Connecticut and reduce the need for local reserves.[12, 13]

Projected supply is more than adequate, with 934 MW in Southwest Connecticut, and 1,470 MW available to meet Greater Connecticut needs. Figure 4 shows the resources available to meet each area's requirement under LFRM. Resources in Southwest Connecticut can meet both Southwest Connecticut's requirement and the greater Connecticut requirement.

While local forward reserve requirements in Connecticut are projected to decline, ISO-NE recently increased the region-wide forward reserve requirement for ten-minute non-spinning reserves by 25% to compensate for observed nonperformance of resources with reserve obligations.[14] The increased requirement caused an increase in region-wide forward reserve prices in the Summer 2013, Winter 2013/14, and Summer 2014 forward reserve auctions.[15] We assume that forward reserve prices will remain constant in real terms at the levels observed in the Winter 2013/14 auction, based on data available at the time of the 2014 IRP analysis. Although prices did increase in Summer 2014, total LFRM market-clearing quantities are too low (about 700 MW system-wide for Summer 2014) to materially change the 2014 IRP's analysis or its conclusions.

[11] Zeng, Fei, *New England Regional System Plan (RSP2014) Representative Future Locational Forward Reserve Requirements,* presentation to the ISO-NE Planning Advisory Committee, June 19, 2014.

[12] ISO-NE 2013 RSP, Section 4.2.2.

[13] More recent preliminary values for the 2014 RSP indicate similar requirements, though slightly higher. Greater Connecticut's LFRM requirement could be up to 1,000 MW in 2016, and up to 700 MW in 2017 and 2018. Zeng, Fei, *New England Regional System Plan (RSP2014) Representative Future Locational Forward Reserve Requirements*, presentation to the ISO-NE Planning Advisory Committee, June 19, 2014.

[14] ISO-NE 2013 RSP, Sections 4.2.1.1 and 4.2.1.2.

[15] ISO-NE Forward Reserve Auction Results Report, available at http://www.iso-ne.com/markets/othrmkts_data/res_mkt/summ/index.html.

Figure 4
Resources Available to Meet SWCT and Greater Connecticut LFRM Requirements

Unit Name	Unit Status	RSP Area	Unit Type	In-Service Date	Winter Claimed Capability *(MW)*	Summer Claimed Capability *(MW)*
BRANFORD 10	Existing	SWCT	GT	1-Jan-69	21	16
BRIDGEPORT HARBOR 4	Existing	SWCT	GT	1-Oct-67	17	17
COS COB 10	Existing	NOR	GT	1-Sep-69	23	19
COS COB 11	Existing	NOR	GT	1-Jan-69	23	19
COS COB 12	Existing	NOR	GT	1-Jan-69	23	19
COS COB 13	Existing	NOR	GT	29-May-08	23	19
COS COB 14	Existing	NOR	GT	29-May-08	23	19
DEVON 10	Existing	SWCT	GT	1-Apr-88	19	14
DEVON 11	Existing	SWCT	GT	1-Oct-96	39	29
DEVON 12	Existing	SWCT	GT	1-Oct-96	38	29
DEVON 13	Existing	SWCT	GT	1-Oct-96	39	30
DEVON 14	Existing	SWCT	GT	1-Oct-96	40	30
DEVON 15	Existing	SWCT	GT	12-Jul-10	49	47
DEVON 16	Existing	SWCT	GT	28-Jun-10	49	47
DEVON 17	Existing	SWCT	GT	15-Jun-10	49	47
DEVON 18	Existing	SWCT	GT	9-Jun-10	49	47
NORDEN 1	Existing	NOR	IC	26-Feb-09	2	2
NORDEN 2	Existing	NOR	IC	26-Feb-09	2	2
NORDEN 3	Existing	NOR	IC	26-Feb-09	2	2
PIERCE STATION	Existing	SWCT	GT	1-Oct-07	95	74
ROCKY RIVER	Existing	SWCT	PS	1-Jan-28	28	29
WALLINGFORD UNIT 1	Existing	SWCT	GT	31-Dec-01	48	42
WALLINGFORD UNIT 2	Existing	SWCT	GT	7-Feb-02	48	42
WALLINGFORD UNIT 3	Existing	SWCT	GT	31-Dec-01	48	42
WALLINGFORD UNIT 4	Existing	SWCT	GT	23-Jan-02	47	42
WALLINGFORD UNIT 5	Existing	SWCT	GT	7-Feb-02	49	42
WATERBURY GENERATION FACILITY	Existing	SWCT	GT	21-May-09	99	96
WATERSIDE POWER	Existing	NOR	GT	1-May-04	70	69
SW Connecticut (including Norwalk) Subtotal:					**1,063**	**934**
FRANKLIN DRIVE 10	Existing	CT	GT	1-Nov-68	21	15
MIDDLETOWN 10	Existing	CT	GT	1-Jan-66	19	0
MIDDLETOWN 12	Existing	CT	GT	24-Jun-11	49	47
MIDDLETOWN 13	Existing	CT	GT	23-Jun-11	49	47
MIDDLETOWN 14	Existing	CT	GT	1-Jun-11	49	47
MIDDLETOWN 15	Existing	CT	GT	1-Jun-11	49	47
MONTVILLE 10 and 11	Existing	CT	IC	1-Jan-67	5	5
NEW HAVEN HARBOR UNIT 2	Existing	CT	GT	30-May-12	49	43
NEW HAVEN HARBOR UNIT 3	Existing	CT	GT	30-May-12	49	43
NEW HAVEN HARBOR UNIT 4	Existing	CT	GT	30-May-12	49	43
NORWICH JET	Existing	CT	GT	1-Sep-72	19	15
NORWICH WWTP	Existing	CT	IC	29-May-08	2	2
SO. MEADOW 11	Existing	CT	GT	1-Aug-70	47	36
SO. MEADOW 12	Existing	CT	GT	1-Aug-70	48	38
SO. MEADOW 13	Existing	CT	GT	1-Aug-70	48	38
SO. MEADOW 14	Existing	CT	GT	1-Aug-70	46	37
TORRINGTON TERMINAL 10	Existing	CT	GT	1-Aug-67	21	16
TUNNEL 10	Existing	CT	GT	1-Jan-69	22	17
Rest-of-Connecticut Subtotal:					**640**	**536**
Available for SW Connecticut LFRM:					**1,063**	**934**
Available for Greater Connecticut LFRM:					**1,703**	**1,470**

Sources and Notes:
Data from 2013 CELT Report.
Unit Types Include: Gas Turbine (GT), Internal Combustion (IC), and Pumped Storage (PS) units.
RSP Areas included are Southwest Connecticut (SWCT), Norwalk (NOR) and Rest of Connecticut (CT).
Norwalk Harbor 10 and John Street are excluded due to their planned retirement.

EXISTING, PLANNED, AND ASSUMED FUTURE RESOURCES

To meet the ICR and CT TSA reliability requirements we first consider "known" generating and demand-side resources, which are either existing or planned based on currently available information. We also consider assumed future resources such as projected renewable additions. This section describes all such assumptions; the subsequent section develops adjustments to these assumptions based on economic considerations.

Existing Generation

Existing generation online as of May 31, 2013 is documented in the ISO's 2013 CELT Report. As of May 31, 2013 there are 7,897 MW of available generation resources in the Connecticut sub-area and 31,759 MW available ISO-wide to meet reliability requirements.[16]

Non-Renewable Additions and Retirements

With the exception of assumed new renewable generation, the only projects that are counted in this IRP for meeting future reliability needs are those that have cleared in FCM. Non-renewable planned additions include the 674 MW Footprint combined-cycle plant in the NEMA-Boston area, and a 48 MW uprate at the Northfield Mountain pumped storage facility. Both of these projects cleared in FCA7.[17]

The planned retirement of several units in ISO-NE is incorporated in the analysis based on publicly-available information. Figure 5 summarizes existing units which have announced their plans to retire, including Brayton Point, Vermont Yankee, Salem Harbor, Norwalk Harbor, and several smaller units. With the exception of the derates to Stony Brook, all of these units submitted non-price retirement requests to ISO-NE.[18] Non-price retirement requests are irrevocable requests to retire a resource, and resource owners can elect to retire their resources even if the request is rejected for reliability reasons.[19] Brayton Point's non-price retirement request was rejected by ISO-NE in December 2013, and in January 2014 ISO-NE was notified of the plant's intention to retire by June 1, 2017.[20] Stony Brook submitted a static de-list bid in FCA7. Overall, these retirements contribute to a substantially tighter supply-demand outlook than has been observed in recent years.

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16 Capacity online is documented in the ISO-NE, *2013-2022 Forecast Report of Capacity, Energy, Loads and Transmission*, May 1, 2013 ("2013 CELT Report"). In the 2013 CELT Report, capacity at Bridgeport Harbor 2 is not included as existing capacity, i.e., that unit is given a zero Seasonal Claimed Capability. The more recent CELT report shows 7,627 MW in Connecticut and 31,173 MW region-wide available in summer 2014. Most of the difference in system-wide capacity is due to retirements already accounted for in the 2014 IRP.

17 ISO-NE FCA7 auction results, available at http://www.iso-ne.com/markets/othrmkts_data/fcm/cal_results/ccp17/fca17/index.html.

18 ISO-NE Status of Non-Price Retirement Requests, available at http://www.iso-ne.com/genrtion_resrcs/reports/sts_non_retrmnt_rqst/index.html.

19 ISO-NE Overview of New England's Wholesale Electricity Markets, p.8. Available at http://www.iso-ne.com/pubs/spcl_rpts/2013/markets_overview_051513_final.pdf.

20 This letter can be accessed on the ISO-NE website: http://www.iso-ne.com/genrtion_resrcs/reports/non_prc_retremnt_lttrs/2013/brayton_letter_to_iso_ne_1_27_14.pdf.

Figure 5
Planned Generation Retirements

Unit(s)	Type(s)	Retirement/Derate	2013 CELT Capacity *(MW)*
Brayton Point	Coal, Oil	Retirement	1,535
Vermont Yankee	Nuclear	Retirement	600
Salem Harbor	Coal, Oil	Retirement	584
Norwalk Harbor	Oil	Retirement	342
Lowel Cogeneration Plant	Gas/Oil	Retirement	27
Kendall Steam	Gas	Derate	25
MERC	Refuse	Retirement	17
Stony Brook	Gas/Oil	Derate	13
Medway Diesels 1-4	Oil	Retirement	7
John Street 3-5	Oil	Retirement	6
Bar Harbor Diesels 1-4	Oil	Retirement	4
Bridgeport Harbor 2	Oil	Retirement	0
Total			**3,160**

Sources and Notes:
Capacity is as listed in 2013 CELT, for consistency with existing capacity.
With the exception of the Stony Brook derates, all units submitted NPRRs.
The Stony Brook derate is based on its FCA 7 Static Delist Bid.

In addition to the planned retirements listed above, three plants totaling 181 MW (Mount Tom, Covanta West Enfield, and Covanta Jonesboro) had dynamic de-list bids accepted in FCA7. We assume that these units will mothball during the FCA7 commitment period, but we do not assume that they will retire permanently.[21]

Demand-Side Resources

Demand-side resources include Active Demand Resources (Active DR), and Passive Demand Resources (Passive DR).

Active Demand Resources

Region-wide, the amount of cleared Active DR declined by 868 MW between FCA6 and FCA7, and a further 212 MW of Active DR resources that had cleared in FCA7 submitted non-price retirement requests to ISO-NE in advance of FCA8. For the 2014 IRP, we assume that Active DR remains at levels that were anticipated for FCA8: 333 MW in Connecticut and 904 MW in the total ISO-NE system, as shown in Figure 6. Actual FCA8 results, released prior to final production of this IRP, shows higher values: 380 MW in Connecticut and 1,080 MW in the total ISO-NE system, or about 200 MW more system-wide.

[21] More recent market data shows that, in FCA8, Mount Tom had an accepted static de-list bid, and the Covanta units cleared the auction.

Figure 6
Summary of Active Demand Response Resources

	CT				ISO-NE			
	FCA6 Cleared *(MW)*	FCA7 Cleared *(MW)*	FCA8 NPRRs *(MW)*	FCA7 Less FCA8 NPRRs *(MW)*	FCA6 Cleared *(MW)*	FCA7 Cleared *(MW)*	FCA8 NPRRs *(MW)*	FCA7 Less FCA8 NPRRs *(MW)*
Real Time Demand Response	289	211	(10)	201	1,385	854	(202)	652
Real Time Emergency Generation	185	143	(10)	133	600	262	(10)	252
Total Active DR	474	354	(20)	333	1,985	1,117	(212)	904

Sources and Notes:
NPRR: non-price retirement request.
FCA6 and FCA7 auction results from ISO-NE, and FCA8 Non Price Retirement Requests from ISO-NE.
NPRRs listed for FCA8 include only the resources which cleared in FCA7.
Quantities are shown grossed up to generator busbar.
Analysis performed prior to FCA8 (and FCA9).

Passive Demand Resources

While there have not been significant changes to the gross load forecasting methodology in the 2013 CELT forecast, there have been substantial changes to the forecast of Passive DR and net load. In the 2011 CELT forecast used for the 2012 IRP, the ISO held future Passive DR levels constant at the level cleared in forward capacity auctions, and did not forecast additional quantities of Passive DR beyond those levels. In the 2013 CELT forecast, however, the ISO explicitly forecasts growth in Passive DR beyond FCA levels. In our analysis of resource adequacy we rely on this forecast of passive demand resources for all New England states aside from Connecticut.[22]

The 2013 CELT forecast of Passive DR from 2013 to 2016 reflects resources cleared in FCA4 to FCA7, adjusted slightly for ISO participation and termination values. The forecast from 2017 to 2022 reflects ISO-NE's 2013 Energy Efficiency Forecast, which is based on budgets for state-regulated utility programs and is part of an ongoing effort to analyze the long-term impacts of state-sponsored energy-efficiency programs on future demand.[23] In our analysis of resource adequacy we rely on this forecast of Passive DR for all New England states aside from Connecticut, as shown in Figure 7 below.[24] During final production of the 2014 IRP, the ISO-NE and its stakeholders produced an updated 2014 Energy Efficiency Forecast.[25] The 2014 report assumes more energy efficiency compared to the 2013 prior report. In all New England states aside from Connecticut, the 2014 report projects about 300 MW more energy efficiency by 2022.

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22 We note that while there may still be issues caused by the impact of energy efficiency growth embedded in the pre-2006 historical data used in the CELT load forecast, the impact is reduced relative to the impact in the 2012 IRP because of the inclusion of two more years of recent historical data.

23 See ISO-NE's Final 2013 Energy Efficiency Forecast 2016-2022, available at http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2013/mar212013/a2_energy_efficiency_forecast.pdf, and the ISO-NE 2013 RSP, Section 3.2.

24 The energy efficiency forecast ends in 2022, and we assume that the quantity of passive demand resources is constant at 2022 levels in 2023 and 2024.

25 ISO New England, Inc. System Planning, ISO-New England Energy Efficiency Forecast Report for 2018-2023, June 3, 2014.

In Connecticut, energy efficiency funded by the recent expansion of the system benefits charge is included in our resource adequacy analysis in addition to the levels reflected in ISO-NE's forecast, as described in more detail in Appendix C (Energy Efficiency). The projected amount of energy efficiency in Connecticut is summarized in Figure 7.

Figure 7
Summary of Passive Demand Resources

		2015 *FCA6*	2016 *FCA7*	2017 *FCA8*	2018 *FCA9*	2019 *FCA10*	2020 *FCA11*	2021 *FCA12*	2022 *FCA13*	2023 *FCA14*	2024 *FCA15*
CT Passive DR	*(MW)*	475	522	567	609	649	687	723	758	791	822
Rest of ISO-NE Passive DR	*(MW)*	1,170	1,218	1,406	1,584	1,750	1,906	2,054	2,191	2,191	2,191
Total	*(MW)*	1,645	1,740	1,973	2,193	2,399	2,593	2,777	2,949	2,982	3,013

***Figure 7 Sources and Notes*:**

Rest of ISO-NE data from ISO-NE 2013 CELT Forecast.
2013-2016 values are adjusted for ISO participation/termination values and therefore do not exactly match FCA results.
Quantities are shown grossed up to generator busbar.
Analysis performed before FCA8.

Net Imports from Outside New England

Known imports include external generating resources cleared in the FCA6 and FCA7. In FCA6 1,924 MW of imports cleared for the 2015/16 delivery year, and in FCA7 1,830 MW cleared for the 2016/17 delivery year. Imports are assumed to remain constant at the level cleared in FCA7 through 2024. More recent capacity market data shows only 1,237 MW imports cleared in FCA8, or about 600 MW fewer imports than what is assumed in the 2014 IRP. It is unclear why these resources dropped out of the capacity market at higher prices, and remains to be seen whether they will re-enter the market in future auctions. Overall, we do not expect this result to materially affect the 2014 IRP's analysis of resource adequacy or conclusions, due to offsetting *underestimates* of demand-side resources described previously (about 200 MW Active DR and about 300 MW energy efficiency outside of Connecticut).

One generating unit within ISO-NE, J. Cockwell 1, has de-listed 100 MW in the capacity market as a firm export. This export reflects the unit's long-term contract with Long Island Power Authority to deliver power on the Cross Sound Cable. The current export contract extends to 2021, and it is assumed that this contract will be renewed and continue through 2024.

Renewable Generation Additions

A substantial quantity of renewable generation is projected to be developed during the study period, as documented in detail in Appendix D (Renewable Energy). The impact of renewable generation additions on resource adequacy will vary by resource type, and the following sections summarize the additions in three broad categories: (1) renewable resources without capacity supply obligations; (2) renewable resources with capacity supply obligations; and (3) renewable distributed generation resources. More recent market data on planned new renewables are not expected to affect the resource adequacy analysis described in this appendix,[26] but are accounted for in the renewables supply/demand balance described in Appendix D (Renewable Energy).

Renewable Resources without Capacity Supply Obligations

Under ISO-NE's Minimum Offer Price Rule, several types of renewable resource additions are unlikely to clear in the Forward Capacity Market. ISO-NE's Minimum Offer Price Rule (MOPR) is aimed at preventing buyer-side exercise of market power, and works by subjecting all new entrants to a minimum offer price. The minimum offer price is set based on a competitive benchmark, the Offer Review Trigger Price (ORTP), which defined for each resource type. Offers below the ORTP must be approved by the Independent Market Monitor.[27]

In ISO-NE's 2013 ORTP study, conducted by *The Brattle Group*, costs for new solar photovoltaics (PV), offshore wind, and biomass resources were too high to support an ORTP value below the auction starting price.[28] In developing the 2014 IRP, these resource types were considered very unlikely to clear the capacity market, barring favorable unit-specific costs that are substantially below the costs estimated in the ORTP analysis. We therefore report the capacity contribution from these resources types for informational purposes, but do not include them in our core resource adequacy analysis. A critical component of the demand curve filing was a proposed renewable exemption that would allow a limited quantity of certain new renewable resources to offer their capacity in the FCA at prices below the associated Offer Review Trigger Prices ("ORTP"). On May 30, 2014, FERC accepted the ISO-NE proposed regional demand curve for New England, including the exemption for renewable resources. Therefore, some of the distributed renewables (mostly distributed solar in Massachusetts and Connecticut, and some fuel cells in Connecticut) that this IRP projected to develop but not count toward resource adequacy requirements might help meet the region's capacity need under the new exemptions.

Figure 8 summarizes the capacity value of renewable resource additions in New England without capacity supply obligations. Offshore wind is assumed to have a capacity value of 19% of nameplate capacity, and solar PV is assumed to have a capacity value of 30% of DC nameplate capacity.[29] Figure 8 includes only the capacity value of grid-connected solar PV. The resource adequacy impacts of distributed solar PV are discussed later in this section.

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26 Due to relatively low capacity values towards resource adequacy, for every MW of nameplate renewables.

27 2013 Offer Review Trigger Prices Study, Section I. Samuel Newell, J. Michael Hagerty, and Quincy Liao, prepared for ISO-NE.

28 2013 Offer Review Trigger Prices Study, Section II.A.2.

29 2013 Offer Review Trigger Prices Study, and ISO-NE Distributed Generation Forecast Working Group Kickoff Meeting Presentation, p.14, available at http://www.iso-ne.com/committees/comm_wkgrps/othr/distributed_generation_frcst/2013mtrls/dgfwg_isoslides_final_clean.pdf.

Figure 8
Capacity Value of Renewable Resource Additions in New England without Capacity Supply Obligations

		2015 *FCA6*	2016 *FCA7*	2017 *FCA8*	2018 *FCA9*	2019 *FCA10*	2020 *FCA11*	2021 *FCA12*	2022 *FCA13*	2023 *FCA14*	2024 *FCA15*
Offshore Wind	*(MW)*	0	69	69	75	75	75	75	75	75	75
Grid-Connected Solar PV	*(MW)*	21	29	36	45	53	60	61	61	62	62
Biomass	*(MW)*	129	129	129	129	129	129	129	129	129	129
Total	*(MW)*	150	226	234	248	257	263	264	265	265	266

Figure 8 Sources and Notes:
Projected quantities of resource additions are documented in Appendix D (Renewable Energy). We assume that solar PV's capacity value is 30% of its DC nameplate rating, and that offshore wind's capacity value is 19% of its nameplate capacity. In addition to the resources summarized above, we also assume that the onshore wind additions described in this section will not have capacity supply obligations prior to FCA9. We assume that these resources will not clear the FCM until FCA9 because the qualification period for FCA8 has already concluded. Analysis performed prior to FCA8.

Renewable Resources with Capacity Supply Obligations

The ORTP value for onshore wind additions is $14. However, onshore wind additions are expected to clear in the Forward Capacity Market as part of the yearly 200MW ORTP exemption. Therefore, the capacity contribution from onshore wind additions is included in the resource adequacy analysis.

As documented in Appendix D (Renewable Energy), 822 MW of new onshore wind resources are projected to be developed during the study period. Onshore wind is assumed to have a capacity value of 13% of nameplate capacity, which is consistent with the estimated summer claimed capacity value for onshore wind used in the ORTP analysis.[30] This implies a capacity value of 107 MW for these additions.[31]

Renewable Distributed Generation Resources

A substantial quantity of new distributed generation (DG) resources is anticipated in the region, particularly in the form of distributed solar photovoltaic generation. While these additions will impact resource adequacy in the region, the specific nature of the impact and its recognition in ISO-NE's resource adequacy planning process remains very uncertain.

Distributed generation resources are directly connected to end-use customer loads, and reduce the amount of energy that otherwise would need to be produced by grid-connected capacity resources.[32] ISO-NE has begun the process of developing a distributed generation forecast and

[30] 2013 Offer Review Trigger Prices Study, Section V.A.
[31] We note that while the onshore wind additions are projected to begin operation by 2017, we assume that they will not clear the FCM until FCA9 (2018/19), because the qualification period for FCA8 has already concluded.
[32] ISO-NE Planning Advisory Committee Presentation, Update on Solar PV and Other DG in New England, p.7., available at http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2013/jun192013/a7_solar_dg_update.pdf.

incorporating that forecast into its long-term reliability planning process.[33] Per communication with ISO-NE staff, we understand that it is possible that this process will result in the ISO reducing the long-term load forecast used in the calculation of the installed capacity requirement to reflect the reduction in peak load caused by forecast future DG resources. Any reduction in the load forecast, however, would likely be based on a conservative forecast of the quantity of DG resources, and the impact of the forecasted quantity of DG on the load forecast may be derated to reflect uncertainty. Furthermore, it is unclear what the impact of intermittent DG resources such as solar PV would be in the probabilistic analysis used to determine the ICR. Due to the substantial uncertainty at the time of the 2014 IRP's analysis surrounding the future treatment of DG in the ISO's planning processes, we illustrate the potential magnitude of the impact of DG on the ICR, but do not include it in our core resource adequacy analysis. We note that more specific details regarding the treatment of DG will likely be developed by ISO-NE in the near-term, but we are not able to account for them in this analysis.

Figure 9 shows our estimate of the potential reduction in the ISO-NE ICR and CT TSA in FCA9 and beyond due to the peak load reduction from distributed renewable resource additions. We assume that solar PV's contribution to summer peak load is 30% of its DC nameplate capacity.[34] We emphasize that this estimate is only informational, that it is not included in our core resource adequacy analysis, and that any reduction in reliability requirements would likely be lower than the values we present if the ISO's forecast of the quantity of DG resources or their impact on reliability requirements is conservative.

33 ISO-NE Distributed Generation Forecast Working Group Kickoff Meeting Presentation, available at http://www.iso-ne.com/committees/comm_wkgrps/othr/distributed_generation_frcst/2013mtrls/dgfwg_isoslides_final_clean.pdf.

34 The summer seasonal claimed capacity rating of solar PV is approximately 30% of the DC nameplate rating, and summer SCC values serve as a reasonable estimate of PV's contribution to summer peak load at low penetration levels. See ISO-NE Distributed Generation Forecast Working Group Kickoff Meeting Presentation, p.14, and ISO-NE Planning Advisory Committee Presentation, Update on Solar PV and Other DG in New England, p.30.

Figure 9
Potential Reduction in ISO-NE Net ICR and CT TSA from Distributed Renewable Additions

		2015 *FCA6*	2016 *FCA7*	2017 *FCA8*	2018 *FCA9*	2019 *FCA10*	2020 *FCA11*	2021 *FCA12*	2022 *FCA13*	2023 *FCA14*	2024 *FCA15*
Potential Reduction in ISO-NE ICR											
From Distributed Solar PV	*(MW)*	0	0	0	499	596	668	679	685	691	697
From Distributed Fuel Cells	*(MW)*	0	0	0	95	95	95	95	95	95	95
Total	*(MW)*	0	0	0	594	691	763	774	781	787	793
Potential Reduction in CT TSA											
From Distributed Solar PV	*(MW)*	0	0	0	127	159	164	170	175	180	186
From Distributed Fuel Cells	*(MW)*	0	0	0	91	91	91	91	91	91	91
Total	*(MW)*	0	0	0	218	250	255	260	266	271	277

Sources and Notes:
Projected quantities of resource additions are documented in Appendix D (Renewable Energy).
We assume that solar PV's contribution to summer peak load is 30% of its DC nameplate capacity.
Analysis performed prior to FCA8 but after the NICR and other FCA8 auction parameters were determined.

PROJECTED ECONOMIC RETIREMENT, ENTRY, AND CHANGES IN ACTIVE DR

Most of the existing and potential capacity supply in New England is controlled by market participants. Their exit and entry decisions can only be projected by modeling their financial decisions, which are presumably based on their expected costs and market-based revenues. This section describes how the IRP simulates such decisions, including how costs are estimated, and how energy and capacity revenues are projected.

Capacity Market Modeling

The Brattle Group's capacity market model simulates ISO-NE capacity market auctions and economic entry/exit decisions simultaneously, since the capacity prices both influence individual economic decisions *and* reflect the combined results of those decisions. In the model, the demand for capacity is given by ISO-NE NICR projections. Supply includes most existing/planned generation bidding as price-takers, offering capacity at a price of zero and accepting whatever price results. Retirement candidates, Active DR resources, and potential new entrants submit bids that reflect their net avoidable going-forward costs.

The model solves for a capacity price trajectory for the years 2017-2024. Prices are set by the bid price of the marginal unit (a retirement or mothball candidate, Active DR, or new entrant). At the "optimum," each generating unit is making profit-maximizing short-term decisions (operate versus mothball) and long-term decisions (invest in required environmental controls versus retire). DR is similarly making annual profit-maximizing decisions, as described below.

The capacity model is also linked to the DAYZER energy market model: supplier entry and exit decisions and their capacity market bids depend on their expected energy margins. Likewise, the energy market analysis relies on retirement and new generic build results from the capacity market analysis. To achieve internal consistency, the two models are run iteratively until they are consistent with each other.

Economic Analysis of Existing Units' Retrofit vs. Retirement Decisions

Decision Framework

In determining whether a generation unit would continue to operate or retire, we consider the net present value (NPV) of its going-forward revenues and costs. Revenues include capacity market revenues from the capacity model, and energy margins estimated using the DAYZER model. Going-forward costs include annual fixed operating and maintenance (FOM) costs, and the capital costs of any required retrofits needed to comply with environmental regulations.

The NPV analysis follows the standard all-equity, after-tax, discounted cash flow methodology: calculate all-equity cash flows for each year, then discount them at the after-tax weighted average cost of capital (ATWACC). Because the ATWACC accounts for the cost of equity, and the cost of debt including the debt tax shield, the annual cash flows need not account for interest payments or their effect on taxes, hence the name "all-equity cash flows."[35] The after-tax weighted average cost of capital (ATWACC) assumed in the capacity model is 7.2%, taken from ISO-NE's 2013 ORTP study conducted by *The Brattle Group*.[36] Tax rates are a combination of federal and state income taxes that differ for each state in ISO New England.[37] The final tax rate accounts for a federal income tax rate of 35% and an average state tax rate of 8.6% (simple average state tax rate across all modeled units).[38]

Each unit faces a two-part decision: (1) in each year would it be better to operate and incur any required capital costs or mothball, and (2) given the long-term outlook would it be better to permanently retire?

- **Mothball versus operate:** Prior to making a decision on permanent retirement, some units may find it more economic to mothball in a given year in order to either delay incurring major capital costs or to avoid losses in years with extremely low capacity prices. The retirement analysis includes as an initial step a year-by-year assessment of unit decisions to either mothball or operate. The annual cost to mothball a unit is assumed to be one-half of the ordinary fixed operating and maintenance (FOM) cost that the unit incurs on an ongoing basis.
- **Permanent retirement:** Using the results of the annual mothball versus operate decision, we calculate each unit's annual net revenue including only the cost to

[35] For example, see p. 473 of Brealey, R., S. Myers, and F. Allen. (2010) *Principles of Corporate Finance.* McGraw-Hill.

[36] The ATWACC developed for ISO-NE's 2013 ORTP analysis assumed a PPA for non-capacity revenues, such that a project would have somewhat less risk than a pure merchant generation project. A pure merchant ATWACC would be somewhat higher but has not been quantified for this analysis.

[37] Federal income tax rate is 35%. State income tax rates are 9.0% for CT, 9.0% for RI, 8.5% for NH, 8.5% for VT, 8.93% for ME, and 8.0% for MA. See http://www.taxfoundation.org/taxdata/show/230.html.

[38] The total income tax is $8.6\% + (1 - 8.6\%) \cdot 35\% = 40.6\%$.

mothball in a mothball year, and during operations the capital cost of assumed emissions control installation if required, plus net operating costs.

Assumptions on Environmental Retrofit Costs

Appendix E (Environmental Regulations Potentially Affecting Electric Generation Units in New England) documents all assumptions on retrofits needed to comply with environmental regulations, primarily focused on the Mercury and Air Toxics Standards (MATS).[39] Capital costs needed for MATS compliance are incurred in 2015, and upgrade costs cannot be delayed or avoided. We assume that that retrofits required for MATS can still drive retirement decisions, even though capacity commitments already made in FCA6 and FCA7 extend beyond the 2015 compliance deadline. If net revenues are not high enough to offset the capital investment in required retrofits, units with capacity commitments in FCA6 and FCA7 could buy back their obligations in reconfiguration auctions and retire in 2015. Retrofit costs are estimated based on EPA documentation, and vary depending on plant size and heat rate.[40] Assumed unit-specific costs and upgrades are documented in Appendix E.

Assumptions on FOM Costs

FOM costs include property taxes, plant insurance, facility fees for operating labor and minor maintenance, and asset management costs. Plant-specific FOM costs are represented by data provided by Ventyx, as summarized in Figure 10.

39 That appendix provides unit-specific information based on the following assumptions: Coal Units need activated carbon injection (ACI) as well as either a fabric filter (FF) or a cold ESP for mercury controls. Wet flue gas desulfurization (FGD), dry FGD, or dry sorbent injection (DSI) is needed to control acid gases. The final version of MATS included an exemption for oil-fired units with a capacity factor below 8%. Oil-fired units in New England have recently operated with capacity factors well below 8%, and are projected to continue to operate with capacity factors below 8% in the DAYZER simulations. We therefore do not model MATS-related retrofit costs for oil-fired units.

40 For coal unit costs see http://www.epa.gov/airmarkets/progsregs/epa-ipm/docs/suppdoc.pdf and http://www.epa.gov/airmarkets/progsregs/epa-ipm/docs/SuppDoc410MATS.pdf.

Figure 10
Plant-Specific FOM Costs

Name	State	Capacity *(MW)*	FOM *($/kW-y)*
Bridgeport Harbor 3	CT	383	$38
Middletown 2-4	CT	751	$14
Montville 5&6	CT	486	$13
New Haven Harbor	CT	448	$15
Canal 1&2	MA	1086	$18
Cleary 8	MA	25	$15
Kendal Steam	MA	28	$14
Mount Tom	MA	141	$35
Mystic 7	MA	560	$15
West Springfield 3	MA	94	$15
Yarmouth 1-4	ME	818	$11
Merrimack 1&2	NH	438	$64
Newington 1	NH	400	$20
Schiller 4&6	NH	95	$39

***Figure 10 Sources and Notes*:**
Ventyx, The Velocity Suite.Ventyx estimates these costs based on FERC Form 1 records when available, but costs are estimated based on unit type, age, and state when unit-specific data is not available. These estimates should therefore be considered as approximate.

New Entry Analysis

New generation is assumed to be built when market revenues are sufficient to cover the levelized Cost of New Entry (CONE). The CONE estimates for combustion turbines and combined cycle plants in ISO-NE's 2013 Offer Review Trigger Price study are used in this analysis. Costs considered in this study include capital costs (*e.g.*, equipment, engineering, procurement and construction costs, land, *etc.*) and fixed operation and maintenance costs (*e.g.*, property tax, insurance, *etc.*). A summary of costs is shown in Figure 11. Figure 12 shows the corresponding plant characteristics. We note that the combined cycle plant would be compliant with the EPA's proposed carbon pollution standard for new power plants, and that the combustion turbine would be exempt from the standard if it operated with a capacity factor of less than 33%.[41]

We assume that merchant generators will develop the technology with the lowest net CONE (*i.e.*, CONE less energy margins and ancillary service revenues). We find that the combined cycle technology is more economic than the combustion turbine in all cases examined, due to its substantially lower capital costs and lower heat rate.

[41] Under the proposed standard, large natural gas fired units would be required to meet a standard of 1,000 lb CO_2/MWh. Simple-cycle turbines with a capacity factor of less than 33% would be exempt. See http://www2.epa.gov/sites/production/files/2013-09/documents/20130920proposal.pdf.

Figure 11 shows a levelized gross CONE of $142/kW-year, or about $12/kW-month, for a new combined cycle plant. During production of the 2014 IRP report FERC approved a demand curve for future capacity auctions, which included an updated study on CONE. Updated values estimate gross CONE of a combined cycle plant closer to $168/kW-year, or about $14/kW-month. This new information would not materially impact the *quantity* of new entry in our capacity market analysis, but it would increase the long-term average capacity *price* projections by about $2/kW-month. In light of this new information, we have adjusted the 2014 IRP's capacity price projections to reflect a higher gross CONE value, as described further in sections below.

Figure 11
New Gas CC and CT Costs

		Combined Cycle	Combustion Turbine
Total Plant Capital Cost	*($M)*	$824	$299
Installed Capacity	*(MW)*	730	192
Overnight Cost	*($/kW)*	$1,041	$1,487
Fixed O&M	*($/kW-y)*	$26	$30
After-Tax WACC	*(%)*	7.2%	7.2%
Levelized Gross CONE	***($/kW-y)***	**$142**	**$182**

Note: Resulting capacity prices have been adjusted upwards by about $2/kW-year to reflect higher updated gross CONE estimates, as described in the text of this appendix.

Figure 12
New Gas CC and CT Plant Characteristics

Unit Specifications	Combined Cycle	Combustion Turbine
Turbine Model	Siemens SGT6-5000F(5)	GE LMS100 PA
Primary Fuel	Natural Gas	Natural Gas
Configuration	2 x 2 x 1	2 x 0
Net Plant Capacity (MW)	730	192
without Duct Firing (MW)	631	---
Cooling System	Dry	Dry
Power Augmentation	Evaporative Cooling No inlet chillers	Evaporative Cooling No inlet chillers
Net Heat Rate (Btu/kWh,HHV)	7,526	9,244
without Duct Firing (Btu/kWh, HHV)	7,204	---
Environmental Controls	Dry Low NOx Burners Inlet Air Filters SCR CO Catalyst	Water Injection NOx Control Pulse Inlet Air Filters SCR CO Catalyst
Dual Fuel Capability	ULSD	ULSD
Blackstart Capability	No	No
On-Site Gas Compression	No	Yes
Interconnection	345 kV	345 kV
Plot Size (acres)	20	10
Location	Hampden County, MA	Hampden County, MA

Entry and Exit of Active Demand Response

DR entry and exit are modeled based on the underlying concept that DR penetration levels should increase when capacity prices rise and decrease when capacity prices fall. DR penetration levels are therefore modeled based on a DR supply curve, which is based on estimated DR costs and is calibrated to match the latest FCA7 results.

DR costs include the interruption costs for each call and fixed costs. Interruption costs are based on an expected interruption frequency and a reservation value of $5,000/MWh. The expected interruption frequency is a function of the load duration curve and the amount of other resources available to meet load. DR is interrupted when other resources are insufficient to meet load. The DR supply curve is calibrated to match actual FCA7 results by adjusting the fixed cost parameter. We emphasize that there is substantial uncertainty in our estimate of DR costs.

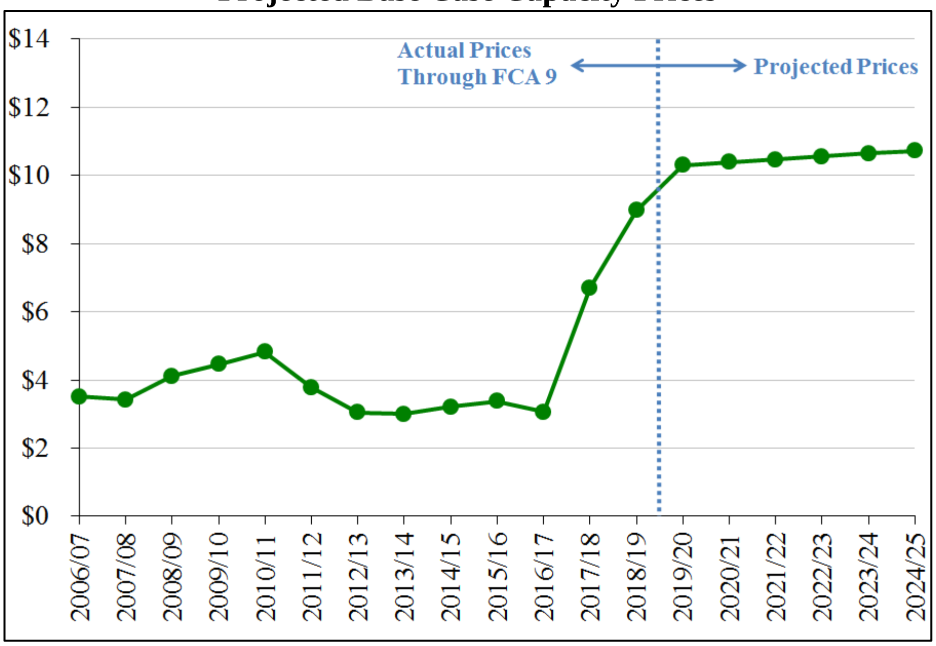
Capacity Market Analysis Results

Figure 13 shows the Base Case capacity price projections at Net CONE from 2019/20 forward, with prices in the prior years reflecting actual auction results (updated through FCA9 for

2018/19). The projection, which was developed before FCA9, does not account for the possibility that excess capacity cleared in FCA9 could depress prices below Net CONE in the following auction or two.

The long-term price projections shown here must be interpreted as unbiased expected average prices needed to support new investment, but not predictions of individual auction outcomes. Individual auction outcomes are sensitive to small changes in supply, demand, and auction parameters. Prices could be higher if new entry is limited, if unexpected retirements occur, imports decline, or NICR values increase; or lower if substantial low-cost capacity enters, imports increase, or NICR decreases. Some of these possibilities are analyzed in the following section addressing alternative Market Scenarios, including one with “Tight Supply” conditions and another with “Abundant Supply” conditions. But year-to-year fluctuations can be even greater than the scenarios might indicate.

Figure 13
Projected Base Case Capacity Prices



Note: Pro-rated historical clearing prices are shown.

Figure 14
Summary of Resources Projected Based on Economics (Base Case)
(Analysis performed prior to FCA8)

		2017 *FCA8*	2018 *FCA9*	2019 *FCA10*	2020 *FCA11*	2021 *FCA12*	2022 *FCA13*	2023 *FCA14*	2024 *FCA15*
ISO-NE									
Projected Economic Retirements	*(MW)*	(95)	(95)	(95)	(95)	(95)	(95)	(95)	(95)
Projected Change in Active DR	*(MW)*	86	136	356	471	560	566	651	707
Projected Economic New Generation	*(MW)*	0	0	0	40	159	340	584	862
Connecticut									
Projected Economic Retirements	*(MW)*	0	0	0	0	0	0	0	0
Projected Change in Active DR	*(MW)*	22	35	93	123	146	147	169	184

BASE CASE RESOURCE ADEQUACY OUTLOOK

Figure 15 and Figure 16 below show the resulting supply-demand balances for Connecticut and ISO-NE, respectively. The bottom line results of the core resource adequacy assessment are highlighted in blue in row thirteen of the Connecticut supply-demand balance and row seventeen of the ISO-NE supply-demand balance. Connecticut is expected to have a surplus of more than 1,800 MW from 2017 until the end of the study period. Region-wide, new generation is needed by 2020 and nearly 900 MW of new generation is needed by the end of the study period. Given the 200 MW less total supply actually cleared in FCA8, we believe the need for new generation in the system could be as early as 2018 in the Base Case. For Connecticut, however, actual FCA8 results do not materially change the projections of supply and demand for the state. Actual supply cleared in Connecticut in FCA8 was 9,191 MW, versus 9,116 MW shown in Figure 15 (the results of FCA9 are not accounted for here). The uncertainty surrounding projections of system-wide supply is analyzed more comprehensively in the following section addressing alternative Market Scenarios.

The following tables do not account for FCA8 and FCA9 results. The IRP Main Report discusses the positive implications of FCA9 for reliability in Connecticut and New England as whole.

Figure 15
Base Case Resource Adequacy Outlook under Connecticut TSA Requirement (MW)[42]

Year (calendar year corresponding to summer of FCM delivery period)		**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
		FCA6	*FCA7*	*FCA8*	*FCA9*	*FCA10*	*FCA11*	*FCA12*	*FCA13*	*FCA14*	*FCA15*
Known and Extrapolated Supply & Demand Factors											
Connecticut Requirement under Transmission Security Analysis	[1]	7,341	7,489	7,273	7,217	7,307	7,383	7,470	7,538	7,609	7,680
CT Sub-Area Internal Installed Capacity as of 5/31/2013	[2]	7,897	7,897	7,897	7,897	7,897	7,897	7,897	7,897	7,897	7,897
Active DR Cleared in FCA6/7, less NPRRs for FCA8, then constant	[3]	474	354	333	333	333	333	333	333	333	333
Passive DR Forecasted by CT EDCs	[4]	475	522	567	609	649	687	723	758	791	822
Existing Purchases & Sales	[5]	(100)	(100)	(100)	(100)	(100)	(100)	(100)	(100)	(100)	(100)
Inclusion of Lake Road Units in CT	[6]	0	0	745	745	745	745	745	745	745	745
Planned Generation Retirements	[7]	(342)	(342)	(348)	(348)	(348)	(348)	(348)	(348)	(348)	(348)
Projected Onshore Wind Additions	[8]	0	0	0	1	1	1	1	1	1	1
Resources Available to Meet CT TSA Requirement	[9]	8,404	8,331	9,094	9,136	9,177	9,215	9,251	9,286	9,318	9,350
Net Subtotal	**[10]**	**1,063**	**842**	**1,821**	**1,919**	**1,870**	**1,832**	**1,781**	**1,748**	**1,710**	**1,670**
Projected Supply Variables											
Projected Active DR Changes as Capacity Prices Change	[11]	0	0	22	35	93	123	146	147	169	184
Projected Economic Retirements	[12]	0	0	0	0	0	0	0	0	0	0
CT Surplus (Shortfall)	**[13]**	**1,063**	**842**	**1,843**	**1,955**	**1,962**	**1,954**	**1,927**	**1,895**	**1,879**	**1,854**
Informational Additional Factors											
Renewable Resources without CSOs	[14]	35	42	45	47	50	51	51	52	52	53
Onshore Wind		1	1	1	0	0	0	0	0	0	0
Offshore Wind		0	0	0	0	0	0	0	0	0	0
Biomass		30	30	30	30	30	30	30	30	30	30
Small Hydro		0	0	0	0	0	0	0	0	0	0
Landfill Gas		0	0	0	0	0	0	0	0	0	0
Grid-Connected Solar PV		4	12	14	17	20	21	21	22	22	23
Potential Reduction in TSA from Distributed Solar and Fuel Cells	[15]	0	0	0	218	250	255	260	266	271	277
Connecticut Requirement under Transmission Security Analysis					6,999	7,057	7,128	7,209	7,272	7,338	7,403
Reduction in peak load from distributed solar and fuel cells in CT					201	231	235	240	245	250	256
CT Surplus, Including Resources w/o CSOs and Reduction in TSA	[16]	1,098	884	1,888	2,220	2,262	2,260	2,239	2,212	2,202	2,183

Sources and Notes:

[1] 2015: 2015/16 1st Annual Reconfiguation Auction.
2016: 2016/17 FCA7.
2017: 2017/18 FCA8.
2018-2024: Calculated based on the methodology listed on page 9 of the ICR and related values for FCA 7 presentation.
[2] 2013 CELT Expected Summer Peak SCC, August 1, 2013.
[3] FCA 6/7 auction results, less DR resources that cleared in FCA7 and submitted NPRRs for FCA8, then constant.
[4] CT EE forecasted by CT EDCs.
[5] FCA7 Auction results, J. Cockwell 1 100MW administrative delist bid.
Reflects the LIPA contract for 100 MW capacity over the Cross Sound Cable through 2021. Assumed in place through 2024.
[6] The completion of the 345 kV Lake Road-Card line will bring these units electrically into Connecticut in 2017.
[7] Norwalk Harbor, John Street 3-5.
[8] Capacity value of projected onshore wind additions in CT as developed in the renewables appendix.
[9] Sum of [2] to [8].
[10] [9] - [1].
[11] Projected economic changes in Active DR, developed in the resources adequacy appendix.
[12] Projected economic retirements, developed in the resource adequacy appendix.
[13] Sum of [10] to [12].
[14] Capacity value of projected offshore wind, biomass, fuel cells, and solar resources without CSOs. Includes capacity value of onshore wind prior to FCA9.
[15] Potential reduction in the CT TSA from net-metered solar and fuel cells, due to reduction in peak load.
[16] Sum of [13] to [15].

[42] Analysis performed prior to FCA8 and FCA9.

Figure 16
Base Case Resource Adequacy under ISO-NE Net Installed Capacity Requirement (MW)[43]

Year (calendar year corresponding to summer of FCM delivery period)		**2015** *FCA6*	**2016** *FCA7*	**2017** *FCA8*	**2018** *FCA9*	**2019** *FCA10*	**2020** *FCA11*	**2021** *FCA12*	**2022** *FCA13*	**2023** *FCA14*	**2024** *FCA15*
Known and Extrapolated Supply & Demand Factors											
ISO-NE 50/50 Gross Peak Load	[1]	28,825	29,350	29,790	30,155	30,525	30,860	31,205	31,520	31,838	32,160
Pool Reserve	[2]	13.7%	12.3%	13.6%	13.6%	13.6%	13.6%	13.6%	13.6%	13.6%	13.6%
Net ICR	**[3]**	**32,771**	**32,968**	**33,855**	**34,270**	**34,690**	**35,071**	**35,463**	**35,821**	**36,183**	**36,548**
Internal Installed Generating Capacity as of 5/31/2013	[4]	31,759	31,759	31,759	31,759	31,759	31,759	31,759	31,759	31,759	31,759
Active DR Cleared in FCA6/7, less NPRRs for FCA8, then constant	[5]	1,985	1,117	904	904	904	904	904	904	904	904
Passive DR Forecasted in 2013 CELT and by CT EDCs	[6]	1,645	1,740	1,973	2,193	2,399	2,593	2,777	2,949	2,982	3,013
Existing Purchases & Sales per ISO-NE in FCA6/7, then constant	[7]	1,824	1,730	1,730	1,730	1,730	1,730	1,730	1,730	1,730	1,730
Planned Generation Retirements	[8]	(1,539)	(1,608)	(3,160)	(3,160)	(3,160)	(3,160)	(3,160)	(3,160)	(3,160)	(3,160)
Mothballed Generation Units	[9]	(40)	(181)	0	0	0	0	0	0	0	0
Planned Non-Renewable Generation Additions	[10]	0	722	722	722	722	722	722	722	722	722
Onshore Wind Additions	[11]	0	0	0	107	107	107	107	107	107	107
Total Resources Available to Meet Net ICR	[12]	35,634	35,279	33,928	34,255	34,461	34,655	34,839	35,011	35,044	35,075
Net Subtotal	**[13]**	**2,863**	**2,311**	**73**	**(15)**	**(230)**	**(416)**	**(624)**	**(810)**	**(1,139)**	**(1,473)**
Projected Supply Variables											
Projected Active DR Changes as Capacity Prices Change	[14]	0	0	86	136	356	471	560	566	651	707
Projected Economic Retirements	[15]	(95)	(95)	(95)	(95)	(95)	(95)	(95)	(95)	(95)	(95)
Projected Economic New Generation	[16]	0	0	0	0	0	40	159	340	584	862
ISO-NE Surplus (shortfall)	**[17]**	**2,768**	**2,215**	**63**	**26**	**31**	**0**	**0**	**0**	**0**	**0**
Informational Additional Factors											
Renewable Resources without CSOs	[18]	158	287	341	248	257	263	264	265	265	266
Potential Reduction in NICR from Distributed Solar and Fuel Cells	[19]	0	0	0	594	691	763	774	781	787	793
ISO-NE Surplus, Including Resources w/o CSOs and Reduction in NICR	[20]	2,926	2,502	404	868	979	1,027	1,039	1,046	1,052	1,059

Sources and Notes:

[1] 2013 CELT 50/50 base economic growth peak load forecast through 2022 then extrapolated at the 2021-22 growth rate.
[2] ([3]-[1])/[1]
[3] 2015: 2015/16 1st Annual Reconfiguation Auction.
2016: 2016/17 FCA7.
2017: 2017/18 FCA8.
2018-2024: Calculated based on 13.6% reserves in the 2017/18 FCA8 ICR.
[4] 2013 CELT Expected Summer Peak SCC, August 1, 2013.
[5] FCA 6/7 auction results, less DR resources that cleared in FCA7 and submitted NPRRs for FCA8, then constant.
Includes 600 MW of RTEG in 2015, and 262 MW of RTEG in 2016 and beyond.
[6] Passive DR forecasted in 2013 CELT and incremental CT EE forecasted by CT EDCs.
[7] FCA 6/7 auction results, then assumed constant (cleared imports net of J. Cockwell 1 100MW administrative delist bid).
[8] Brayton Pt, VT Yankee, Salem Harbor 3 & 4, Norwalk Harbor, Stony Brook (derates), Lowell Cogen, Kendal Steam (derates), MERC, Medway Diesels, John St, Bar Harbor Diesels.
[9] Units with dynamic delist bids in FCA 6-7 that have not annouced retirement: Mt Tom, Covanta West Enfield, Covanta Jonesboro.
[10] Footprint Combined Cycle (674 MW cleared in FCA7), and Northfield Mountain Uprate (48 MW uprate cleared in FCA7).
[11] Capacity value of projected onshore wind additions developed in the renewables appendix.
[12] Sum of [4] to [11].
[13] [12]-[3].
[14] Projected economic changes in Active DR, developed in the resources adequacy appendix.
[15] Projected economic retirements, developed in the resource adequacy appendix.
Includes Schiller 4 & 6, but unit-specific predictions should be considered very uncertain, as described in footnote 36.
[16] Projected economic new generation, developed in the resource adequacy appendix.
[17] Sum of [13] to [16].
[18] Capacity value of projected offshore wind, biomass, fuel cells, and solar resources without CSOs. Includes capacity value of onshore wind prior to FCA9.
[19] Potential reduction in NICR from net-metered solar and fuel cells, due to reduction in peak load.
[20] Sum of [17] to [19].

[43] Analysis performed prior to FCA8 and FCA9.

RESOURCE ADEQUACY IN ALTERNATIVE MARKET SCENARIOS

Four alternative market scenarios were analyzed to reflect uncertainty in natural gas prices and key external supply and demand factors. The four market scenarios are Tight Supply, Abundant Supply, High Gas, and Low Gas. The assumptions underlying each case are described in the IRP report.

Figure 17 shows projected capacity prices across the four alternative market scenarios as well as in the Base Case.

- **Tight Supply Scenario:** Projected capacity prices in this scenario are about $2/kW-month higher than in the Base Case, on average from FCA9 to the end of the study period. High economic growth is assumed, which drives the installed capacity requirement in 2018 (FCA9) to approximately 1,100 MW higher than in the Base Case, and it is assumed that 800 MW of existing capacity is lost due to external factors.[44] As a result, new generation is needed and prices are set at the net Cost of New Entry starting in 2018. Furthermore, it is assumed that CONE in this scenario is 15% higher than our base estimate, reflecting a potentially high-end cost of capital for a merchant developer. This drives capacity prices higher once new entry is needed.

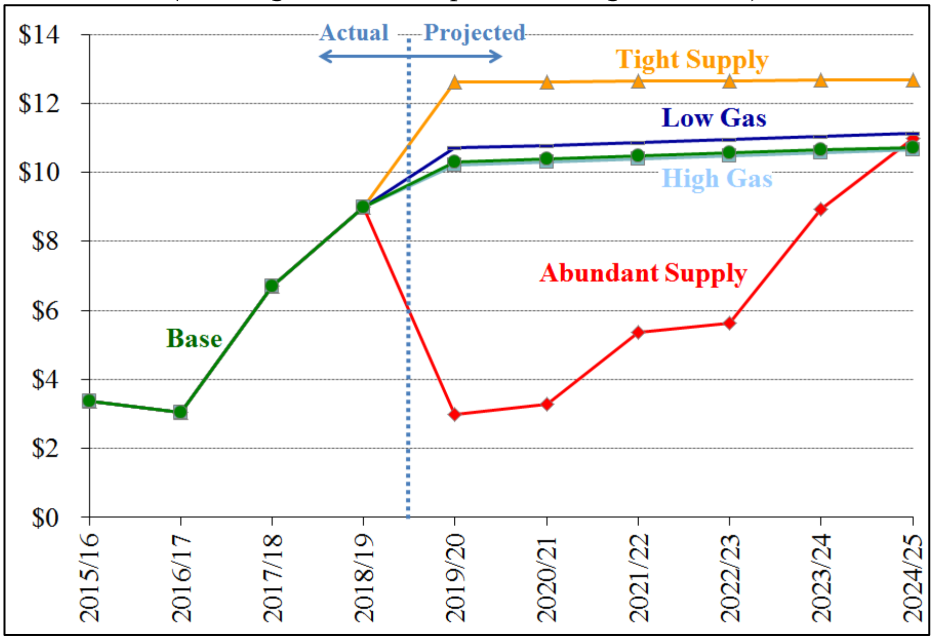
  The high prices projected in this scenario highlight that a modest tightening of supply and demand factors and an increase in CONE would have a pronounced effect on capacity prices.

- **Abundant Supply Scenario:** Projected capacity prices in this scenario are $5/kW-month lower than in the Base Case, on average from FCA9 to the end of the study period. Low economic growth is assumed, which drives the installed capacity requirement in 2018 (FCA9) to approximately 1,100 MW lower than in the Base Case. This reduction in the NICR would likely create a capacity surplus which would result in low capacity prices. Such a reduction in the load forecast and corresponding ICR could be caused by an economic recession, and any capacity surplus created by lower load could persist for many years due to the slow net load growth described in prior sections of this appendix.

- **High and Low Gas Scenarios:** Changes to gas prices have a more modest impact on our capacity price projections than changes in supply and demand factors. New generation is needed in 2018 in both the High and Low Gas scenarios, which is the same year that new generation is needed in the Base Case. Projected energy margins for gas-fired combined cycle units are slightly lower in the Low Gas case, which results in a higher net CONE. Capacity prices are therefore slightly higher than in the Base Case after new generation is needed.

[44] The changes in load in the Tight and Abundant Supply scenarios do not affect the FCA8 ICR or clearing prices because the ICR for FCA8 has already been set and will not be affected by future changes in the load forecast. We recognize, however, that the ICR in the Annual Reconfiguration Auctions could be revised, which could drive changes in the physical supply-demand balance.

Figure 17
Projected Capacity Prices across Alternative Market Scenarios
(showing actual FCA prices through 2018/19)



The following four figures show the components of supply and demand which vary across the alternative market scenarios, as well as the bottom line results of our resource adequacy assessments for both Connecticut and ISO-NE. In all market scenarios, Connecticut is projected to have sufficient capacity to meet its local resource adequacy requirement through the end of the study period, with a surplus of 1,375 to 2,097 MW in 2024. Region-wide, new generation is needed as early as 2018 in the Tight Supply scenario and as late as 2024 in the Abundant Supply scenario, as discussed in more detail above. Given the 200 MW less total supply actually cleared in FCA8, new generation could be economic as early as 2018 in the Base Case, Low Gas Price scenario, and High Gas Price scenarios. For Connecticut, however, actual FCA8 results do not materially change the projections of supply and demand for the state.

Figure 18
Resource Adequacy in Alternative Market Scenarios under Connecticut TSA Requirement[45]

Year (calendar year corresponding to summer of FCM delivery period)	**2015** *FCA6*	**2016** *FCA7*	**2017** *FCA8*	**2018** *FCA9*	**2019** *FCA10*	**2020** *FCA11*	**2021** *FCA12*	**2022** *FCA13*	**2023** *FCA14*	**2024** *FCA15*
Connecticut Requirement under Transmission Security Analysis	7,341	7,489	7,273	7,217	7,307	7,383	7,470	7,538	7,609	7,680
Projected Active DR Changes as Capacity Prices Change	0	0	22	35	93	123	146	147	169	184
Projected Economic Retirements	0	0	0	0	0	0	0	0	0	0
Base Case CT Surplus	**1,063**	**842**	**1,843**	**1,955**	**1,962**	**1,954**	**1,927**	**1,895**	**1,879**	**1,854**
TIGHT SUPPLY										
Connecticut Requirement under Transmission Security Analysis	7,341	7,489	7,273	7,411	7,508	7,602	7,704	7,786	7,868	7,950
Tight Supply Scenario Assumed Loss of Capacity	0	0	0	(286)	(286)	(286)	(286)	(286)	(286)	(286)
Projected Active DR Changes as Capacity Prices Change	0	0	22	170	184	212	215	235	255	261
Projected Economic Retirements	0	0	0	0	0	0	0	0	0	0
Resulting CT Surplus	**1,063**	**842**	**1,843**	**1,609**	**1,567**	**1,539**	**1,476**	**1,449**	**1,420**	**1,375**
ABUNDANT SUPPLY										
Connecticut Requirement under Transmission Security Analysis	7,341	7,489	7,273	7,022	7,090	7,149	7,225	7,277	7,335	7,390
Projected Active DR Changes as Capacity Prices Change	0	0	22	(66)	(47)	(17)	18	30	101	137
Projected Economic Retirements	0	0	0	0	0	0	0	0	0	0
Resulting CT Surplus	**1,063**	**842**	**1,843**	**2,049**	**2,040**	**2,049**	**2,044**	**2,039**	**2,084**	**2,097**
HIGH GAS										
Connecticut Requirement under Transmission Security Analysis	7,341	7,489	7,273	7,217	7,307	7,383	7,468	7,538	7,609	7,679
Projected Active DR Changes as Capacity Prices Change	0	0	22	35	93	123	124	147	169	173
Projected Economic Retirements	0	0	0	0	0	0	0	0	0	0
Resulting CT Surplus	**1,063**	**842**	**1,843**	**1,955**	**1,962**	**1,954**	**1,908**	**1,895**	**1,879**	**1,843**
LOW GAS										
Connecticut Requirement under Transmission Security Analysis	7,341	7,489	7,273	7,217	7,307	7,385	7,470	7,540	7,610	7,680
Projected Active DR Changes as Capacity Prices Change	0	0	22	35	93	144	146	166	180	184
Projected Economic Retirements	0	0	0	0	0	0	0	0	0	0
Resulting CT Surplus	**1,063**	**842**	**1,843**	**1,955**	**1,962**	**1,974**	**1,927**	**1,912**	**1,889**	**1,854**

[45] Analysis performed prior to FCA8 and FCA9.

Figure 19
Resource Adequacy in Alternative Market Scenarios under Connecticut TSA Requirement[46]
Differences Relative to the Base Case

Year (calendar year corresponding to summer of FCM delivery period)		**2015** *FCA6*	**2016** *FCA7*	**2017** *FCA8*	**2018** *FCA9*	**2019** *FCA10*	**2020** *FCA11*	**2021** *FCA12*	**2022** *FCA13*	**2023** *FCA14*	**2024** *FCA15*
Base Case Values, For Reference											
Connecticut Requirement under Transmission Security Analysis		7,341	7,489	7,273	7,217	7,307	7,383	7,470	7,538	7,609	7,680
Projected Active DR Changes as Capacity Prices Change		0	0	22	35	93	123	146	147	169	184
Projected Economic Retirements		0	0	0	0	0	0	0	0	0	0
Base Case CT Surplus		**1,063**	**842**	**1,843**	**1,955**	**1,962**	**1,954**	**1,927**	**1,895**	**1,879**	**1,854**
Differences in Alternate Market Scenarios Relative to the Base Case											
TIGHT SUPPLY											
Connecticut Requirement under Transmission Security Analysis	*[1]*	0	0	0	194	202	219	234	248	259	270
Tight Supply Scenario Assumed Loss of Capacity	*[2]*	0	0	0	286	286	286	286	286	286	286
Projected Active DR Changes as Capacity Prices Change	*[3]*	0	0	0	135	92	89	69	88	86	77
Projected Economic Retirements	*[4]*	0	0	0	0	0	0	0	0	0	0
Resulting CT Surplus *(-[1] -[2] +[3] -[4])*		0	0	0	(345)	(396)	(416)	(451)	(446)	(459)	(479)
ABUNDANT SUPPLY											
Connecticut Requirement under Transmission Security Analysis	*[1]*	0	0	0	(196)	(217)	(234)	(245)	(261)	(274)	(290)
Projected Active DR Changes as Capacity Prices Change	*[2]*	0	0	0	(101)	(139)	(139)	(128)	(117)	(69)	(46)
Projected Economic Retirements	*[3]*	0	0	0	0	0	0	0	0	0	0
Resulting CT Surplus *(-[1] +[2] -[3])*		0	0	0	94	77	95	117	144	206	244
HIGH GAS											
Connecticut Requirement under Transmission Security Analysis	*[1]*	0	0	0	0	0	0	(2)	0	0	(1)
Projected Active DR Changes as Capacity Prices Change	*[2]*	0	0	0	0	0	0	(21)	0	0	(11)
Projected Economic Retirements	*[3]*	0	0	0	0	0	0	0	0	0	0
Resulting CT Surplus *(-[1] +[2] -[3])*		0	0	0	0	0	0	(19)	0	0	(10)
LOW GAS											
Connecticut Requirement under Transmission Security Analysis	*[1]*	0	0	0	0	0	2	0	2	1	0
Projected Active DR Changes as Capacity Prices Change	*[2]*	0	0	0	0	0	21	0	19	11	0
Projected Economic Retirements	*[3]*	0	0	0	0	0	0	0	0	0	0
Resulting CT Surplus *(-[1] +[2] -[3])*		0	0	0	0	0	19	0	17	10	0

[46] Analysis performed prior to FCA8 and FCA9.

Figure 20
Resource Adequacy in Alternative Market Scenarios under ISO-NE Net ICR[47]

Year (calendar year corresponding to summer of FCM delivery period)	**2015** *FCA6*	**2016** *FCA7*	**2017** *FCA8*	**2018** *FCA9*	**2019** *FCA10*	**2020** *FCA11*	**2021** *FCA12*	**2022** *FCA13*	**2023** *FCA14*	**2024** *FCA15*
Net ICR	32,771	32,968	33,855	34,270	34,690	35,071	35,463	35,821	36,183	36,548
Projected Active DR Changes as Capacity Prices Change	0	0	86	136	356	471	560	566	651	707
Projected Economic Retirements	(95)	(95)	(95)	(95)	(95)	(95)	(95)	(95)	(95)	(95)
Projected Economic New Generation	0	0	0	0	0	40	159	340	584	862
Base Case ISO-NE Surplus (Shortfall)	**2,768**	**2,215**	**63**	**26**	**31**	**0**	**0**	**0**	**0**	**0**
TIGHT SUPPLY										
Net ICR	32,771	32,968	33,855	35,389	35,901	36,378	36,855	37,310	37,770	38,236
Tight Supply Scenario Assumed Loss of Capacity	0	0	0	(800)	(800)	(800)	(800)	(800)	(800)	(800)
Projected Active DR Changes as Capacity Prices Change	0	0	86	655	709	814	825	904	983	1,003
Projected Economic Retirements	(95)	(95)	(95)	(95)	(95)	(95)	(95)	(95)	(95)	(95)
Projected Economic New Generation	0	0	0	1,375	1,627	1,805	2,086	2,290	2,639	3,054
Resulting ICR Surplus (Shortfall)	**2,768**	**2,215**	**63**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
ABUNDANT SUPPLY										
Net ICR	32,771	32,968	33,855	33,162	33,474	33,764	34,065	34,338	34,613	34,890
Projected Active DR Changes as Capacity Prices Change	0	0	86	(254)	(180)	(65)	70	117	387	529
Projected Economic Retirements	(95)	(95)	(95)	(785)	(785)	(785)	(785)	(785)	(785)	(785)
Projected Economic New Generation	0	0	0	0	0	0	0	0	0	72
Resulting ICR Surplus (Shortfall)	**2,768**	**2,215**	**63**	**53**	**22**	**41**	**58**	**4**	**32**	**0**
HIGH GAS										
Net ICR	32,771	32,968	33,855	34,270	34,690	35,071	35,463	35,821	36,183	36,548
Projected Active DR Changes as Capacity Prices Change	0	0	86	136	356	471	478	566	651	664
Projected Economic Retirements	(95)	(95)	(95)	(95)	(95)	(95)	(95)	(95)	(95)	(95)
Projected Economic New Generation	0	0	0	0	0	40	241	340	584	905
Resulting ICR Surplus (Shortfall)	**2,768**	**2,215**	**63**	**26**	**31**	**0**	**0**	**0**	**0**	**0**
LOW GAS										
Net ICR	32,771	32,968	33,855	34,270	34,690	35,071	35,463	35,821	36,183	36,548
Projected Active DR Changes as Capacity Prices Change	0	0	86	136	356	553	560	638	693	707
Projected Economic Retirements	(95)	(95)	(95)	(95)	(95)	(95)	(95)	(95)	(95)	(95)
Projected Economic New Generation	0	0	0	0	0	0	159	268	541	862
Resulting ICR Surplus (Shortfall)	**2,768**	**2,215**	**63**	**26**	**31**	**42**	**0**	**0**	**0**	**0**

Note: Absent any transmission upgrades, the quantity of capacity located in Maine would likely exceed the maximum capacity limit by the end of the study period in the Abundant Supply Scenario. However, transmission upgrades associated with integrating wind additions located in Maine would likely increase the export capability by enough so that the maximum capacity limit would not bind.

[47] Analysis performed prior to FCA8 and FCA9.

Figure 21
Resource Adequacy in Alternative Market Scenarios under ISO-NE Net ICR[48]
Differences Relative to the Base Case

Year (calendar year corresponding to summer of FCM delivery period)		**2015** *FCA6*	**2016** *FCA7*	**2017** *FCA8*	**2018** *FCA9*	**2019** *FCA10*	**2020** *FCA11*	**2021** *FCA12*	**2022** *FCA13*	**2023** *FCA14*	**2024** *FCA15*
Base Case Values, For Reference											
Net ICR		32,771	32,968	33,855	34,270	34,690	35,071	35,463	35,821	36,183	36,548
Projected Active DR Changes as Capacity Prices Change		0	0	86	136	356	471	560	566	651	707
Projected Economic Retirements		(95)	(95)	(95)	(95)	(95)	(95)	(95)	(95)	(95)	(95)
Projected Economic New Generation		0	0	0	0	0	40	159	340	584	862
Base Case ISO-NE Surplus (Shortfall)		**2,768**	**2,215**	**63**	**26**	**31**	**0**	**0**	**0**	**0**	**0**
Differences in Alternate Market Scenarios Relative to the Base Case											
TIGHT SUPPLY											
Net ICR	*[1]*	0	0	0	1,119	1,210	1,307	1,392	1,489	1,587	1,688
Tight Supply Scenario Assumed Loss of Capacity	*[2]*	0	0	0	800	800	800	800	800	800	800
Projected Active DR Changes as Capacity Prices Change	*[3]*	0	0	0	519	353	342	265	338	332	296
Projected Economic Retirements	*[4]*	0	0	0	0	0	0	0	0	0	0
Projected Economic New Generation	*[5]*	0	0	0	1,375	1,627	1,765	1,927	1,951	2,055	2,191
Resulting ICR Surplus *(-[1] -[2] +[3] -[4] +[5])*		0	0	0	(25)	(31)	0	0	0	0	0
ABUNDANT SUPPLY											
Net ICR	*[1]*	0	0	0	(1,108)	(1,216)	(1,307)	(1,398)	(1,483)	(1,570)	(1,658)
Projected Active DR Changes as Capacity Prices Change	*[2]*	0	0	0	(390)	(536)	(536)	(491)	(449)	(263)	(178)
Projected Economic Retirements	*[3]*	0	0	0	690	690	690	690	690	690	690
Projected Economic New Generation	*[4]*	0	0	0	0	0	(40)	(159)	(340)	(584)	(790)
Resulting ICR Surplus *(-[1] +[2] -[3] +[4])*		0	0	0	28	(10)	41	58	4	32	0
HIGH GAS											
Net ICR	*[1]*	0	0	0	0	0	0	0	0	0	0
Projected Active DR Changes as Capacity Prices Change	*[2]*	0	0	0	0	0	0	(82)	0	0	(43)
Projected Economic Retirements	*[3]*	0	0	0	0	0	0	0	0	0	0
Projected Economic New Generation	*[4]*	0	0	0	0	0	0	82	0	0	43
Resulting ICR Surplus *(-[1] +[2] -[3] +[4])*		0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	(0)
LOW GAS											
Net ICR	*[1]*	0	0	0	0	0	0	0	0	0	0
Projected Active DR Changes as Capacity Prices Change	*[2]*	0	0	0	0	0	82	0	72	43	0
Projected Economic Retirements	*[3]*	0	0	0	0	0	0	0	0	0	0
Projected Economic New Generation	*[4]*	0	0	0	0	0	(40)	0	(72)	(43)	(0)
Resulting ICR Surplus *(-[1] +[2] -[3] +[4])*		0	0	0	(0)	(0)	42	(0)	(0)	(0)	(0)

Note: Absent any transmission upgrades, the quantity of capacity located in Maine would likely exceed the maximum capacity limit by the end of the study period in the Abundant Supply Scenario. However, transmission upgrades associated with integrating wind additions located in Maine would likely increase the export capability by enough so that the maximum capacity limit would not bind.

48 Analysis performed prior to FCA8 and FCA9.

RELIABILITY IMPLICATIONS OF RELIANCE ON NATURAL GAS

New England has become increasingly dependent on natural gas for its electricity supply. Natural gas fires 43% of electric generating capacity and 52% of annual electricity production, including 48% during January and February, when non-electric gas demand is highest.[49] Yet most gas-fired generators in the region do not have firm capacity for natural gas delivery, relying on "as-available" capacity. Gas-fired generators may have difficulty procuring fuel during winter when the pipelines are fully utilized to serve the heating gas demand by the local distribution companies' (LDCs) core customers.[50] If gas-fired generators are unable to procure fuel and the system needs these generators to meet load, generation prices increase and reliability shortfalls could occur.

Reliance on natural gas-fired generation that lacks firm fuel supplies will grow over the next few years with roughly 3,000 MW of non-gas generation retirements. So far Vermont Yankee nuclear (600 MW), Salem Harbor coal/oil (600 MW), Norwalk Harbor oil (300 MW) are expected to retire by 2014, and Brayton Point coal/oil (1,500 MW) is expected to retire by 2017. As non-gas resources retire, reliance on gas-fired generation will increase. If no non-firm gas is available on the coldest days, there is a risk of depleting operating reserves and reliability could be threatened. Risks increase if more non-gas generation retires or if the gas-fired generators with dual-fuel and firm fuel supplies do not maintain their capabilities in the future. ISO-NE has identified this increased reliance on natural gas-fired capacity as one of the top risks facing the New England electric system.[51]

In light of these risks, ISO-NE has established the Winter Reliability Program and future price incentives for generators to firm up their ability to perform. In addition, ISO-NE, the New England States Commission on Electricity (NESCOE), and the Maine PUC have commissioned studies to evaluate gas-electric adequacy in the region. The New England governors have also proposed an initiative to cooperate on infrastructure development. The sub-sections below summarize these studies and initiatives and their implications for Connecticut.

Six State Initiative

New England's six governors announced a joint effort in December 2013 to address the region's energy challenges. By making strategic investments in regional energy infrastructure, they will improve New England's energy reliability and resiliency, diversify the region's energy portfolio,

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49 Generating capacity based on primary fuel type for existing capacity included in the 2013 CELT generator list (August 1 2013 Expected Summer SCC). Electric production based on 2012 data from ISO-NE (http://www.iso-ne.com/markets/hstdata/rpts/daily_gen_fuel_type/2012_daygenbyfuel.xlsx).

50 New England's gas pipeline system is used primarily to supply natural gas to the core residential and commercial customers of the gas local distribution companies (LDCs). The LDCs have long-term firm contracts with the interstate pipelines that give them the highest possible guarantee of delivery. This guarantee is generally not subject to interruption except in cases of pipeline maintenance or in the event of Force Majeure.

51 Gordon van Welie to NEPOOL Participants Committee New England Conference of Public Utilities Commissioners, September 1, 2011, http://www.iso-ne.com/committees/comm_wkgrps/strategic_planning_discussion/materials/spd_memo_npc_9_2011.pdf.

increase its economic competitiveness by reducing energy costs, and protect New England's environment and quality of life.

The six states, working through the New England State's Committee on Electricity (NESCOE), developed a conceptual proposal called the Governor's Infrastructure Initiative to advance these goals. New natural gas pipelines and electric transmission lines will increase New England's renewable and cleaner-burning energy capacity, assuring a more reliable, diverse and affordable supply of energy.

In light of this, ISO-NE and the New England States Commission on Electricity (NESCOE) commissioned studies which evaluated gas-electric adequacy in the region. In addition, ISO-NE has already implemented and is considering several measures to mitigate the risk of reliability shortfalls due to inadequate fuel.

The sections below summarize the findings (and limitations) of these two New England gas-electric studies, describes ISO-NE's initiatives, and discusses implications and presents recommendations for Connecticut.

Gas-Electric Adequacy Studies

a) ISO-NE Phase I Gas Study (ICF International, 2012)[52]

Since it identified natural gas inadequacy as a key strategic risk, ISO-NE commissioned ICF International (ICF) to evaluate the ability of the gas pipelines to serve the needs of electric generation in New England through 2020. The study evaluated gas adequacy during winter design days[53] when total gas demand is the highest and during summer peak days when the electricity demand is the highest. ICF compared the electric sector gas demand[54] to the total amount of natural gas delivery capacity[55] remaining after serving the firm LDC demand. ICF concluded that the gas pipeline capacity is inadequate to satisfy regional gas demands on a winter design day over the next decade under all cases and scenarios evaluated.[56,57] Figure 22 shows the level of gas infrastructure deficiency identified by the study.

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52 See "Gas Assessment of New England's Natural Gas Pipeline Capacity to Satisfy Short and Near-Term Power Generation Needs." ICF, June 21, 2012 (Public Version). This study is referred to in this document as the "ISO-NE Phase I Gas Study."

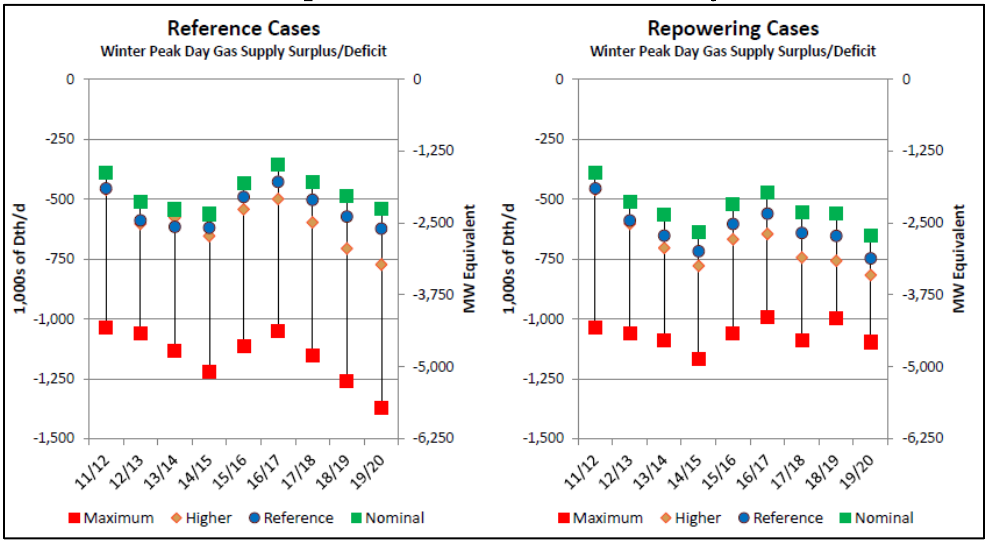
53 Winter design day refers to gas demand based on temperatures corresponding to a particularly cold winter such as 1 in 30 year event.

54 The electric gas demand includes the fuel reserve margin which is defined as "the amount of additional gas required to be continuously delivered (over a 24 hour period) from the triggering of operating reserves in order to replenish the hypothetical loss (N-1) of a 1,200 MW class nuclear unit within the regional fleet." (ISO-NE Phase I Gas Study, p.30).

55 Natural gas delivery capacity included existing interstate pipeline capacity, LNG imports, LNG peak-shaving, and projected 350 MMcf/d expansion of the Algonquin system (Algonquin AIM project) by November 2016.

56 ICF evaluated a Reference Case assuming that existing fleet continues to operate and a Repowering Case assuming some of the non-gas capacity is replaced with gas-fired capacity over time. For each of these cases, ICF evaluated 4 gas demand scenarios: (1) Nominal Gas Demand with 50/50 electric demand; (2) Reference Gas Demand with 90/10 electric demand; (3) Higher Gas Demand assuming additional gas demand to cover a

Figure 22
New England Gas Supply Surplus/Deficit
As per ISO-NE Phase I Gas Study



Source*:* ISO-NE Phase I Gas Study, p.32.

The study has some limitations which were noted.[58] For example, the study evaluated New England as a whole and did not account for any potential intra-regional differences. It did not assess whether gas pipeline and transmission bottlenecks in a particular sub-region might make that sub-region vulnerable even though New England as a whole may have sufficient gas and electric resources. Similarly, the study only assessed gas-electric adequacy on a daily basis during peak winter and summer day while ignoring hourly variations that occur on an intra-day basis in both gas availability and electric load. The ICF study does underscore DEEP's finding that current gas pipeline capacity is inadequate to satisfy regional gas demands on a winter peak design day over the next decade under all cases and scenarios evaluated.

b) NESCOE Phase I, II, and III Gas Study (Black and Veatch, 2013)

The New England States Committee on Electricity (NESCOE) retained Black and Veatch (B&V) to assess the adequacy of the natural gas infrastructure to support power generation and to evaluate potential solutions.

The study was conducted in three phases.

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disruption to non-gas-fired capacity, but higher gas prices moderates gas demand; and (4) Maximum Gas Demand assuming additional gas demand to cover a disruption to non-gas-fired capacity and low gas prices drives more gas demand.

57 The study also found that under the Maximum Gas Demand Scenario the natural gas supply capability during the summer peaks might be inadequate until the natural gas pipeline capacity expansion (Algonquin AIM project) is built in 2015/2016.

58 ISO-NE Phase I Gas Study, p.37.

Phase I (December 2012): reviewed existing studies and literature on this topic and concluded that New England's natural gas infrastructure will become increasingly stressed as regional demand for natural gas grows due to coal plant retirements and summer peak growth (albeit reduced), leading to infrastructure inadequacy at key locations."[59]

Phase II (April 2013): analyzed the extent and duration of historical and forecasted natural gas congestion. Black and Veatch evaluated the adequacy of New England's gas-electric infrastructure and projected constraints lasting more than 30 days across several sub-regions in the near future. They identified constraints by using daily load duration curves for the 14 sub-regions in New England and counting the number of days when the demand is higher than 75% of the current pipeline capacity serving the sub-region. Black & Veatch concluded that with existing natural gas infrastructure, significant portions of New England would experience infrastructure constraints lasting for more than 30 days in the relatively near future.

Phase III (September 2013): Black and Veatch evaluated a combination of two short-term solutions against three long-term solutions that could alleviate constraints on the natural gas pipeline system under the base case and high demand scenarios. Specifically, the net benefits of 1) 2.3 TWh of dual-fuel generation with demand response and 2) an additional 300 MMcf of daily LNG purchases were compared with those of three long-term solutions: 3) a cross-regional, 1.2 Bcf/d natural gas pipeline 4) 1,200 MW of firm-priced Canadian hydropower and 5) 1,200 MW of economic-priced (non-firm) Canadian hydropower under a base case, a high demand scenario, and a low demand scenario. The base case evaluated the most likely outcome based on Black and Veatch's outlooks,[60] the high demand scenario increased gas use, and the low demand scenario analyzed flat or declining gas demand.

The NESCOE study tried to address several shortcomings in the 2011 ISO-NE Phase I Study. In order to account for intra-regional constraints, the study separately analyzed 14 different sub-regions within New England. The NESCOE study also evaluated gas infrastructure adequacy accounting for the hourly variations in gas demand by electric generators.[61]

Black and Veatch concluded that a combination of short –term and long term solutions are needed and cost beneficial to relieve the natural gas market constraints in New England under the Base Case. B&V recommends that dual-fuel generation, demand response measures and the seasonal purchase of LNG cargoes be deployed immediately. Short term strategies can be deployed quickly to provide immediate benefits in alleviating infrastructure constraints over the next few years but are less cost effective than a gas pipeline over the longer term of the full study period.

[59] See "Natural Gas Infrastructure & Electric Generation: A review of issues facing New England," Black and Veatch, April 16, 2013, p.2.

[60] In the base case, Black and Veatch assumed the Algonquin pipeline capacity will be expanded via the AIM project by approximately 500 MMcf/d. See "Natural Gas Infrastructure and Electric Generation: Proposed Solutions for New England," August 26, 2013, p.29.

[61] Black and Veatch concluded that their hourly models do not yield results that were materially different from their daily models. See "Natural Gas Infrastructure and Electric Generation: Constraints and Solutions," Black and Veatch, April 16, 2013, p.20.

A Cross-Regional Natural Gas Pipeline solution presents higher net benefits to New England consumers than do alternative long-term solutions from 2017 to 2029. This pipeline could yield $118 million of annually averaged net benefits as opposed to economic hydropower imports ($37 million), firm hydropower imports ($61 million), LNG imports ($96 million)[62], and dual fuel with demand response ($101 million).

Adding pipeline capacity and firm hydro imports both offer solutions to improve winter reliability and lower electric costs but do so it different ways. The incremental pipeline option makes gas more available so existing gas generators can operate during peak periods. This improves the reliability of gas generators and in doing the reliability of the electric system. Adding gas supply will also drive down gas prices. With lower gas costs generators can reduce their bids in the wholesale energy market and thereby lower wholesale electric prices.

Importing power can also improve reliability and lower cost but does so by displacing gas generation with hydro generation. Hydro has no fuel costs and therefore can bid zero or close to it in the energy market. This compares to gas and oil generators that must bid their fuel costs. Due to its lower variable cost hydro is dispatched sooner than gas and oil generation lowering wholesale energy prices. Reliability is improved by requiring firm delivery in the hydro contract during peak periods when gas may not be available for gas fired generators.

In the wholesale market the last generator selected to meet demand in each hour sets the clearing price for all generation in that hour. If something can be done to reduce the clearing price in a particular hour such as by adding pipeline capacity or adding lower cost hydro generation, the cost of all generation is reduced and therefore can provide significant benefits. This is referred to as "price suppression" and is the primary benefit analyzed in the B&V studies

The gas pipeline is estimated to cost approximately $2.3 billion or $176 million annually over the twelve years from 2017 through 2019. The estimated benefits are $6.7 billion or $516 million annually for a benefit to cost ratio of 2.93.

Firm Canadian electric imports were more cost effective than market based imports. Importing power from Canada was not as cost effective as the pipeline option but still is cost effective and a viable long term solution for the winter reliability issue. In addition, Canadian hydro offers many other possible benefits to meet the long term resource, cost and environmental goals of Connecticut and the region not considered or quantified in the B&GV study.

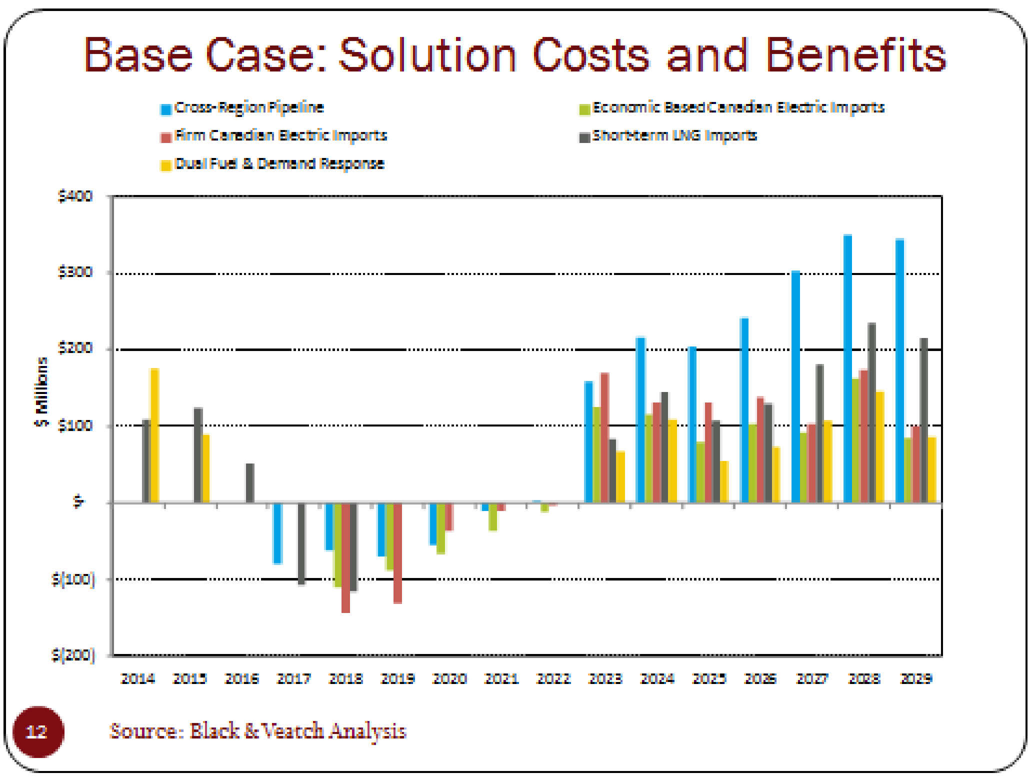
The B&V study evaluated all resource solutions based on their potential wholesale energy price suppression effects. This is a good metric for evaluating the gas pipeline and short-term options since they are the primary benefits associated of those options. However, Canadian hydro offers other benefits not monetized in this analysis.

[62] The LNG Import and Dual Fuel & Demand Response options would be forgone in years of negative net benefits. Therefore, the average net benefit of LNG jumps to $138 million when these years are omitted from the calculations.

B&V included only transmission costs in its analysis of the non-firm hydro option. For the firm option B&V included transmission and generation costs but none of the additional benefits that hydro power can offer. Hydro is cleaner than natural gas or oil. These emission benefits will benefit all customers in New England. Other benefits may include capacity value, capacity price suppression, and energy savings if the price is below the long term market rates. Hydro might also be coupled with Class I resources to help meet RPS goals and reduce REC prices.

B&V estimated the construction cost to of a 180 mile transmission line originating at the Canadian border and terminating in New England to be $1.1 billion. Leveled over twenty years, the annual cost of service for the project was estimated to range from $180 to $219 million. Canada is a winter peaking market which may limit energy imports offered to New England during winter months when gas infrastructure is most constrained. Imports for economic based power therefore were assumed to be limited, never exceeding 700 MWh in the winter throughout the analysis period. This assumption limited the benefits of non-firm imports to $256 million annually and results in $37 million in net benefits over the study period.

For the firm import analysis B&V assumed the expansion and or construction of generating facilities and a firm contract for 1200 MW every hour. This added $170 million in costs annually but also increased price suppression savings by $194 million annually resulting in a net benefit of $61 million. But as mentioned above no other benefits associated with the generation were included in the B&V analysis.



B&V also conducted a High Demand and a Low Demand scenario as a sensitivity to its Base Case analysis.

In the High Demand Scenario, B&V made six alterations from the Base Scenario that would reduce the supply and increase demand for natural gas. B&V reduced its supply by assuming that 1) consumer penetration growth rates would slow down in states with high degrees of penetration; 2) international LNG exports would siphon an additional 4 Bcf of gas per day away from the New England market; and 3) M&NP is allowed to redirect gas flows to Canada when price arbitrage opportunities arise. To increase demand, the High Demand Scenario assumed that states would only achieve 75% of their RPS goals, rather than 100% in the Base Scenario, thereby increasing gas-fired electricity demand. It also assumed that energy efficiency measures would be less prevalent or effective, resulting in a 0.2% annual electricity demand growth rate rather than 0.18% in the Base Scenario. Finally, nuclear plants retire five years earlier in this High Demand Scenario than in the Base Scenario. By 2029, these six calibrations exceeded New England's Base Scenario gas demand by 300 MMcf/d, while the average monthly prices would be higher, by $2-$4/MMBtus, during the winter peak months.

B&V also conducted a "design-day" sensitivity analysis that estimated the impact of an extreme, prolonged cold snap on natural gas demand. Using a climatological dataset extending back to 1983, B&V identified the coldest week-long period as a worst-case weather scenario. Then, to gauge the sensitivity of energy consumption to weather in winter months, B&V compared America's energy consumption patterns with weather data and found the highest correlation from 2008 to 2013. Using this relationship, B&V reconfigured its energy demand forecasts as if January was as cold as the coldest week-long period. Energy demand subsequently rose by 2.56 times the 2004 annual average demand, exceeding all available capacity in 2027.

The savings and therefore benefit cost ratio of each of the long term solutions increased significantly in the High Demand Scenario compared to those in the Base Case. Savings for the gas pipeline increased from $294 million annually to $516 million annually, increasing net benefits to $340 million annually and the benefit cost ratio to 2.93. The benefits also increased for the Firm Hydro import option, more than doubling from $61 million to $123 million annually. This increased the benefit/cost ratio to approximately 1.31 compared to approximately 1.15 for this option in the Base Case. Again, as explained above, the Firm Import option included generation costs but only savings associated with lower wholesale energy prices.", No other benefits associated with a firm fixed price contract were included. The benefits associated with LNG imports also increased in the high demand scenario, but the gas pipeline remained as a better long term solution for winter reliability.

By contrast, B&V observed no constraints in the Low Demand Scenario.[63] The Low Demand Scenario assumptions are much simpler. B&V assumes that natural gas and electricity demands will not grow any further. This could be attributable to higher deployment rates of renewable energy, substantial energy efficiency gains. As a result, New England's natural gas demand is

[63] See "Natural Gas Infrastructure and Electric Generation: Proposed Solutions for New England," August 26, 2013, p.13.

lower than the Base Scenario by 100 Mcf/d in 2014, and 400 Mcf/d by the end of the modeling period in 2029. Monthly average electricity prices were significantly depressed from the Base Scenario by $15-20/MWh. B&V also considered a scenario in which electricity and gas demands would actually decline by 1% under these conditions in 2020 and 2% by 2030. This only reduced New England's gas demand by 50 MMcf/d, a virtually negligible result.

High Natural Gas Demand Solutions

Total Benefits for Infrastructure Solutions (in Millions of Dollars)

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Total	Average
Cross-Region Pipeline	$ -	$ -	$ -	$ 94	$ 113	$ 127	$ 122	$ 79	$ 177	$ 407	$ 687	$ 719	$ 740	$1,050	$1,096	$1,300	$ 6,712	$ 516
LNG Imports	$ 301	$ 349	$ 250	$ 67	$ 69	$ 59	$ 69	$ 121	$ 103	$ 310	$ 589	$ 630	$ 683	$ 849	$ 837	$ 875	$ 6,159	$ 433
Firm Contract Based Canadian Energy Imports	$ -	$ -	$ -	$ -	$ 264	$ 270	$ 333	$ 296	$ 385	$ 621	$ 763	$ 623	$ 557	$ 781	$ 613	$ 634	$ 6,139	$ 512

Total Costs for Infrastructure Solutions (in Millions of Dollars)

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Total	Average
Cross-Region Pipeline	$ -	$ -	$ -	$ 176	$ 176	$ 176	$ 176	$ 176	$ 176	$ 176	$ 176	$ 176	$ 176	$ 176	$ 176	$ 176	$ 2,288	$ 176
LNG Imports	$ 180	$ 174	$ 175	$ 182	$ 184	$ 186	$ 189	$ 191	$ 193	$ 195	$ 197	$ 199	$ 202	$ 204	$ 206	$ 209	$ 3,066	$ 196
Firm Contract Based Canadian Energy Imports	$ -	$ -	$ -	$ -	$ 389	$ 389	$ 389	$ 389	$ 389	$ 389	$ 389	$ 389	$ 389	$ 389	$ 389	$ 389	$ 4,668	$ 389

Net Benefits for Infrastructure Solutions (in Millions of Dollars)

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Total	Average
Cross-Region Pipeline	$ -	$ -	$ -	$ (82)	$ (63)	$ (49)	$ (54)	$ (97)	$ 1	$ 231	$ 511	$ 543	$ 564	$ 874	$ 920	$1,124	$ 4,424	$ 340
LNG Imports	$ 121	$ 175	$ 75	$(115)	$(115)	$ -	$ -	$ -	$ -	$ 115	$ 392	$ 430	$ 482	$ 645	$ 630	$ 666	$ 3,093	$ 236
Firm Contract Based Canadian Energy Imports	$ -	$ -	$ -	$ -	$(125)	$(119)	$ (56)	$ (93)	$ (4)	$ 232	$ 374	$ 234	$ 168	$ 392	$ 224	$ 245	$ 1,471	$ 123

The Black and Veatch Study concluded in early September 2013. As discussed further below, facts have played out that do not align with some of the Study's assumptions.

New England Power System Events Following the Study That Make Infrastructure Constraints More Severe Than Contemplated by the B&V Study:

- **Vermont Yankee**: The Study assumed the Vermont Yankee nuclear station would operate to the end of its current license in 2032. On August 27, 2013, Vermont Yankee announced that it is retiring in 2014. The power plant's approximately 600 MWs of low-carbon, non-gas-fired energy is likely to be replaced by gas-fired resources. This has the potential to increase regional gas demand by 100 mmcf/day above that contemplated by the Study.

- **Brayton Point**: The Study assumed that the Brayton Point coal-and oil-fired generation station would continue to operate through the study period. On January 27, 2014, Brayton Point announced that it will retire in 2017. A portion of the power plant's approximately 1500 MWs of non-gas-fired energy is likely to be replaced by gas-fired resources, increasing regional gas demand beyond that assumed in the Study.

- **The AIM Project**: The Study assumed that Spectra's Algonquin Incremental Market ("AIM") project would be built at 500 mmcf/day. Since the Study concluded, Spectra has announced that the project will now increase natural gas import capability into New England by 342 mmcf/day in 2016. This smaller project size will provide less infrastructure congestion relief, approximately 150 mmcf/day than assumed in the Study.

- **Winter 2013-2014 Experience**: Natural gas daily prices in New England in January and February 2014 exceeded $80/MMBtu, and the average monthly price in January was $22.34/MMBtu. In contrast, the Study forecasted daily prices to be *at worst* on the order of $10/MMBtu in the short-term and $10-$20/MMBtu in the long-term under High Demand conditions and monthly average prices to be *at worst* on the order of $5-8/MMBtu.

It is reasonable to assume that the combined effect of these facts understates the benefits associated with the solutions in the Base Case Study and the severity of future prices associated with infrastructure inadequacy. DEEP and the NESCOE Six State participants believe that the High Demand Scenario better represent the potential savings of the long term solutions going forward based on these most recent events.

Finally, NESCOE asked B&V to conduct an analysis of multiple long term solutions. The previous analysis looked at each resource option separately. B&V modeled the gas pipeline and Firm Contract based Canadian Imports relative to the High Demand scenario.

The Multiple long-term Solutions Scenario generates $780 million a year of price suppression benefits to New England electric and natural gas customers. With an average cost of $395 million annually for both projects the benefit to cost ratio is approximately 2.0 for the multiple long term solutions, when the hydro generation costs are removed. The development of both long term solutions, gas pipeline and Firm Imports, creates additional benefits than just the pipeline option but less than the sum of each project previously calculated on an individual basis. When the combined costs of developing the pipeline and transmission and generation infrastructure is included the net benefit are estimated to be $385 million annually to the regions energy consumers. These annual net benefits are $45 million higher than those estimated for the pipeline alone and $262 million higher than the Import Scenario alone. As explained previously DEEP believes that the high demand Multiple Lon-Term solution Scenario is the most appropriate analysis given the situation as it now exists. This analysis indicates that the two pronged approach of incremental gas pipeline capacity and electric transmission facilities linked to Firm Canadian hydro is a cost effective approach to improving the winter reliability problem and lowering costs to customers in New England. The inclusion of hydro provides additional benefits to meet long term resource needs, provide fuel diversity, and improve emissions.

c) Maine Public Utilities Commission Review of Natural Gas Capacity Options

Sussex Economic Advisors, LLC ("Sussex") was retained by Maine PUC to review the various natural gas pipelines serving New England, their related open seasons for capacity, and the potential costs and benefits of incremental natural gas deliverability into New England. The findings and conclusions in their report, dated February 26, 2014, are consistent with those of NESCOE, ICF, and this IRP.

Similar to other reports, Sussex analysis shows that current prices are high in New England are high and forward prices are expected to continue to be at a premium to Henry Hub and Mid – Atlantic natural gas prices in the future. The current 2013/2014 New England to Henry Hub basis averaged $9.86/MMBtu, is nearly four times higher than the five year historical average of $2.50/MMBtu. The high natural gas premium (basis differential) between New England and Mid-Atlantic states reflects the existing pipeline constraints these regions.

Based on the relationship between natural gas and electric locational marginal prices in ISO-NE, Sussex calculated the potential reduction in LMPs as a result of a reduction in wholesale natural gas prices to estimate the potential energy cost savings to electric customers for the year November 2012 through October 2013. The report concludes that savings associated with a reduction of 40% in New England natural gas basis would offset the cost of a 1,000,000 Dth/day of incremental pipeline capacity, assuming a daily pipeline charge as high as $2.00/Dth.

Conclusion

As a result of the studies conducted, the Six State Initiative has concluded that additional investments in energy infrastructure are needed to address the winter peak reliability issue. Specifically, the proposal calls for one-time solicitations for:

- *Greater natural gas capacity*, incrementally priced and installed by 200 MMcf/day with the goal of installing at least 1 Bcf of new capacity above 2013 levels

- *New electric transmission lines*, obtained through power contracts executed between eligible resources and those states procuring power pursuant to state statutory authority. Following project evaluations, all states would potentially share in the cost of the transmission, while costs related to the power would be borne by contracting states.

Funding mechanisms could be established in the ISO-NE tariff to recover from electric ratepayers, as the beneficiaries of investments, the costs of new pipeline and transmission. Such funding mechanisms, and any associated tariff changes, would be subject to review and approval by the FERC. Costs would be appropriately allocated among the six states consistent with the judgment of each state regarding the benefits of infrastructure investments.

ISO-NE Current and Proposed Gas-Electric Solutions

ISO-NE has already implemented several initiatives and is currently discussing longer-term solutions to address risks identified in the Strategic Planning Initiative associated with unit performance and gas dependency. These initiatives address: “1) filling information gaps with better and timely information to manage the power system; 2) enhancing market mechanics to better enable resource performance; 3) improving market incentives for resources to perform;

and 4) procuring sufficient reserves for reliability."[64] Some of these initiatives are discussed below:

Existing Initiatives

- **Proactive Commitment of Non-Gas Resources:** During periods of gas supply and deliverability constraints, ISO-NE proactively commits long lead-time oil-fired generators out-of-economic-merit so that they are available for dispatch when needed.

- **2013/2014 Winter Reliability Program**: The Winter Reliability Program was an out-of-market solution designed to procure adequate resources necessary to maintain reliability during the winter of 2013/2014. This program helped to maintain reliability this past winter while medium- and long-term solutions are being developed. The program include: (a) incentives for oil-fired generators to increase their fuel oil inventory; (b) a winter demand response program; (c) payments to dual fuel units for testing their fuel-switching capability; and (d) changes to market monitoring to increase generators' flexibility.[65] Through this program, ISO-NE recently procured roughly 1.951 million MWh of demand response and oil inventory service at a cost of $75.1 million and made changes to Market Rules aimed at increasing fuel-switching flexibility.[66]

    - **Oil Inventory Program**: This is by far the largest component of this program, consisting of roughly 1.947 million MWh, or over 99.8% of the procured energy.[67] The oil-fired generators and dual-fuel generators selected are required to be able to switch to run on oil within five hours. The program participants establish an initial fuel inventory in their tanks prior to December 1, 2013, and, in the case of some dual-fuel generators, to replenish their fuel inventory until their total commitment is satisfied. Participants are also required to submit supply offers into the day-ahead and real-time markets for each hour of the operating day at their economic max limits. These resources were compensated through a monthly payment derived from the resources' "as-bid" price, but will be subject to penalties if they fail to perform. [68]

    - **Demand Response**: The ISO used the demand response participating in this program to maintain 30-minute reserves. These DR resources were required to dispatch no more than 10 times during the Program's duration and are required to be available between 5:00 a.m. and 11:00 p.m. They receive a monthly payment

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64 See Interdependencies of Market and Operational Changes to Address Resource Performance and Gas Dependency, ISO-NE, 2013, available at http://www.iso-ne.com/committees/comm_wkgrps/strategic_planning_discussion/materials/interdependency_of_iso_proposals_to_key_spi_risks.pdf.

65 See ISO-NE Transmittal, Docket No. ER 13-2266-000, June 28, 2013, p. 4.

66 See Filing in Compliance with Order Conditionally Accepting Bid Results; Docket No. ER 13-2266-000, October 15, 2013, p.7.

67 See Attachment 2 to Filing in Compliance with Order Conditionally Accepting Bid Results; Docket No. ER 13-2266-000, October 15, 2013.

68 See ISO-NE Transmittal, Docket No. ER 13-2266-000, June 28, 2013, pp. 8-15.

based on their as-bid price as well as energy payments for demand reductions. Failure to perform resulted in a $250/MWh penalty and loss of the entire amount of the monthly payments if the DR resource achieves less than 75 percent of its committed MW quantity for a month.[69]

- **Dual-Fuel Testing**: This program provided compensation for dual-fuel units enrolled in the oil inventory service for a successful test of their switching capability. However, the participants may lose an amount up to their monthly payment if they fail to test its unit successfully by December 15.[70]

- **Market Rule Changes**: Lastly, the program removed a requirement for resources to seek the Internal Market Monitor's approval before switching fuels. These Market Rule changes were intended to increase fuel-switching flexibility.[71]

- **Increased Coordination and Communication with Gas Pipelines**: ISO-NE received approval from the Federal Energy Regulatory Commission (FERC) on an interim basis for winter of 2013/14 to share forecasted schedule and real-time information about specific gas generators with the region's gas pipelines.[72] This measure is intended to enhance reliability by improving communication and coordination between electric and gas control room operators. Communication of operational information between gas industry and transmission operators are currently being explored through FERC's NOPR in Docket No. RM13-17-000.

- **Improved Scheduling**: ISO-NE recently accelerated the deadlines for the Day-Ahead Market (DAM) and Reserve Adequacy Analysis (RAA) effective May 23, 2013. Now, the DAM offer closes at 10:00 a.m. with results posted at1:30 p.m., and the initial RAA process is completed by 5:00 PM. This earlier clearing of the DAM and RAA will provide ISO-NE more time for ISO to commit long lead-time resources if necessary. The earlier bidding window and RAA will improve gas-fired generation's ability procure fuel, for example by providing them access to the most liquid gas trading period in the day. [73]

- **Allow Hourly Re-Offers**: In an Order issued on October 3, 2013 FERC conditionally approved ISO-NE's proposed market rules to allow participants to update their offers in real-time to reflect changing fuel costs. These changes will allow participants to better reflect actual fuel or other operational costs, improving market pricing and incentives to perform.[74]

<u>Initiatives in Place for the Future</u>

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[69] *Id*., pp. 15-17.
[70] *Id*., pp. 17-18.
[71] *Id*., pp. 18-22.
[72] While FERC approved the proposal in interim, it noted that the changes "may be unjust, unreasonable, unduly discriminatory or preferential, or otherwise unlawful." See 141 FERC ¶ 61,196, p.11.
[73] See ISO-NE's Settlements Issues Forum, Q2 2013 Meeting, Rachel Likover, June 28, 2013, slides 14-15, available at http://www.iso-ne.com/stlmnts/qrtly_stlmnts_mtrls/settlement_quarterly_webex_06_12_2013.pdf.
[74] See 145 FERC ¶ 61,014.

- **2014/15 Winter Reliability Program:** ISO-NE continued the program for Winter 2014/15 that included liquefied natural gas (LNG) inventories in addition to oil. ISO-NE also instituted stronger scarcity price signals in its energy market (starting in 2014) and Performance Incentives tied to its capacity market (starting in 2018). These signals will help incent generators to maintain sufficient fuel inventory to be able to perform during shortage events. However, reliably meeting winter demand will likely become increasing challenging as non-gas retirements make the region increasingly dependent on natural gas-fired generation that lacks firm transportation rights. It is not yet clear whether ISO-NE's price signals will be strong enough to fully align behavior with the region's reliability objectives

- **Strengthen Forward Capacity Market**: In the long-term, ISO-NE is strengthening the Forward Capacity Market (FCM) with performance incentives to address the risk of gas dependence. "FCM Pay for Performance" proposal will expose resources to stricter penalties for non-performance to incentivize them to invest in capabilities that enable them to always perform.[75] It is yet to be seen, but these performance incentives may introduce substantial and difficult-to-quantify risks that could deter entry (especially of active demand resources) while inducing existing resources to retire.

Implications for the State of Connecticut

The studies described above conclude that the natural gas infrastructure is inadequate to serve the needs of the region's gas-fired generation and therefore poses a threat to electric reliability. DEEP will work with other New England States, ISO-NE and stakeholders to develop a plan to implement the least-cost solution with minimal market distortions. DEEP will also continue to participate in ISO-NE stakeholder committees to ensure the development of effective and least-cost solutions. Lastly, DEEP will monitor and learn from measures other states in the region are undertaking to mitigate risks posed by gas reliance.

[75] See Interdependencies of Market and Operational Changes to Address Resource Performance and Gas Dependency, ISO-NE, 2013.