Docket No. ______
Exh. TDI-SGP-9

Seth G. Parker Direct Testimony on the New England Clean Power Link on behalf of Champlain VT, LLC

Exhibit 9. Technical Report

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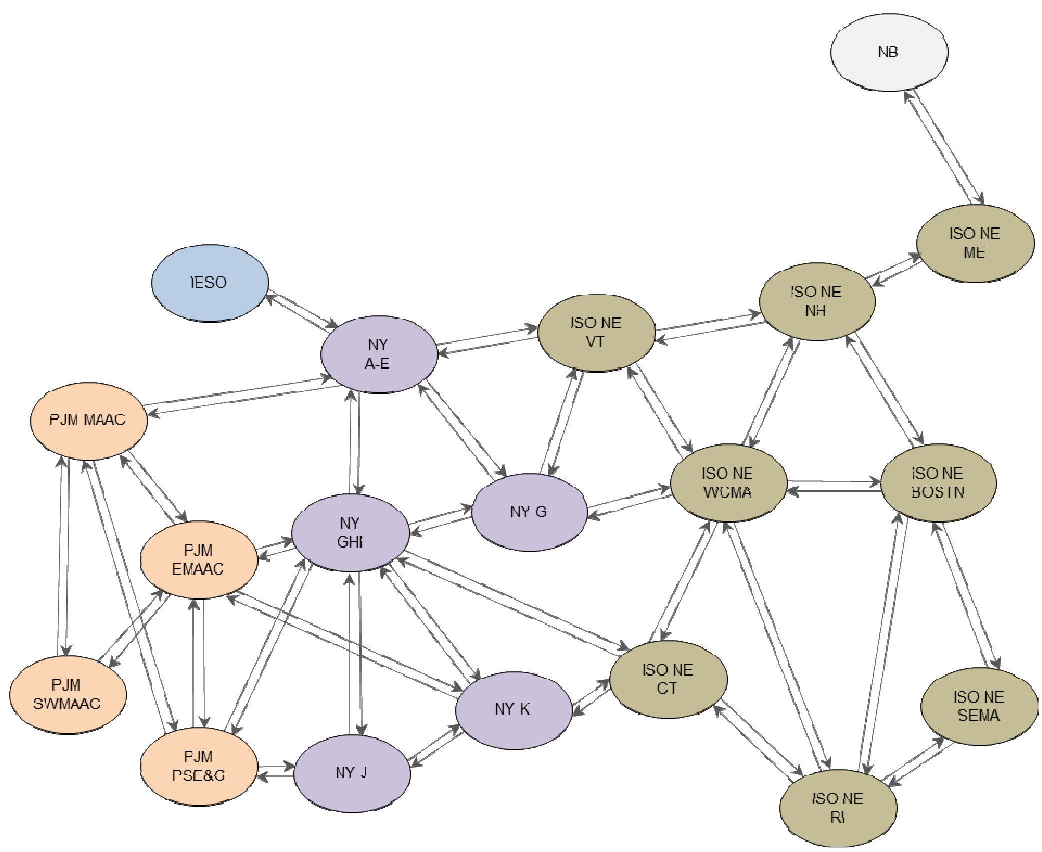
1 INTRODUCTION

This Technical Report summarizes the key underlying assumptions that Mr. Parker used to forecast the estimated power market and air emission impacts to the State of Vermont and to New England in general due to the New England Clean Power Link ("NECPL").

2 ENERGY PRICE FORECAST

We prepared the long-term forecast of ISO-NE wholesale energy prices using the AURORAxmp multi-area chronological dispatch simulation model on a zonal basis. We divided ISO-NE into eight zones using transfer limits that occasionally result in congestion and energy price separation. In addition to ISO-NE, our dispatch simulation modeling included NYISO (divided into five zones), the MAAC portion of PJM (divided into four zones), Ontario, and New Brunswick, plus scheduled imports / exports between Quebec and ISO-NE and NYISO based on historical energy flows.

Figure 1. AURORAxmp Topology



2.1 Transmission Interface Capability Values

The transmission interface limits that define energy flows between the AURORAxmp topology zones depend on a number of variables, including load levels / distribution, generation availability, generation source / sink combinations, transmission facility outage assumptions, transmission facility ratings, and phase angle regulator settings. These limits are normally determined using a load flow model and are normally assumed constant for a given period of time. LAI relied on latest available information published by each ISO / RTO, as indicated in Table 1. The ISO-NE transmission interface limits include the New England East-West Solution ("NEWS") project.

Table 1. ISO / RTO Transmission Interface Limit Sources

ISO-NE	2013 Regional System Plan
NYISO	2014 Resource Needs Assessment Report
PJM (MAAC)	2017-18 RPM BRA Planning Period Parameters Report

2.2 Load Forecast Data

LAI utilized the load shape data in the AURORAxmp database and updated the load forecasts based on the ISO / RTO sources listed in Table 2.

Table 2. ISO / RTO Load Data Sources

ISO-NE	2013 Regional System Plan
NYISO	2014 Load and Capacity Data Report
PJM (MAAC)	2014 Load Forecast Report

2.3 Renewable Resource Additions

The majority of New England states have Renewable Portfolio Standard ("RPS") requirements or similar programs that support the development of renewable resources. LAI's modeling incorporated the expected buildout of renewable resources, which generally lags the RPS requirements. LAI assumed that most of the renewables energy expansion will consist of onshore wind, with some solar photovoltaic ("PV") and offshore wind in the ISO-NE, NYISO and PJM markets. We assumed that onshore wind expansion would be a function of the relative wind resource potential in each zone, and implicitly assumed that transmission will be built to interconnect those resources to the grid. All the renewable energy projects in the interconnection queues that have been fully permitted were included, *e.g.* the Cape Wind and the Block Island Offshore Wind Farms, along with renewable resource projects under construction. Starting in 2019, we added an additional 1,315 MW of mostly onshore wind generation to satisfy New England RPS goals.

2.4 Conventional Resource Additions

LAI reviewed the interconnection queues for ISO-NE, PJM, and NYISO to determine near-term additions. For ISO-NE and PJM, projects with an executed interconnection service agreement were placed in-service according to the projected in-service data in the ISA. For NYISO, projects with an executed ISA and an accepted class-year cost allocation were placed in service.

Over the long term, we assumed that new conventional generation would be added (beyond new renewable resources) in the form of simple cycle and combined cycle plants in a 1:2 capacity ratio to meet load growth, offset retirements, and achieve the reserve margins in Table 3 below to maintain long-term system reliability over the Study Period. These are the types of plants that have been added across the study region in recent years due to their relatively low capital cost, high efficiency, operational flexibility, and low fuel costs. We added 4,463 MW of gas-fired simple cycle and combined cycle plants throughout the ISO-NE system over the Study Period. LAI updated the simple cycle and combined cycle performance data based on the publically available information.

Table 3. Target ISO / RTO Reserve Margins

ISO-NE	15%
NYISO	17%
PJM (MAAC)	15.7%

2.5 HVDC Additions

LAI has incorporated the following HVDC transmission projects that have received key FERC and RTO approvals:

- Northern Pass Transmission, which is assumed to be operational by January 1, 2018, with 1,200 MW of capacity and a capacity factor of 78.7% in 2018, increasing to 84.2% by 2024, based on a December 7, 2010 Report on LMP and Congestion Impacts by Charles River Associates.

- Champlain Hudson Power Express, which is assumed to be operational by January 1, 2018 with 1,000 MW of capacity and a 95% utilization rate, based on information provided by TDI-New England.

2.6 Generation Unit Retirements

Older fossil-fuel plants in ISO-NE and other markets are coming under increasing economic pressure as low energy and capacity revenues and stricter environmental regulations make it more difficult to cover ongoing O&M expenses and capital investments. All of the regions LAI modeled will have some level of plant retirements over the Study Period. LAI adopted the plant retirements contained in the U.S. Energy Information Administration's ("EIA") 2014 Annual Energy Outlook ("AEO 2014") that lists retirements by year, region, and technology type, as summarized below. According to the AEO 2014, retirements are calculated as follows:

The AEO 2014 projections include planned retirements as reported to EIA on the Form EIA-860 and in RTO planning documents. LAI checked the reasonableness of the AEO 2014 retirements for the first five years, prior to 2019, and found they were generally consistent with other retirement estimates. We then updated the AEO 2014 retirements with the most recent ISO-NE, NYISO, and PJM data. The updated retirements are included in the table below.

Table 4. Plant Retirements (MW)

	AEO 2014 ISO-NE	Updated ISO-NE	AEO 2014 NYISO	Updated NYISO	AEO 2014 MAAC	Updated MAAC
2014-2018	2,374	3,005	322	831	4,735	4,882
2019	-	-	-	-	-	-
2020	-	-	-	-	615	637
2021	-	-	234	-	-	-
2022	-	-	-	-	2	-
2023	-	-	-	-	-	-
2024	-	-	264	263	325	371
2025	-	-	-	-	-	-
2026	-	-	-	-	-	-
2027	-	-	-	-	-	-
2028	-	-	-	-	8	-

ISO-NE

The AEO 2014 forecasts ISO-NE to have 2.37 GW retired in the five year period 2014-2018. This value is roughly equivalent to the expected retirements of Vermont Yankee (615 MW) plus Brayton Point (1561 MW). Based on Non-Price Retirement Requests filed between 2011 and 2013, we also anticipate that Bar Harbor #1-4, Bridgeport Harbor #2, Howland #1-3, Medway #IC1-4, Mount Tom #1, Potter Station 2 #IC1, Salem Harbor #3-4, Veazie A #1-17, and Harris Energy Realty, totaling 852 MW, will retire at some point between 2014 and 2018 as shown in the column titled Updated ISO-NE.

NYISO

The AEO 2014 forecasts NYISO to have 0.32 GW retired in the same five year period, mostly in upstate New York. This value is very close to NYISO's own estimate 309 MW for Cayuga 1&2 coal-fired plants scheduled to retire in July 2017. Based on NYISO Gold Book data, we also anticipate that Dunkirk #2, Selkirk I-II and Ravenswood #GT7 will retire between 2014 and 2018. The next AEO 2014 retirements are (i) 0.23 GW of combustion turbines / diesels in Long Island, which could not be matched with any resources in the NYISO resource mix and (ii) 0.26 GW of oil / natural gas steam plants and combustion turbines / diesels in New York City / Westchester in 2024, which we assume are East River #6 and #1, respectively, totaling 263 MW.

PJM / MAAC

The AEO 2014 forecasts MAAC to have 4.74 GW retired in the same five year period, very close to PJM's own estimate of 4,882 MW of Future Deactivations (as of October 1, 2014). The next AEO 2014 retirement is 0.61 GW of nuclear capacity in 2020 which we assume to be Oyster Creek #1 (637MW) and 0.32 GW of oil / natural gas-fired steam plants in 2024 which we assume are BL England #3, Gould Street #3, and Herbert A. Wagner #1, totaling 371 MW.

2.7 Demand Side Management

Demand response, conservation, and energy efficiency are built into the load and capacity forecasts for ISO-NE and other markets. Demand response resources in ISO-NE and PJM that cleared the latest forward capacity auction (FCA8 and the 2017/18 BRA, respectively) were modeled, along with special case resources in NYISO. DSM projects have proven to be fairly price sensitive and face significant uncertainty due to the ongoing litigation in the federal courts. Therefore for the Study Period, LAI assumed no change in the level of demand response, conservation, and energy efficiency beyond what are contained in the ISO / RTO load forecasts.

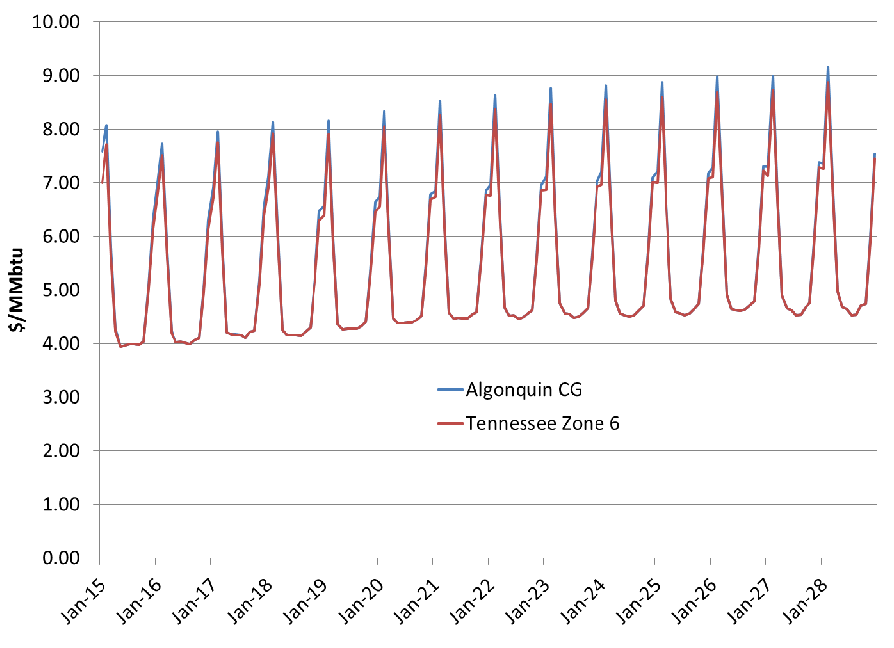
3 Fuel Price Forecasts

LAI's forecast of wholesale energy prices utilized updated projections of generation fuel prices used in Vermont, New England, and the surrounding markets areas. Derivation of the key components of the fuel price forecast is described below.

3.1 Oil Price Forecast

LAI's forecast of fuel oil prices is based on New York Mercantile Exchange ("NYMEX") forward prices for West Texas Intermediate ("WTI") crude oil, the primary U.S. crude benchmark. NYMEX prices are closing prices from October 7, 2014, which provides a WTI price curve pricing through 2022. Prices for various refined petroleum products, including ultra-low sulfur distillate and residual fuel oils are based on the historical statistical relationships between each product and WTI.

Figure 2. ISO-NE Natural Gas Price Forecast



3.2 Natural Gas Price Forecast

Our forecast of Henry Hub natural gas prices is based on the NYMEX natural gas prices that settled on October 7, 2014. The Henry Hub curve provides for pricing through 2026. Thereafter, the curve is extended based on the indicated trendline. In order to calculate delivered gas prices we add basis values for regional market pricing points from a forecast we developed using GPCM, an-industry leading simulation model of the North American gas pipeline system that we license from RBAC, Inc. We also estimated additional adders for generators connecting through local gas utilities. The Algonquin Citygate and Tennessee Zone 6 gas prices have the greatest relevance to New England and are illustrated above:

3.3 Coal Price Forecast

To forecast delivered coal prices for New England, LAI utilized the basin price forecasts for the Northern Appalachian ("NAPP") and Central Appalachian ("CAPP") basins from AEO 2014. Delivered prices are developed using the basin forecasts of relevance adjusted for the cost of transporting the coal to market. Coal prices for New England generators are based on a mix of NAPP and CAPP coal and an assumption of approximately $30/ton transportation cost (which escalates at our general rate of inflation at 2%).

3.4 Nuclear Fuel Price Forecast

Our forecast of nuclear fuel prices is based on AEO 2014 data.

4 ENVIRONMENTAL COMPLIANCE

The electric market simulation models incorporate current and anticipated state and federal environmental compliance requirements over the study horizon.

4.1 Emission Allowance Price Forecast

AURORAxmp incorporates NO_x, SO_2, and CO_2 emission rates and allowance costs as applicable to fossil fueled generators in the study region. Allowances, including those which are allocated to generators at no cost as well as auctioned allowances, are treated as variable operating costs and are priced at their opportunity cost, that is, the market price for the vintage year that the allowance is "used" or retired.

Both NO_x and SO_2 allowance prices over the last few years have been driven down by the retrofit of emission control equipment (*e.g.*, selective catalytic reduction and flue gas desulfurization) on many fossil-fired plants, and overall reduction in emissions of those pollutants, particularly in the Northeast. In addition, uncertainty occasioned by litigation surrounding implementation of EPA's Cross-State Air Pollution Rule ("CSAPR") has kept allowance trading thin and prices weak. In April 2014 the U.S. Supreme Court reversed a previous lower court ruling which had vacated CSAPR. CSAPR does not apply to the New England states, but several New England states have cap and trade programs based on CSAPR's predecessor, the federal Clean Air Interstate Rule ("CAIR").

For modeling purposes, we have assumed that NO_x and SO_2 allowance prices under both reinstated CSAPR and state CAIR programs remain consistent with the historical prices under the prior NO_x and SO_2 cap-and-trade program under CAIR. CAIR Annual NO_x allowances have recently traded at $44/ton, and Seasonal NO_x allowance prices at $20/ton. LAI assumed that Annual NO_x prices escalated (at inflation) from $55.20/ton in 2019 and seasonal NO_x prices escalated (at inflation) starting at $31.47/ton in 2019 over the course of the study period. SO_2 prices remain below $2/ton.

CO_2 allowances apply only to the fossil-fired plants within the footprint of the Regional Greenhouse Gas Initiative ("RGGI"). LAI utilized recent RGGI auction clearing prices combined with the price projections in the 2012 RGGI Program Review as a basis to forecast RGGI allowance prices. A trendline extended the forecast beyond 2020. We assumed that the RGGI allowance price begins at $9.61/ton in 2019 and escalates over time by the same trendline. LAI did not assume any other prices on CO_2 emissions such as a nationwide carbon tax in this study.

4.2 Emission Rates

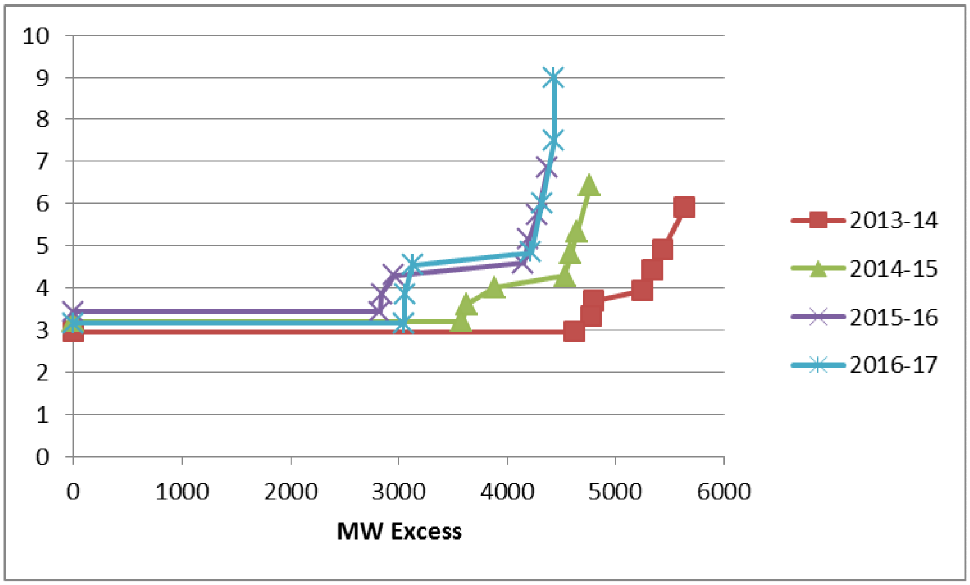
EPIS uses sources of historical emissions data to calculate emissions rates for generation resources. Emission rates for NO_x, SO_2, and CO_2 in the AURORAxmp database are derived from several sources, such as continuous emissions monitoring ("CEMS) data in the EPA Clean Air Markets database, EIA plant level data, and further analysis by EPIS, who provides the AURORAxmp database. For new generic resources, LAI assumed emissions rates for recent gas-fired combined cycle and combustion turbine units based on a review of several publically available sources.

5 CAPACITY PRICE FORECAST

ISO-NE sets locational capacity prices and quantities through its Forward Capacity Market ("FCM") for delivery three years in advance. ISO-NE conducts annual Forward Capacity Auctions ("FCAs") that take account of a resource's capacity rating plus its availability. The FCAs will change over the next few years, prior to the Study Period: (i) FERC approved a proposal to replace the vertical demand curve with a sloped demand curve; (ii) a U.S. Court of Appeals ruling vacated FERC's Order 745 requiring ISOs and RTOs to include demand-side resources in wholesale markets; and (iii) ISO-NE will implement "Pay-for-Performance." LAI adopted the first change, but there is considerable uncertainty about the transition of demand-side resources from wholesale markets to state-regulated retail markets and the impacts of Pay-for-Performance. Thus those two changes have not been considered.

LAI estimated the shape and slope of the relevant portion of the supply curves for FCA #4-#7, *i.e.* where they intersect the demand curve, based on auction data provided by ISO-NE. Next we generated sloped demand curves based on the FERC-approved parameters as if they had been utilized for FCA #4-#7. Lastly, we calculated the impact that 500 MW of new capacity would have had on the ISO-NE capacity clearing price for FCAs #4-#7 by shifting the supply curves to the right by 500 MW.

Figure 3. FCA #4-#7 Supply Curves



The per-customer benefit was estimated assuming that the average Vermont residential ratepayer uses 600 kWh/month, equivalent to 0.82 kW/hour of demand on average. Using hourly load data provided by ISO-NE for 2013, I determined that the average load factor for a Vermont customer is 68%, calculated as the average ratio of hourly demand to the 2013 peak for all hours in that year, equivalent to a 1.21 kW contribution to peak load per residential ratepayer.