New York ISO
Independent System Operator

Appendix E

2021-2040 System & Resource Outlook (The Outlook)

A Report from the New York Independent System Operator

September 22, 2022

Table of Contents

Appendix E: Study Assumptions and Methodology

This appendix describes model preparation, framework, and assumptions that makeup the Baseline, Contract, and Policy Cases. Many of the assumptions in the Baseline Case also apply to the Contract Case. Similarly, the Policy Case is based off the Contract Case, including additional assumptions pertaining to the application of state policies. These sections go through the assumptions in each case.

Appendix E.1: Baseline Case Assumptions

As described in Section 31.3.1 of Attachment Y, the System & Resource Outlook will align with the Reliability Planning Process, and the ten-year Study Period covered by the most recently approved CRP shall be the first ten years of the System & Resource Outlook Study Period.

The data utilized in the Baseline Case simulations for the System & Resource Outlook is largely derived from the 2021-2030 CRP, 2021 Gold Book, and The Outlook Assumptions Matrix (Appendix C: Production Cost Assumptions Matrix). Major components of the data include base load flow data, unit heat rates, unit capacities, load forecasts, load shape, fuel and emissions allowance price forecasts, transmission constraint modeling, both simulated and actual and scheduled interchange values, and operation and maintenance (O&M) cost.

Figure 1: Major Model Inputs and Changes

Major Modeling Inputs	
Input Parameter	**Change from 2019 CARIS 1**
Load Forecast	comparable in value, slightly lower
	Modeled Large Loads from the 2021 Load and Capacity Data Report
Natural Gas Price Forecast	higher
CO_2 Price Forecast	higher
NO_x Price Forecast	Annual NO_X lower, Ozone NO_X high in earlier years and lower in later years
SO_2 Price Forecast	same
Hurdle Rates	PJM lower, MISO higher
Modeling Changes	
MAPS Software Upgrades	GE MAPS Version 14.400.1404 was used for production cost simulation
PJM/NYISO JOA	same
NY Transmission Upgrades	LTP Updates on Con Edison 345/138 kV PAR controlled feeder lines in NY city.
	STRP solution for addressing 2023 short-term need
	SR in-service on following 345 kV cables: 71, 72, M51, M52
	Bypassing the SR on the following 345 kV cables: 41, 42, Y49

E.1.1. Baseline Case Load and Capacity Forecast

The load and capacity forecast used in the Baseline Case was based on the 2021 Gold Book and accounts for the impact of programs such as energy efficiency, electrification, and the Peaker Rule[1]. Baseline Case load forecasts are presented in Figure 2 and Figure 3. Figure 2 presents the Annual Zonal Energy in gigawatt-hours (GWh) and Figure 3 presents summer non-coincident peak demand in megawatts (MW). Figure 4 presents the timeline of generation changes made in NYCA, and Figure 5 presents annual NYCA capacity for the Baseline Case.

Figure 2: Annual Zonal Energy (GWh)

Year	A	B	C	D	E	F	G	H	I	J	K	NYCA
2021	14,866	10,013	15,911	5,571	8,110	12,367	9,588	2,916	5,824	48,647	20,708	154,521
2022	15,774	10,062	16,096	6,696	8,153	12,441	9,513	2,927	5,841	48,491	20,511	156,502
2023	16,948	10,053	16,485	7,303	8,180	12,445	9,465	2,934	5,849	48,021	20,213	157,896
2024	17,130	10,049	16,658	7,478	8,197	12,448	9,428	2,937	5,810	47,656	20,025	157,816
2025	17,362	9,952	16,776	7,657	8,240	12,364	9,440	2,939	5,771	47,477	19,817	157,796
2026	17,597	9,901	16,797	7,815	8,283	12,346	9,441	2,950	5,755	47,383	19,601	157,868
2027	17,729	9,850	16,787	7,967	8,312	12,354	9,459	2,961	5,765	47,442	19,566	158,192
2028	17,724	9,833	16,770	7,969	8,334	12,440	9,482	2,974	5,784	47,627	19,708	158,644
2029	17,743	9,830	16,740	7,968	8,347	12,503	9,489	2,981	5,809	47,879	19,912	159,200
2030	17,818	9,840	16,730	7,973	8,378	12,570	9,548	2,992	5,838	48,174	20,189	160,050
2031	17,872	9,875	16,685	7,982	8,408	12,679	9,594	3,006	5,882	48,573	20,454	161,009
2032	17,935	9,910	16,660	7,990	8,441	12,784	9,648	3,022	5,931	49,025	20,715	162,061
2033	18,026	9,956	16,662	8,000	8,473	12,899	9,725	3,044	5,993	49,570	20,986	163,335
2034	18,137	10,006	16,688	8,011	8,518	13,002	9,803	3,071	6,058	50,153	21,265	164,713
2035	18,263	10,069	16,747	8,025	8,563	13,110	9,898	3,100	6,134	50,812	21,579	166,299
2036	18,389	10,133	16,836	8,039	8,610	13,224	10,001	3,134	6,217	51,535	21,893	168,013
2037	18,515	10,207	16,950	8,055	8,658	13,339	10,113	3,172	6,306	52,330	22,222	169,866
2038	18,651	10,283	17,085	8,070	8,713	13,468	10,239	3,217	6,402	53,168	22,553	171,849
2039	18,798	10,373	17,238	8,091	8,775	13,609	10,398	3,260	6,511	54,125	22,904	174,083
2040	18,963	10,484	17,425	8,112	8,852	13,757	10,569	3,310	6,622	55,071	23,271	176,435

[1] The NYS Department of Environmental Conservation "Peaker Rule", 6 NYCRR Subpart 227-3, which phases in ozone season compliance obligations between 2023 and 2025, will impact simple cycle combustion turbines located mainly in the lower Hudson Valley, New York City, and Long Island.

Figure 3: Summer Non-Coincident Peak Demand by Zone (MW)

Year	A	B	C	D	E	F	G	H	I	J	K
2021	2,934	2,127	3,003	845	1,552	2,620	2,447	663	1,444	11,298	5,512
2022	3,037	2,072	3,113	953	1,650	2,718	2,465	668	1,425	11,422	5,455
2023	3,194	2,077	3,210	1,038	1,733	2,758	2,477	670	1,424	11,407	5,365
2024	3,257	2,092	3,278	1,077	1,799	2,802	2,493	671	1,419	11,405	5,294
2025	3,226	2,160	3,234	1,080	1,791	2,811	2,489	668	1,442	11,384	5,213
2026	3,266	2,164	3,260	1,104	1,823	2,839	2,494	669	1,441	11,399	5,155
2027	3,283	2,172	3,280	1,127	1,851	2,867	2,500	673	1,445	11,464	5,127
2028	3,369	2,117	3,390	1,161	1,930	2,910	2,527	682	1,428	11,548	5,145
2029	3,371	2,124	3,400	1,167	1,950	2,935	2,539	686	1,437	11,638	5,178
2030	3,378	2,127	3,406	1,173	1,969	2,960	2,556	691	1,446	11,724	5,236
2031	3,287	2,186	3,313	1,147	1,931	2,972	2,554	693	1,483	11,808	5,277
2032	3,294	2,189	3,313	1,153	1,946	2,997	2,567	697	1,495	11,885	5,350
2033	3,398	2,133	3,408	1,191	2,017	3,039	2,603	709	1,480	11,955	5,451
2034	3,410	2,135	3,411	1,198	2,031	3,063	2,617	713	1,490	12,023	5,527
2035	3,421	2,140	3,413	1,204	2,044	3,085	2,634	718	1,500	12,088	5,603
2036	3,431	2,143	3,414	1,211	2,054	3,106	2,650	725	1,510	12,149	5,672
2037	3,336	2,202	3,327	1,180	2,012	3,109	2,639	721	1,546	12,218	5,718
2038	3,343	2,202	3,333	1,188	2,021	3,121	2,654	725	1,552	12,274	5,777
2039	3,458	2,156	3,422	1,231	2,083	3,149	2,693	735	1,530	12,307	5,850
2040	3,469	2,164	3,427	1,237	2,090	3,163	2,711	737	1,536	12,354	5,899

Figure 4: Timeline of Major NYCA Modeling Changes

Timeline of Modeling Changes		
Year	**ISD**	**Resource**
2021	7/1/2021	Janis Solar, 20 MW
	7/6/2021	Cassadaga Wind, 126.5 MW
	8/1/2021	Puckett Solar, 20 MW
	9/1/2021	Tayandenega Solar, 20 MW
	11/1/2021	Albany County 1 Solar, 20 MW
		Albany County 2 Solar, 20 MW
		Greene County 1 Solar, 20 MW
		Greene County 2 Solar, 10 MW
		North Country Solar, 15 MW
		Pattersonville Solar, 20 MW
		ELP Stillwater Solar, 20 MW
		Darby Solar, 20 MW
		Branscomb Solar, 20 MW
	12/1/2021	Grissom Solar, 20 MW
		Regan Solar, 20 MW
		Rock District Solar, 20 MW
		Roaring Brook Wind, 79.7 MW
2022	1/1/2022	WNY Stamp Load
		Greenidge Load
		Somerset Load
		Cayuga Load
		NCDC Load
	3/1/2022	Skyline Solar, 20 MW
	5/1/2022	Dog Corners Solar, 20 MW
	8/1/2022	Sky High Solar, 20 MW
	9/1/2022	Eight Point Wind Energy, 101.8 MW
		Number 3 Wind Energy, 103.9 MW
	10/1/2022	Martin Solar, 20 MW
		Bakerstrand Solar, 20 MW
	12/1/2022	Scipio Solar, 18 MW
		Niagara Solar, 20 MW
		Ball Hill Wind, 100 MW
2023	6/1/2023	Watkins Road Solar, 20 MW
	7/1/2023	Baron Winds, 238.4 MW
2024		Athens SPS retired on 1/2024

Figure 5: NYCA Capacity (MW)

Year	A	B	C	D	E	F	G	H	I	J	K	NYCA
2021	3,497	771	6,650	2,056	1,223	4,734	4,704	1,088	-	9,618	5,167	39,508
2022	3,570	791	6,810	2,075	1,347	4,734	4,704	52	-	9,602	5,154	38,839
2023	3,570	791	7,048	2,075	1,367	4,734	4,666	52	-	9,075	5,043	38,421
2024	3,570	791	7,048	2,075	1,367	4,734	4,666	52	-	9,075	5,043	38,421
2025	3,637	791	7,048	2,056	1,367	4,734	4,666	52	-	9,047	5,043	38,441
2026	3,637	791	7,048	2,056	1,367	4,734	4,666	52	-	9,047	5,043	38,441
2027	3,637	791	7,048	2,056	1,367	4,734	4,666	52	-	9,047	5,043	38,441
2028	3,570	791	7,048	2,075	1,367	4,734	4,666	52	-	9,047	5,043	38,393
2029	3,570	791	7,048	2,075	1,367	4,734	4,666	52	-	9,047	5,043	38,393
2030	3,637	791	7,048	2,056	1,367	4,734	4,666	52	-	9,047	5,043	38,441
2031	3,637	791	7,048	2,056	1,367	4,734	4,666	52	-	9,047	5,043	38,441
2032	3,637	791	7,048	2,056	1,367	4,734	4,666	52	-	9,047	5,043	38,441
2033	3,570	791	7,048	2,075	1,367	4,734	4,666	52	-	9,047	5,043	38,393
2034	3,570	791	7,048	2,075	1,367	4,734	4,666	52	-	9,047	5,043	38,393
2035	3,570	791	7,048	2,075	1,367	4,734	4,666	52	-	9,047	5,043	38,393
2036	3,637	791	7,048	2,056	1,367	4,734	4,666	52	-	9,047	5,043	38,441
2037	3,637	791	7,048	2,056	1,367	4,734	4,666	52	-	9,047	5,043	38,441
2038	3,637	791	7,048	2,056	1,367	4,734	4,666	52	-	9,047	5,043	38,441
2039	3,570	791	7,048	2,075	1,367	4,734	4,666	52	-	9,047	5,043	38,393
2040	3,570	791	7,048	2,075	1,367	4,734	4,666	52	-	9,047	5,043	38,393

E.1.2. Transmission Model

The Outlook production cost analysis utilizes a bulk power system representation for the entire Eastern Interconnection, which includes the power system in the United States and Canadian Provinces East of the Rocky Mountains, excluding the Western Electricity Coordinating Council and Texas. The Outlook model includes an active and detailed representation for the power systems and electricity markets of the NYISO, ISO-New England, IESO, and PJM Interconnection Control Areas. The transmission representation of the three neighboring control areas is derived from the most recent CRP case and include changes expected to significantly impact NYCA congestion.

E.1.3. New York Control Area Transfer Limits

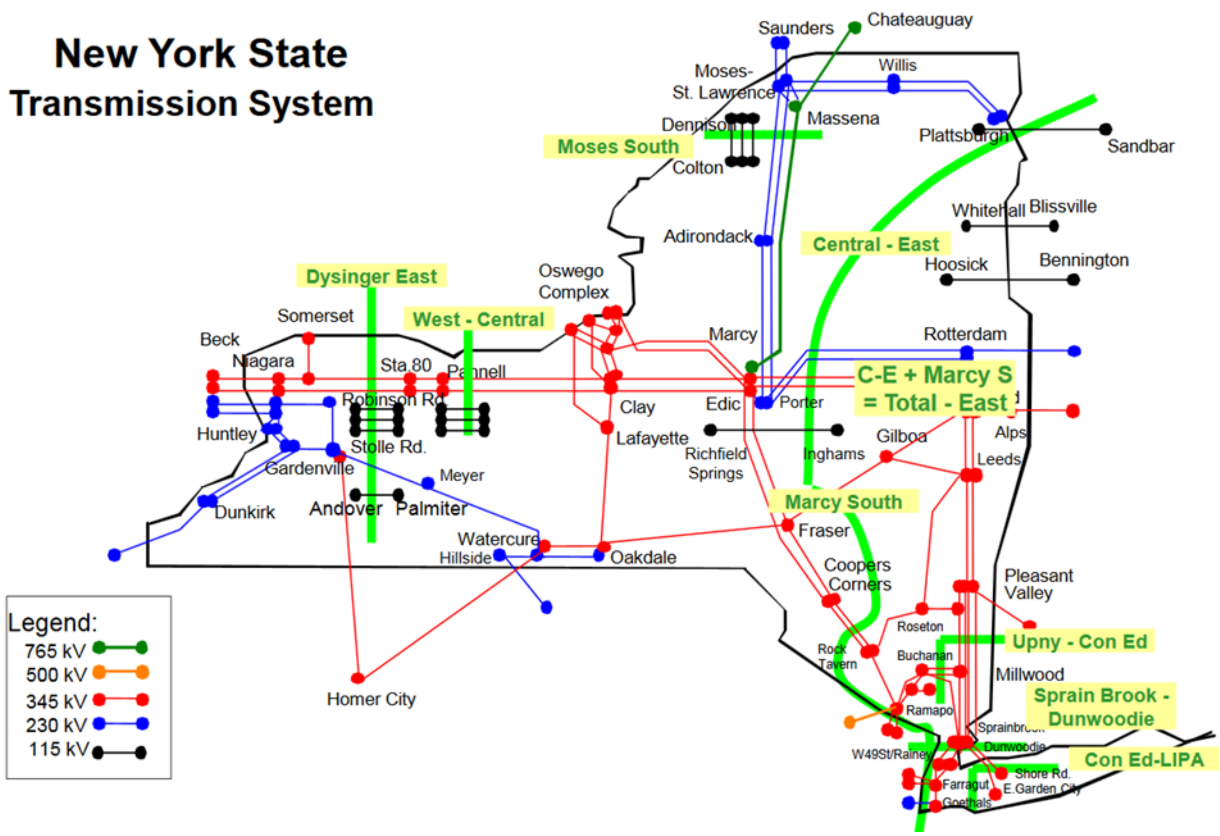
The Outlook utilizes normal transfer criteria for MAPS software simulations to determine system production costs. Normal thermal interface transfer limits for The Outlook report are not directly utilized from the thermal transfer analysis performed using TARA software.[2] Instead, The Outlook uses the most severe limiting monitored lines and contingency sets identified from analysis using TARA software and from historical binding constraints. More details on the round-trip analysis used to develop contingency sets can be found in Appendix E.2.2.

For voltage and stability-based limits, the normal and emergency limits are assumed to be the same.

[2] PowerGEM's Transmission Adequacy and Reliability Assessment ("TARA") software is a steady-state power flow software tool with modeling capabilities and analytical applications.

For NYCA interface stability transfer limits, the limits are consistent with the operating limits.[3] The Central East interface was modeled with a unit sensitive nomogram reflecting the algorithm utilized by NYISO Operations.[4] Adjustments were made to this nomogram to accommodate new transmission projects that impact the interface limit.

Figure 6: NYISO 115 kV and Above Transmission Map



New York Control Area System Changes, Upgrades and Resource Additions

System changes modeled for 2019 and beyond are as follows:

a) Conforming the modeling of the PJM/NYISO interface to the current NYISO-PJM Joint Operating Agreement

b) Seasonal (winter) by-pass of the Marcy South Series Compensation (MSSC)

[3] https://www.nyiso.com/documents/20142/3691079/NYISO_InterfaceLimtsandOperatingStudies.pdf/

[4] https://www.nyiso.com/documents/20142/3692791/CE_VoltageandStability_Limit_ReportFinalOCApproved3-17-2016.pdf

c) Erie – South Ripley series reactor in-service (2019)

d) Rainey – Corona PAR in-service (2019)

e) Leeds Hurley SDU in-service (2021)

f) Cedar Rapids Transmission Upgrade (2021)

g) LTP updates on Con Edison 345/138 kV PAR controlled feeder lines in New York City (2021)

h) Empire State Line/Western NY Public Policy Transmission project modeled in-service (2022)

i) STRP solution for addressing 2023 short-term need – Series Reactor (SR) status changes, starting 2023, through 2030

j) Placing in service the SR on the following 345 kV cables: 71, 72, M51, M52

k) Bypassing the SR on the following 345 kV cables: 41, 42, Y49

l) Selected AC Public Policy Transmission projects (segments A and B) modeled in-service (2024)

E.1.4. Fuel Forecasts

The fuel price forecasts for The Outlook[5] are based on the U.S. Energy Information Administration's ("EIA")[6] current national long-term forecast of delivered fuel prices, which is released each spring as part of its Annual Energy Outlook. The figures in this forecast are in nominal dollars. The same fuel forecast is utilized for all study cases.

New York Fuel Forecast

In developing the New York fuel forecast, regional adjustments were made to the EIA fuel forecast to reflect fuel prices in New York. Key sources to estimate the relative differences for fuel-oil prices in New York are the Monthly Utility and non-Utility Fuel Receipts and Fuel Quality Data reports based on the information collected through Form EIA-923.[7] The regional adjustments for natural gas prices are based on a comparative analysis of monthly national delivered prices published in EIA's Short Term Energy Outlook and spot prices at the selected trading hubs. The base annual forecast series from the Annual Energy Outlook are adjusted to reflect the New York prices relative to the national delivered prices as described below.

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[5] https://www.nyiso.com/documents/20142/26278859/System_Resource_Outlook-Fuel_Forecast.xlsx

[6] www.eia.doe.gov

[7] Prior to 2008, this data was submitted via FERC Form 423. 2008 onwards, the same data are collected on Schedule 2 of the new Form EIA-923. See http://www.eia.doe.gov/cneaf/electricity/page/ferc423.html. These figures are published in Electric Power Monthly.

Natural Gas

For the 2021 Outlook, the New York Control Area is divided into four (4) gas regions: Upstate (Zones A to E), Midstate (Zones F to I), Zone J, and Zone K.

Given that gas-fueled generators in a specific NYCA zone acquire their fuel from several gas-trading hubs, each regional gas price is estimated as a weighted blend of individual hubs based on the sub-totals of the generators' annual generation megawatt-hour levels. The regional natural gas price blends for the regions are as follows:

- Zones A to E – Dominion South (91%), Tetco M3 (7%), & Columbia (2%);
- Zones F to I – Tennessee Zone 6 (62%), Iroquois Zone 2 (28%), Algonquin (7%), and Tetco M3 (3%);
- Zone J – Transco Zone 6 (100%);
- Zone K – Iroquois Zone 2 (51%) & Transco Zone 6 (49%)

The forecasted regional adjustment, which reflects the differential between the blended regional price and the national average, is calculated as the three-year weighted-average of the ratio between the regional price and the national average delivered price from the Short-Term Energy Outlook.[8] Forecasted fuel prices for the gas regions are shown in Figure 7 through Figure 10.

Fuel Oil

Based on EIA forecasts published in its Electric Power Projections by Electricity Market Module Regions (see Annual Energy Outlook 2021, Reference Case), price differentials across regions can be explained by a combination of transportation/delivery charges and taxes. Regional adjustments were calculated based on the relative differences between EIA's national and regional forecasts of Distillate (Fuel Oil #2) and Residual (Fuel Oil #6) prices. For illustrative purposes, forecasted prices for Distillate Oil and for Residual Oil are shown in Figure 7 through Figure 10.

Coal

The data from EIA's Electric Power Projections by Electricity Market Module Regions was also used to arrive at the forecasted regional delivered price adjustment for coal. (The published figures do not make a distinction between the different varieties of coal; *i.e.,* bituminous, sub-bituminous, and lignite). No coal plants are modeled in service in New York past 2020, and this coal price forecast applies only to units in

[8] The raw hub-price is 'burdened' by an appropriate level of local taxes and approximate delivery charges. In light of the high price volatility observed during winter months, the 'basis' calculation excludes data for January, February and December.

external areas.

Seasonality and Volatility

All average monthly fuel prices, with the exception of coal and uranium, display somewhat predictable patterns of fluctuations over a given 12-month period. In order to capture such seasonality, the NYISO estimated seasonal factors using standard statistical methods.[9] The multiplicative factors were applied to the annual forecasts to yield forecasts of average monthly prices.

The data used to estimate the 2021 seasonal factors are as follows:

- Natural Gas: Raw daily prices from S&P Global/Platts for the various trading hubs incorporated in the regional price blends.
- Fuel Oil #2: EIA's average daily prices for New York Harbor Ultra-Low Sulfur No. 2 Diesel Spot Price. The Outlook assumes the same seasonality for both types of fuel oil.
- The seasonalized time-series represents the forecasted trend of average monthly prices. Because The Outlook uses weekly prices for its analysis, the monthly forecasted prices are interpolated to yield 53 weekly prices for a given year. Furthermore, price "spikes" are layered on these forecasted weekly prices to capture typical intra-month volatility, especially in the winter months. The "spikes" are calculated as five-year averages of deviations of weekly (weighted-average) spot prices relative to their monthly averages. The "spikes" for a given month are normalized such that they sum to zero.

[9] This is a two-step process: First, deviations around a centered 12-month moving average are calculated over the 2016-2020 period; second, the average values of these deviations are normalized to estimate monthly/seasonal factors.

Figure 7: Forecasted Fuel Prices for Zones A-E (Nominal $)

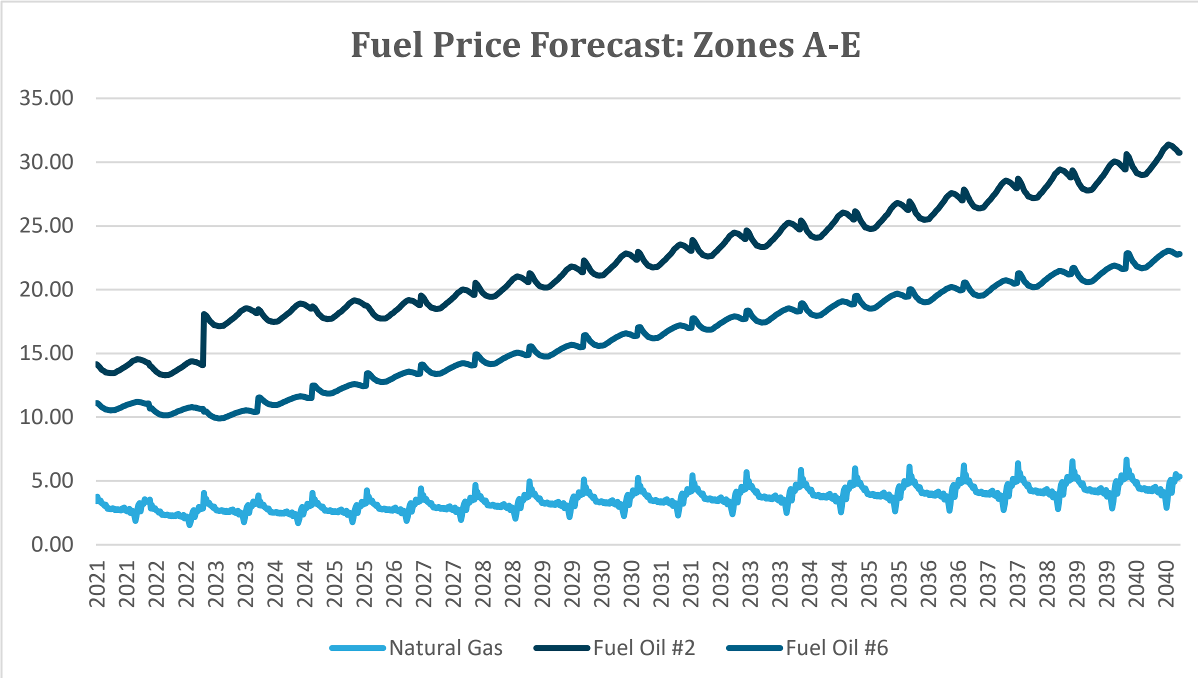


Figure 8: Forecasted Fuel Prices for Zones F-I (Nominal $)

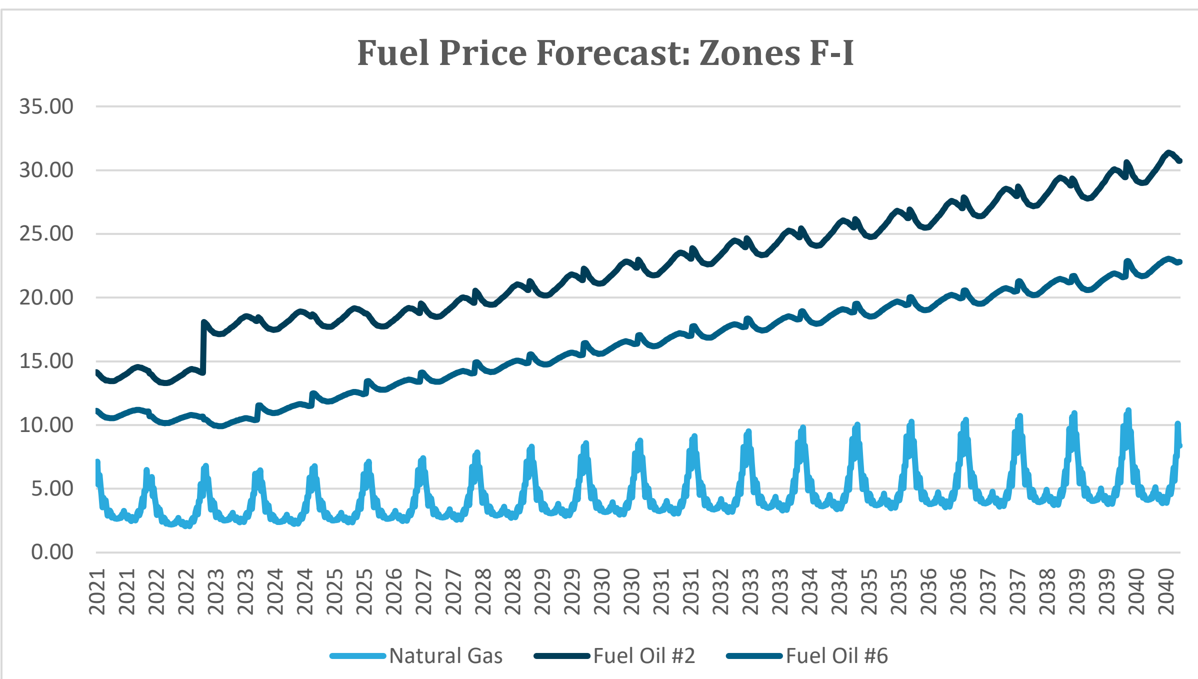


Figure 9: Forecasted Fuel Prices for Zone J (Nominal $)

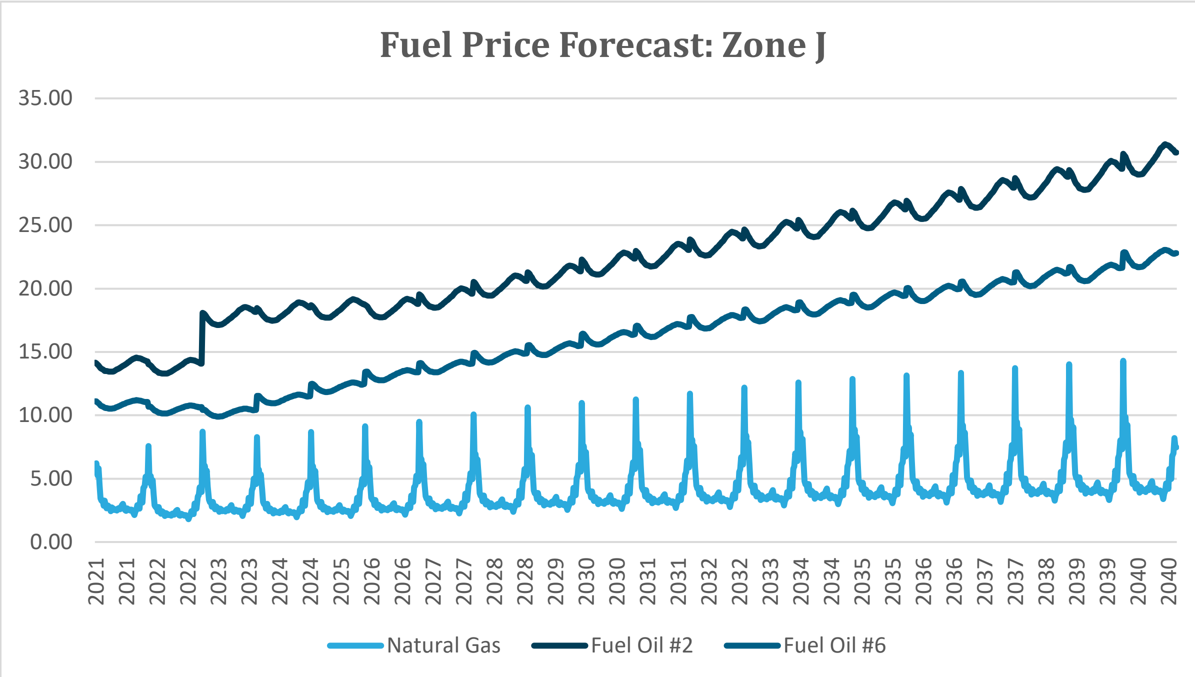
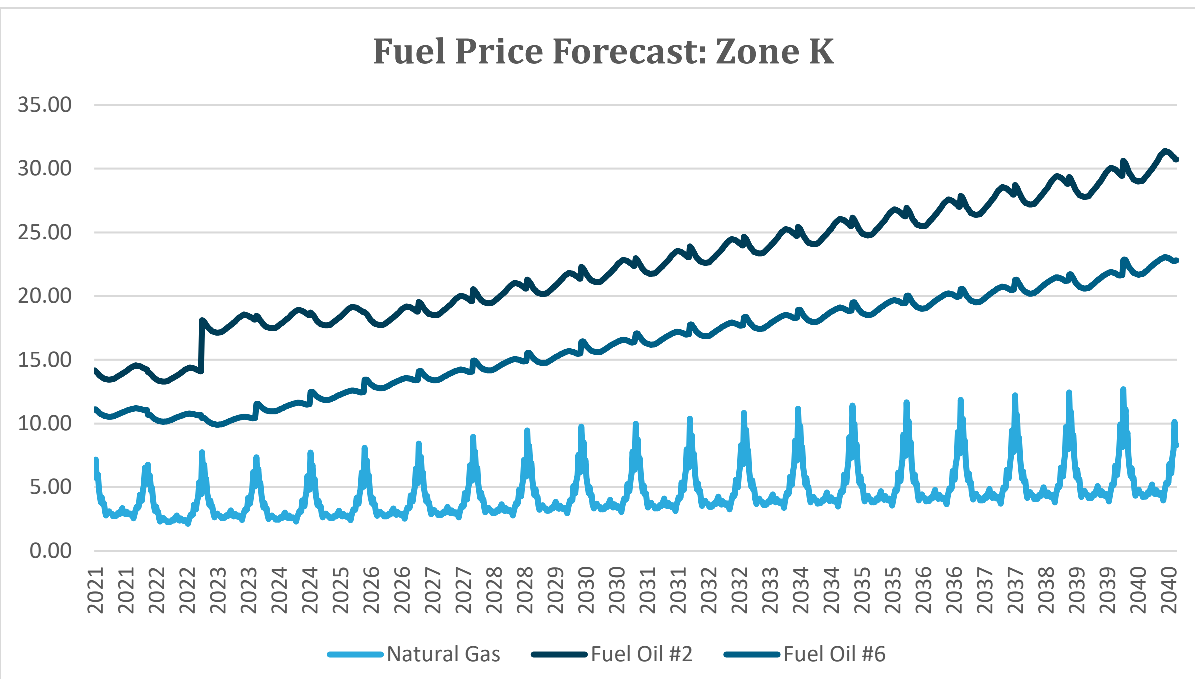


Figure 10: Forecasted Fuel Prices for Zone K (Nominal $)



External Areas Fuel Forecast

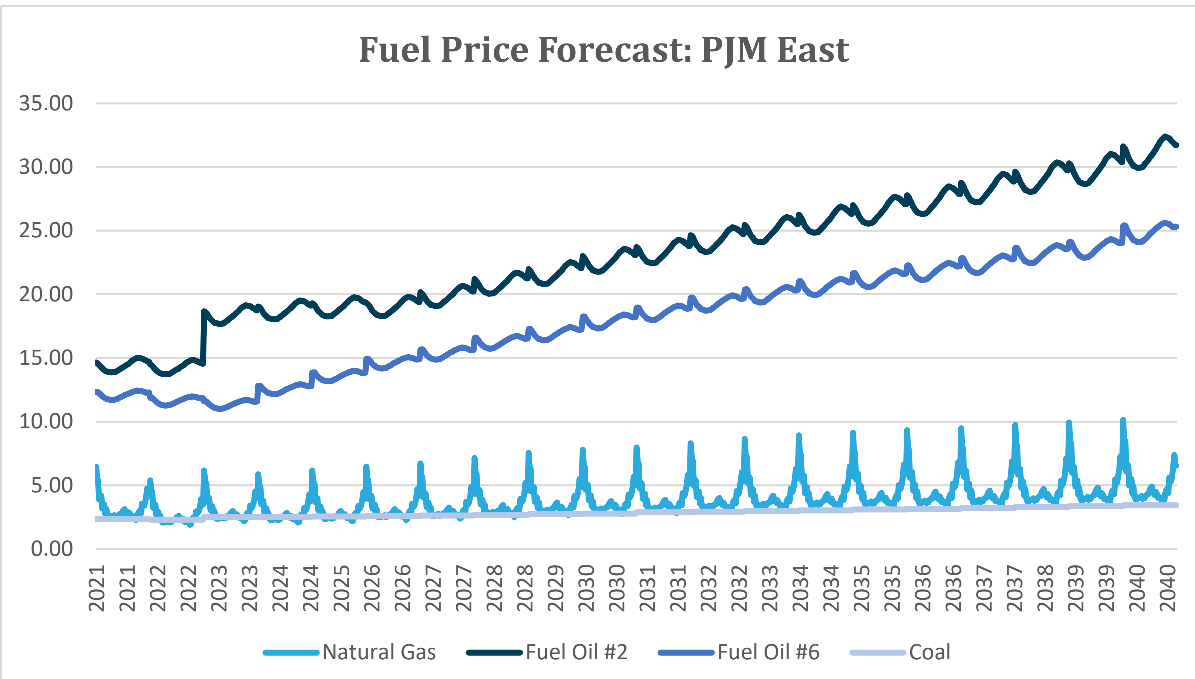
Fuel forecasts for the three external Control Areas, ISO-New England, PJM Interconnection and IESO

Ontario, were also developed. For each of the fuels, the ISO-New England North, ISO-New England South, PJM-East and PJM-West forecasts are based on the EIA data obtained from the same sources as those used for New York. With respect to the IESO Ontario control area, the relative price of natural gas is based on spot-market data for the Dawn hub obtained from SNL Energy.[10] The Outlook does not model any IESO Ontario generation as being fueled by either oil or coal.

Figure 11: External Areas Fuel Forecast Regional Multiplier

Fuel	PJM-East	PJM-West	ISONE-North	ISONE-South	IESO
Fuel Oil #2	0.970	1.080	1.050	1.050	1.125
Fuel Oil #6	1.000	1.100	0.975	0.975	1.075
Natural Gas	0.858	0.821	1.040	1.012	0.898
Coal	1.250	0.950	2.000	2.000	1.300

Figure 12: Forecasted Fuel Prices for PJM East (Nominal $)



[10] Copyright © 2021, SNL Financial LLC

Figure 13: Forecasted Fuel Prices for PJM West (Nominal $)

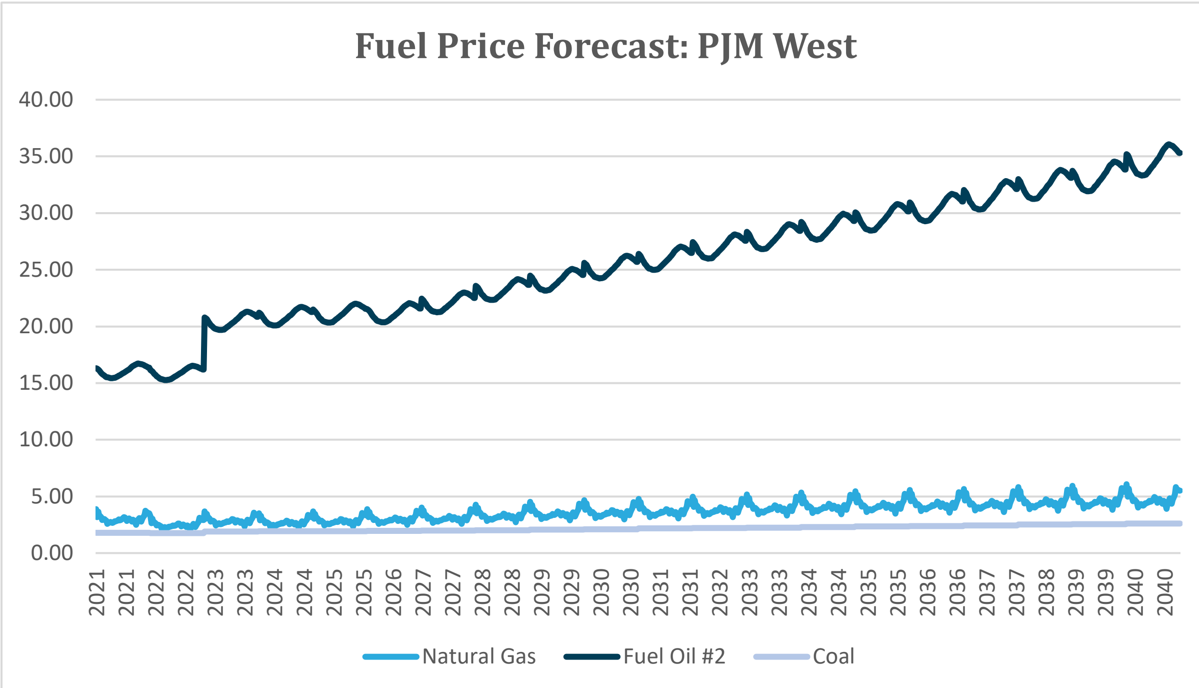


Figure 14: Forecasted Fuel Prices for ISO-NE (Nominal $)

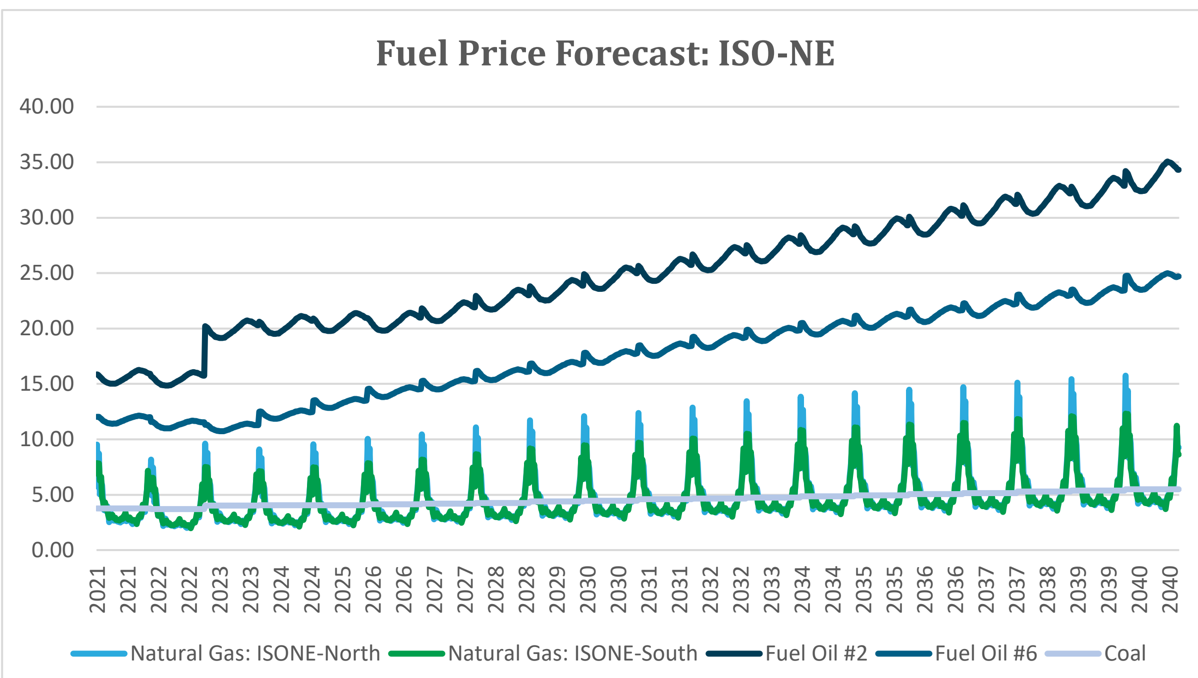
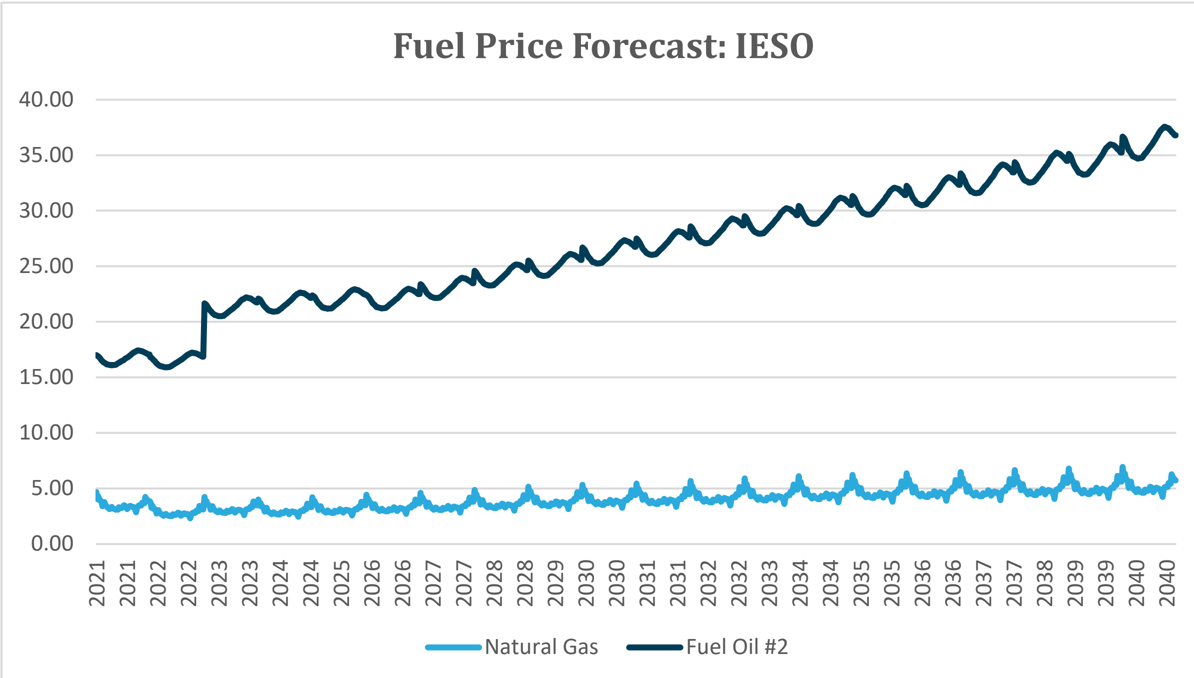


Figure 15: Forecasted Fuel Prices for IESO (Nominal $)



E.1.5. Emission Cost Forecast

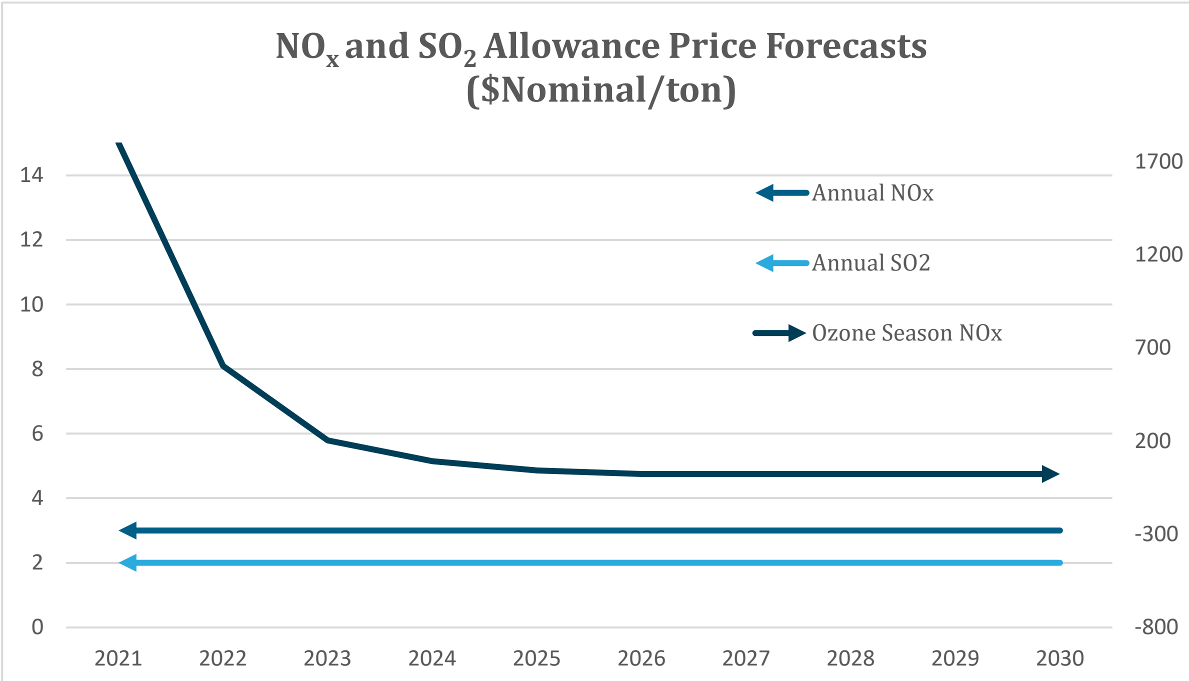
The costs of emission allowances are an increasing portion of generator production costs. Currently, all New York fossil fuel-fired generators greater than 25 MW and most generators in many surrounding states are required to procure allowances in amounts equal to their emissions of SO_2, NO_X, and CO_2.

Baseline Case allowance price forecasts[11] for annual and seasonal NO_X and SO_2 emissions are developed using representative prices at the time the assumptions are finalized. The Cross-State Air Pollution Rule ("CSAPR") NO_X and SO_2 allowances prices reflect persistent oversupply of annual programs, and the expectation that stricter seasonal limitations in the Cross-State Air Pollution Rule Update will continue to be manageable program-wide, leading to price declines as market participants adjust to new operational limits. Figure 16 shows the assumed NO_X and SO_2 allowance price forecasts used in this study.[12]

[11] https://www.nyiso.com/documents/20142/26278859/System_Resource_Outlook-Emissions_Price_Forecast.xlsx

[12] Annual NO_X allowance prices are used October through April; ozone season NO_X allowance prices in addition to Annual NO_X allowance prices are used in May through September.

Figure 16: NO_X and SO_2 Emission Allowance Price Forecasts



The Regional Greenhouse Gas Initiative (RGGI) program for capping CO_2 emissions from power plants includes the six New England states as well as New York, Maryland, Delaware, New Jersey, and Virginia. Historically, the RGGI market has been oversupplied and prices have remained near the floor. In January 2012, the RGGI States chose to retire all unsold RGGI allowances from the 2009-2011 compliance period in an effort to reduce the market oversupply. During the program review that was completed in 2017, the nine RGGI states agreed to an emissions cap reduction from 78 million tons in 2020 to 55 million tons in 2030. New Jersey reentered the program in 2020 with a budget of 20 million tons and Virginia entered in 2021 with a budget of approximately 27 million tons. Both states have committed to commensurate reductions to the other RGGI states. Starting in 2021, an Emission Containment Reserve provides price support by holding back allowances from auction if prices do not exceed predefined threshold levels. Additionally, the states have agreed to adjust banked allowances by reducing the budgets in 2021-2025 by approximately 19 million tons per year. New York began regulating most generators of 15 MW or more in 2021 under RGGI. The 2021 program review is currently underway and is expected to be completed in 2023. For the purposes of this Outlook, Pennsylvania is assumed to join RGGI in 2023.

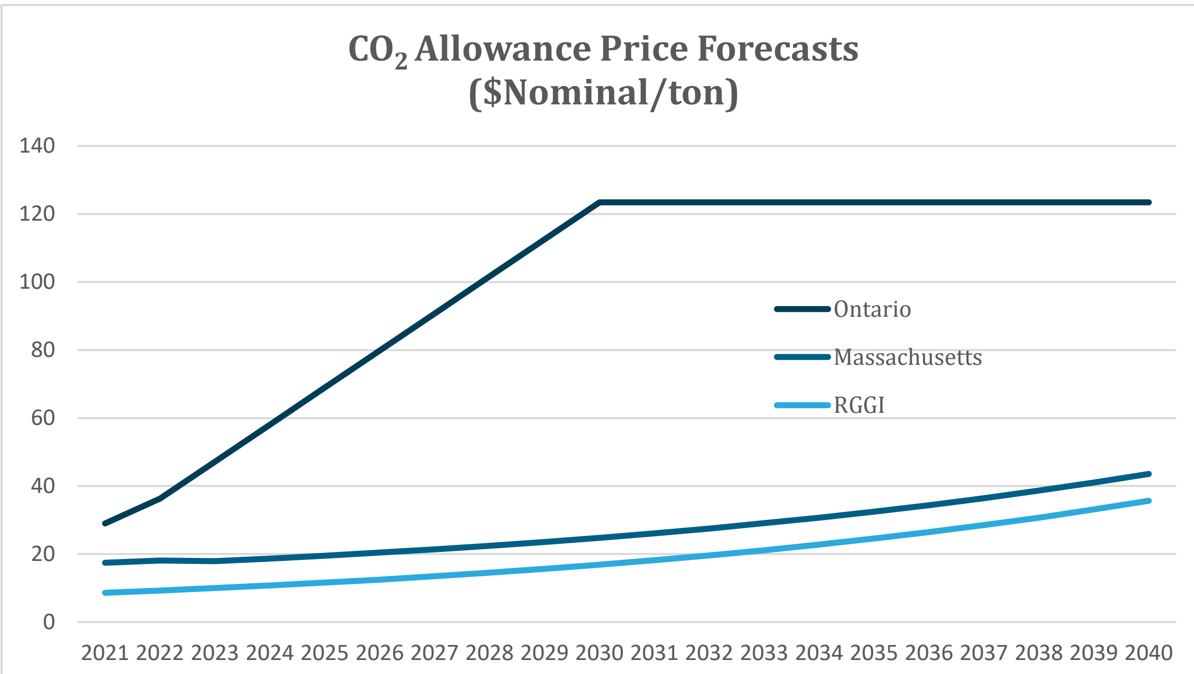
Massachusetts began implementing its own single state cap-and-trade program in 2018, which is similar to RGGI but with more restrictive caps applicable to generators located in Massachusetts.[13]

[13] https://www.mass.gov/guides/electricity-generator-emissions-limits-310-cmr-774

Massachusetts allowance prices assumed in this study are incremental to RGGI allowance prices imposed upon Massachusetts's emitting generators. The study also assumes a distinct CO_2 allowance price forecast applicable to IESO (Ontario) generation based upon CO_2 prices in *Canada's A Healthy Environment and a Healthy Economy*.[14]

Figure 17 below shows the CO_2 emission allowance price forecasts by year in $/ton

Figure 17: CO_2 Emission Allowance Price Forecast



E.1.6. External Area Model

ISO-NE, IESO, and PJM are actively modeled in the production cost simulation. The HQ system is not explicitly modeled since it is asynchronously tied to the New York bulk system. Proxy buses representing the direct ties from HQ to NYISO, HQ to IESO and HQ to ISO-NE are modeled. Figure 18 through Figure 20 list the additions, retirements and rerates for the external control areas by fuel source by year as reported by the external control areas in their respective planning documents. Figure 21 presents the aggregate capacities by unit type.

Figure 18: PJM Unit Additions and Retirements (MW)

[14] https://www.canada.ca/en/services/environment/weather/climatechange/climate-plan/climate-plan-overview/healthy-environment-healthy-economy.html

Year	Source	Additions	Retirements
2021	Coal		1,010
	Fossil Fuel	2,453	215
	Hydro		
	Landfill Gas/Bio		
	Nuclear		
	Solar	751	
	Wind	560	
2022	Coal		1,199
	Fossil Fuel	3,988	44
	Hydro		
	Landfill Gas/Bio		
	Nuclear		
	Solar	660	
	Wind		
2023	Coal		1,006
	Fossil Fuel	1,200	80
	Hydro		
	Landfill Gas/Bio		
	Nuclear		
	Solar		
	Wind		

Figure 19: IESO Unit Additions and Retirements (MW)

Year	Source	Additions	Retirements
2021	Coal		
	Fossil Fuel	224	
	Hydro		
	Landfill Gas/Bio		38
	Nuclear		
	Solar		
	Wind	100	
2022	Coal		
	Fossil Fuel		38
	Hydro		
	Landfill Gas/Bio		
	Nuclear		
	Solar		
	Wind		
2023	Coal		
	Fossil Fuel	896	
	Hydro		
	Landfill Gas/Bio		
	Nuclear		
	Solar		
	Wind		
2024	Coal		
	Fossil Fuel		
	Hydro		
	Landfill Gas/Bio		
	Nuclear		1,030
	Solar		
	Wind		
2025	Coal		
	Fossil Fuel	1,568	
	Hydro		
	Landfill Gas/Bio		
	Nuclear		2,064
	Solar		
	Wind		

Figure 20: ISO-NE Unit Additions and Retirements (MW)

Year	Source	Additions	Retirements
2021	Coal		383
	Fossil Fuel		
	Hydro		
	Landfill Gas/Bio		
	Nuclear		
	Solar	227	
	Wind		
2022	Coal		
	Fossil Fuel	679	662
	Hydro		
	Landfill Gas/Bio		
	Nuclear		
	Solar		
	Wind		
2023	Coal		
	Fossil Fuel		272
	Hydro		
	Landfill Gas/Bio		
	Nuclear		
	Solar	100	
	Wind		
2024	Coal		
	Fossil Fuel		1,607
	Hydro		
	Landfill Gas/Bio		8
	Nuclear		
	Solar		
	Wind		

Figure 21: Control Area Capacity Values

SUMMER CAP (MW)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
IESO	**35,646**	**35,650**	**36,732**	**36,732**	**37,228**	**35,164**	**35,164**	**35,206**	**35,206**	**35,206**
Combined Cycle	6,923	6,923	6,885	6,885	6,885	6,885	6,885	6,885	6,885	6,885
Combustion Turbine	716	716	1,836	1,836	3,404	3,404	3,404	3,404	3,404	3,404
Conventional Hydro	7,121	7,163	7,163	7,163	7,121	7,121	7,121	7,163	7,163	7,163
Other Steam Turbines	332	294	294	294	294	294	294	294	294	294
Pumped Storage Hydro	175	175	175	175	175	175	175	175	175	175
Solar	478	478	478	478	478	478	478	478	478	478
Steam Turbine (Nuclear)	12,959	12,959	12,959	12,959	11,929	9,865	9,865	9,865	9,865	9,865
Steam Turbine (Oil and Gas)	2,018	2,018	2,018	2,018	2,018	2,018	2,018	2,018	2,018	2,018
Wind	4,924	4,924	4,924	4,924	4,924	4,924	4,924	4,924	4,924	4,924
NYISO	**39,507**	**38,837**	**38,421**	**38,421**	**38,441**	**38,441**	**38,441**	**38,393**	**38,393**	**38,393**
Combined Cycle	11,206	11,206	11,206	11,206	11,206	11,206	11,206	11,206	11,206	11,206
Combustion Turbine	4,482	4,453	3,778	3,778	3,750	3,750	3,750	3,750	3,750	3,750
Conventional Hydro	4,489	4,441	4,441	4,441	4,489	4,489	4,489	4,441	4,441	4,441
Internal Combustion Engine	22	22	22	22	22	22	22	22	22	22
Landfill Gas	106	106	106	106	106	106	106	106	106	106
Other Steam Turbines	209	209	209	209	209	209	209	209	209	209
Pumped Storage Hydro	1,405	1,405	1,405	1,405	1,405	1,405	1,405	1,405	1,405	1,405
Solar	384	522	542	542	542	542	542	542	542	542
Steam Turbine (Nuclear)	4,378	3,342	3,342	3,342	3,342	3,342	3,342	3,342	3,342	3,342
Steam Turbine (Oil and Gas)	10,634	10,634	10,634	10,634	10,634	10,634	10,634	10,634	10,634	10,634
Wind	2,192	2,497	2,736	2,736	2,736	2,736	2,736	2,736	2,736	2,736
PJM	**202,357**	**205,746**	**205,703**	**204,617**	**204,652**	**204,652**	**204,652**	**204,617**	**204,617**	**204,617**
Combined Cycle	53,770	57,646	58,846	58,846	58,846	58,846	58,846	58,846	58,846	58,846
Combustion Turbine	29,655	29,655	29,611	29,531	29,531	29,531	29,531	29,531	29,531	29,531
Conventional Hydro	2,928	2,893	2,893	2,893	2,928	2,928	2,928	2,893	2,893	2,893
Internal Combustion Engine	683	683	683	683	683	683	683	683	683	683
Landfill Gas	521	521	521	521	521	521	521	521	521	521
Other Steam Turbines	3,338	3,338	3,338	3,338	3,338	3,338	3,338	3,338	3,338	3,338
Pumped Storage Hydro	5,182	5,182	5,182	5,182	5,182	5,182	5,182	5,182	5,182	5,182
Solar	4,265	4,925	4,925	4,925	4,925	4,925	4,925	4,925	4,925	4,925
Steam Turbine (Coal)	49,716	48,706	47,507	46,501	46,501	46,501	46,501	46,501	46,501	46,501
Steam Turbine (Nuclear)	33,418	33,418	33,418	33,418	33,418	33,418	33,418	33,418	33,418	33,418
Steam Turbine (Oil and Gas)	7,168	7,066	7,066	7,066	7,066	7,066	7,066	7,066	7,066	7,066
Wind	11,713	11,713	11,713	11,713	11,713	11,713	11,713	11,713	11,713	11,713
ISO-NE	**32,177**	**32,883**	**32,321**	**32,049**	**30,416**	**30,416**	**30,416**	**30,443**	**30,443**	**30,443**
Combined Cycle	13,988	14,512	14,449	14,449	13,012	13,012	13,012	13,012	13,012	13,012
Combustion Turbine	3,401	3,556	3,540	3,391	3,373	3,373	3,373	3,373	3,373	3,373
Conventional Hydro	1,961	1,988	1,988	1,988	1,961	1,961	1,961	1,988	1,988	1,988
Internal Combustion Engine	185	185	180	160	144	144	144	144	144	144
Landfill Gas	74	74	74	74	66	66	66	66	66	66
Other Steam Turbines	1,052	1,052	1,052	1,052	1,052	1,052	1,052	1,052	1,052	1,052
Pumped Storage Hydro	1,860	1,860	1,860	1,860	1,860	1,860	1,860	1,860	1,860	1,860
Solar	287	287	387	387	387	387	387	387	387	387
Steam Turbine (Nuclear)	3,380	3,380	3,380	3,380	3,380	3,380	3,380	3,380	3,380	3,380
Steam Turbine (Oil and Gas)	4,751	4,751	4,173	4,070	3,943	3,943	3,943	3,943	3,943	3,943
Wind	1,238	1,238	1,238	1,238	1,238	1,238	1,238	1,238	1,238	1,238
Grand Total	**309,687**	**313,116**	**313,177**	**311,819**	**310,737**	**308,673**	**308,673**	**308,659**	**308,659**	**308,659**

E.1.7. Hurdle Rates and Interchange Models

Hurdle rates set the conditions under which economic interchange occurs between neighboring markets/control areas in the model. They represent a minimum savings level that needs to be achieved before energy will transact across the interface. Hurdle rates help ensure that the production-cost simulation is reasonably consistent with the historical pattern of internal NYCA generation and imports. Hurdle rates are used to reflect actual inter-regional energy market transaction costs. A hurdle rate tuning process is used during the benchmarking stage of modelling to align the base model imports and exports with historic performance.

Two independent hurdle rates are used in The Outlook, one for the commitment of generation and a separate one for the dispatch of generation. Both commitment and dispatch hurdle rates are held constant throughout the 2021-2040 study period. The hurdle rate values produce results consistent with NYCA historic total import levels.

During the tuning process, the flow on the Cross Sound Cable (CSC) was modeled to allow up to 330 MW from ISO-NE to Long Island. The flow on the Linden VFT was modeled to allow up to 315 MW in both directions. The Neptune and HTP flows were modeled to allow up to 660 MW of flow from PJM into Long Island and New York City, respectively.

The hourly interchange flow for each interface connecting the NYISO with neighboring control areas was priced at the LBMP of its corresponding proxy bus for purposes of calculating the import and export cost component of NYCA Wide production cost. The summation of all 8,760 hours determined the annual cost of the energy for each interface. Figure 22 lists the proxy bus location for each interface.

Figure 22: Interchange LBMP Proxy Bus Area

Interface	Proxy Bus
PJM	Keystone
Ontario	Bruce
Quebec	Chateauguay and Cedars
Neptune	Raritan River
New England	Sandy Pd
Cross Sound Cable	New Haven Harbor
HTP	Bergen
VFT	Linden 138 kV
Northport Norwalk Cable	Norwalk Harbor

E.1.8. Production Cost Model

Production cost models require input data to develop cost curves for the resources that the model will commit and dispatch to serve the load, subject to the constraints given in the model. This section discusses how production cost input data is developed. The incremental cost of generation is the product of the incremental heat rate multiplied by the sum of fuel cost, emissions cost, and variable operation and maintenance expenses.

Heat Rates

Fuel costs typically represent the largest variable expense for fossil fuel-fired generating units. Cost curves are the product of fuel prices and incremental heat rates. Individual unit heat rates are commercially sensitive confidential information and thus are not widely available from generator owners.

Unit heat rate input data is based on the U.S. Environmental Protection Agency's (EPA) Clean Air Market Data[15] and, where available, unit production data from the U.S. Energy Information Administration (EIA).

Outlook simulation models employ power points which represent minimum, intermediate, and maximum power production levels where generating units can be simulated to operate on a sustained basis. Each power point is tied to a point on the heat rate curve allowing incremental heat rates to be determined for each unit. The power points and incremental heat rates are developed on a Summer/Winter Capability Period basis and differentiate between fuels where applicable.

Fuel Switching

Fuel switching capability is widespread within the NYCA. According to data from the 2021 Gold Book[16], 50% of the 2021 generating capacity in the NYCA – 19,315 MW of generation – has the ability to burn either oil or gas. For such units, the production-cost simulation model selects the economic fuel based on weekly production costs for units with dual-fuel capability.

The New York State Reliability Council (NYSRC) establishes rules for the reliable operation of the New York Bulk Power System. Two of those rules guard against the loss of electric load because of the loss of gas supply. The loss of a gas facility may lead to the loss of some generating units. This loss becomes critical because it may result in voltage collapse when load levels are high enough. Therefore, criteria are established whereby certain units that are capable of doing so are required to switch to minimum oil burn levels so that in the event of the worst single gas system contingency these units stay on-line at minimum generation levels and support system voltage.

Rule I-R3 states that "The New York State bulk power system shall be operated so that the loss of a single gas facility does not result in the loss of electric load within the New York City zone." Rule I-R5 similarly states "The New York State bulk power system shall be operated so that the loss of a single gas facility will not result in the uncontrolled loss of electricity within the Long Island zone."

To satisfy the I-R3 and I-R5 criteria, annual studies are performed by the TOs that update the configurations of the electricity and gas systems and simulate the loss of critical gas supply facilities.

Some new combined cycle gas turbine units in the New York City and Long Island Zones have the ability to "auto-swap" from gas-burn to oil-burn with a limited loss of output that can be quickly recovered. As the generator fleets in these zones have experienced a shift to increased use of combined cycle units with auto-swap capability, the amount of oil used in steam units to satisfy minimum oil burn

[15] https://ampd.epa.gov/ampd/

[16] Taken from Table V-2a https://www.nyiso.com/documents/20142/2226333/2021-Gold-Book-Final-Public.pdf/

criteria has decreased.

Minimum oil burn rules have not been explicitly modeled in the production cost simulations for The Outlook. Minimum oil burn units are committed and dispatched in the NYISO markets using the cost of the most economic fuel. Any cost incurred from firing oil when it is not economic to do so is recovered outside the market. Consequently, the minimum oil burn program does not affect LBMPs or any derivative metric (Demand Congestion, Load, Payment, *etc*.) and is more appropriately accounted for outside the GE-MAPS simulation.

Generation Maintenance

NYCA generation maintenance modeling was updated for The Outlook utilizing the latest planned and random outage rates from the 2021-2030 CRP process. External control areas (IESO, ISO-NE, and PJM) generation planned and forced outage were developed using NERC class average outage data.

Hourly Resource Modifiers (HRMs)

Several types of generation technologies, such as non-pondage hydro, wind, and solar were represented using MAPS hourly modifier models. This approach uses a fixed 8,760 hourly input schedule that represents the hourly generation dispatch for each unit. The shape applied to the HRM inputs for each generator type is based on historical data. Capacity and energy capabilities are adjusted for individual generator parameters.

Hourly modifier output matches the input schedule with the one exception of energy curtailment, mostly due to transmission constraints. In MAPS, curtailment occurs when the LBMP at a generator node drops below the modeled dispatch cost of the hourly modifier, which is an indication of local transmission congestion caused by renewable generation injection. The amount of energy curtailed represents the amount necessary to limit LBMP at or above the dispatch cost of the generator, to the extent that a generator has energy to curtail.

The dispatch costs modeled for hydro, wind, and solar in The Outlook database were based on historical observations and published Renewable Energy Certificates ("REC") values where available. The dispatch cost determines the curtailment order of resources in the event of a tie. Units with higher REC prices modeled will be curtailed after units with lower REC prices at the same location.

Generally, as hydro, wind, and solar units are not co-located they experience different nodal LBMP impacts of transmission congestion and losses. In the analyses performed in The Outlook, a majority of the curtailments observed were a direct result of local transmission congestion.

Hydro Model

Hydro units in the GE-MAPS production cost model leverage the internal pondage logic, which assumes pondage capability even though not all hydro units in New York are capable. The pondage model schedules resources using a fixed monthly energy targets based on historical operation. The software optimizes hydro operation to minimize production cost of the entire system and meet the monthly energy targets for each unit. In doing so, the pondage capability of some units, such as run-of-the-river hydro, may be overestimated as the software can re-distribute unused energy to other hours within a month when available. This way of scheduling hydro resources to operate in a flexible manner may not reflect actual operation of units that have limited pondage capability, and thus would likely under report the amount of curtailed energy from such resources.

Additionally, Zone D imports from the hydro dominant HQ region leverage the GE-MAPS fixed-injection model, which has no flexibility in scheduling. Hydro generation electrically close to the HQ imports in Zone D, such as St. Lawrence Hydro (a run-of-the-river hydro modeled as pondage,) will compete to deliver energy to the network. Depending on the dispatch cost of Zone D HQ imports and the nearby hydro, considering transmission constraints, it's likely that curtailed energy is biased towards the fixed-injection model over the pondage model. This model interaction will be evaluated further in future Outlook studies.

Appendix E.2: Contract Case

The principle change in the Contract Case is the inclusion of REC contracted generators through the 2020 NYSERDA REC Solicitation.[17] Figure 23 and Figure 24 break out the nearly 9,500 MW of renewable capacity additions included in the Contract Case that were not modeled in the Baseline Case by online year and zone.[18] Some projects with state contracts are in-service or advanced in development and therefore already included in the Baseline Case either as existing or as new if they have met the inclusion rules.

[17] https://www.nyserda.ny.gov/All-Programs/Clean-Energy-Standard/Renewable-Generators-and-Developers/RES-Tier-One-Eligibility/Solicitations-for-Long-term-Contracts/2020-Solicitation-Resources#

[18] https://www.nyiso.com/documents/20142/26278859/System_Resource_Outlook-Contract_Case_Renewables.xlsx

Figure 23: Contract Case Renewable Capacity Additions by Online Year

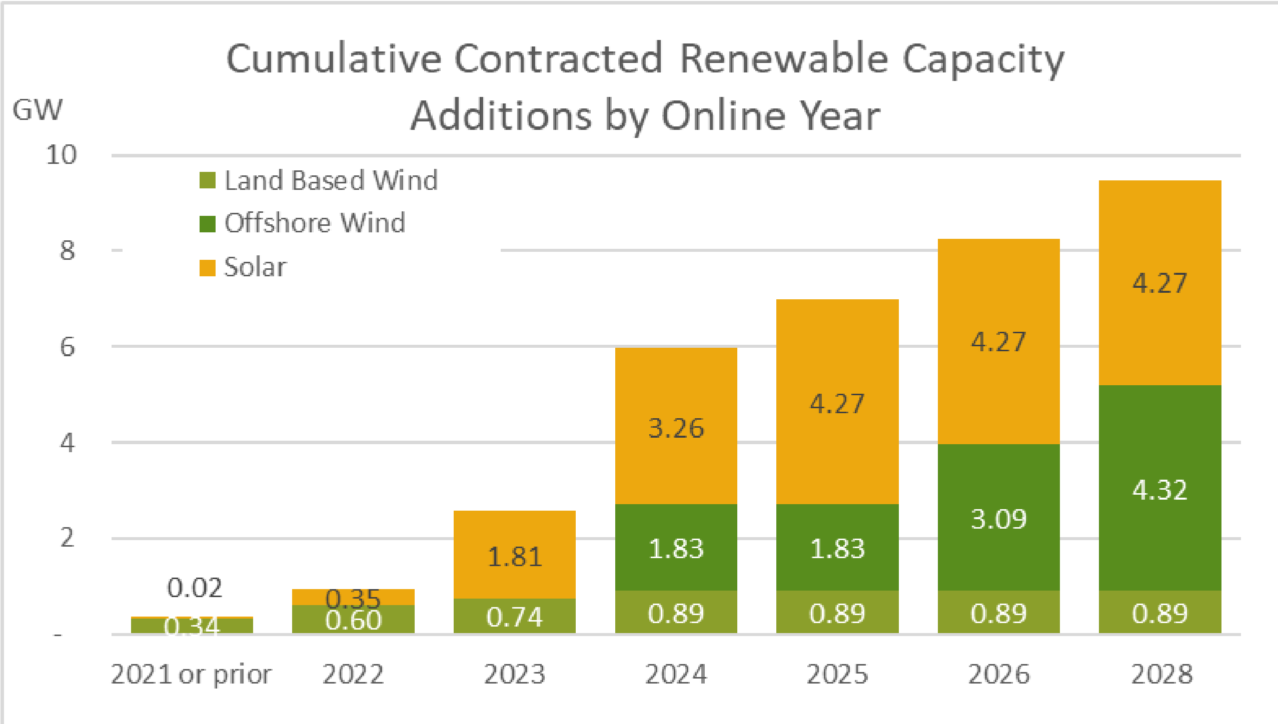
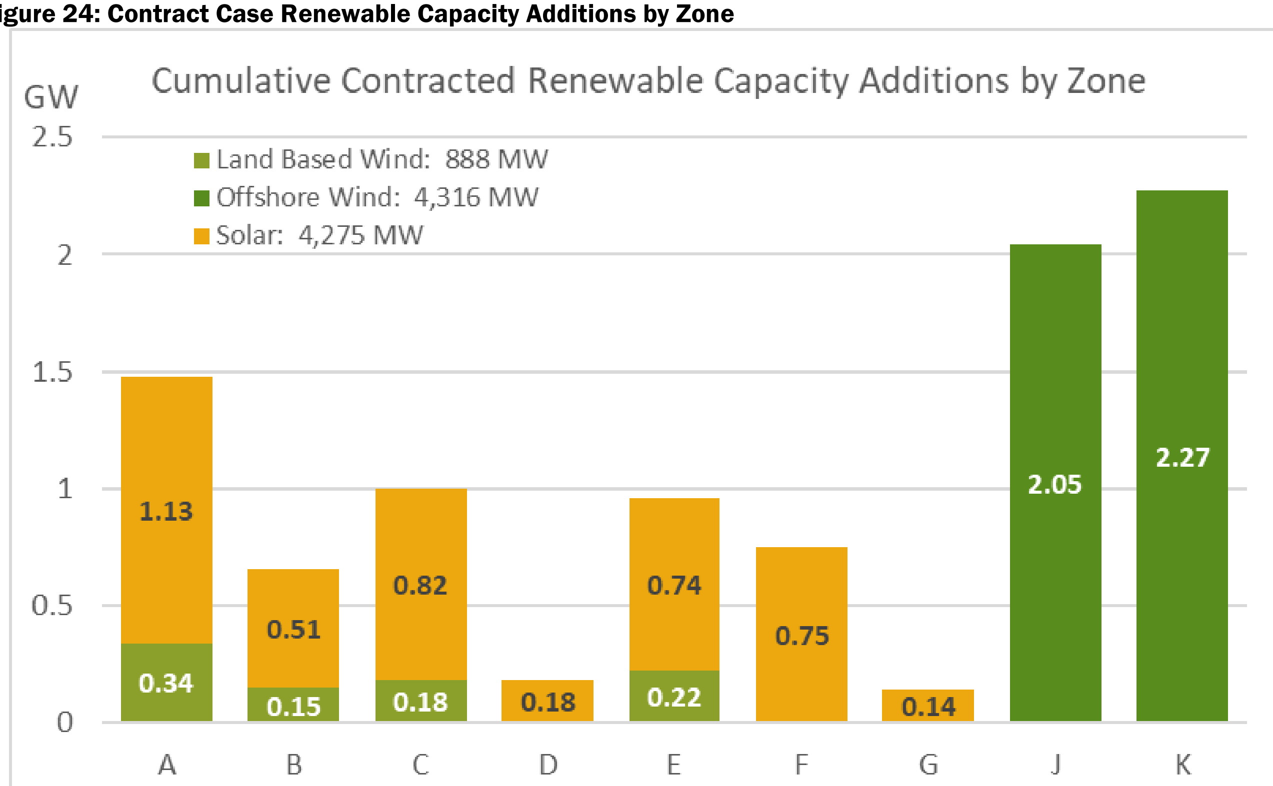


Figure 24: Contract Case Renewable Capacity Additions by Zone



E.2.1. REC Pricing

As noted above, the dispatch costs are based on REC prices received by the project. REC prices for each project[19] are modeled as a negative bid adder in the production cost model to represent the impact from out-of-market payments. This price sets the priority order for economic dispatch and curtailment of resources due to transmission congestion.

The aggregate premium of Index REC Strike price to Fixed RECs is used as a proxy to calculate a representative negative bid adder for Index RECs. Assumed prices were developed to compare fixed and indexed RECs on the same basis and to preserve project-to-project price variations.[20] Each individual project's price is modeled as fixed or indexed as shown below. Given that index RECs are difficult to model in production cost simulations, the following bid values were used for fixed and index REC prices:

Modeled Fixed REC bid = - REC price

Modeled Indexed REC bid = - (Index Strike Price – Average Index Premium)

For each generator with Index RECs, the bids are offset by the average index premium by generator type. For example, if the average wind fixed REC is $21, the average wind index REC is $55, and hypothetical Wind Plant X's index REC is $60, modeled REC bid = -($60-($55-$21)) = -$26.

The specific REC bidding prices used for each generation type can be found in Appendix C: Production Cost Assumptions Matrix.

E.2.2. Round-Trip Analysis

The NYISO leverages a "round-trip" modelling technique to capture changes in transmission congestion patterns as new generation is added to the model. The technique integrates the MAPS production cost model, PSS/E powerflow model, and a TARA transfer analysis model to correctly identify new contingencies relevant to the system configuration being modelled. Production cost models use a static list of contingency pairs whereby the "round-trip" technique makes the contingency list dynamic.

[19] https://www.nyiso.com/documents/20142/26278859/System_Resource_Outlook-Contract_Case_Renewables.xlsx

[20] https://www.nyiso.com/documents/20142/27945979/04_System_Resource_Outlook.pdf

Figure 25: Roundtrip MAPS/TARA Analysis

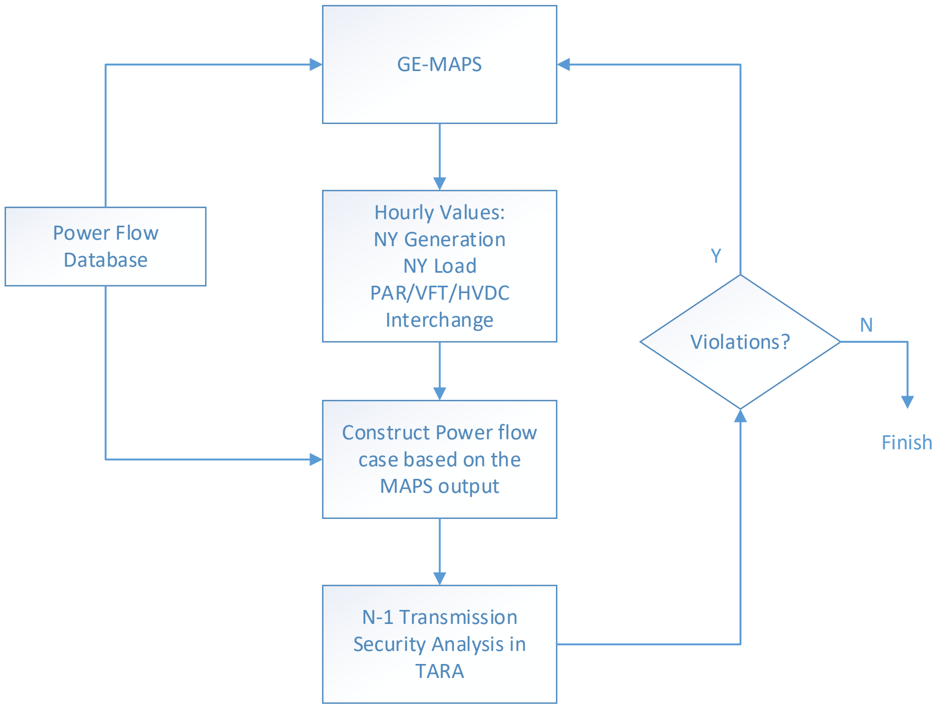


Figure 25 shows the flowchart for Roundtrip MAPS/TARA Analysis. This iterative analysis has three steps:

1. Start with the MAPS production cost run with constraints modeled in the Baseline Case. The resulting hourly MAPS output is utilized to construct power flow cases for each four-hour interval in a year (2,190 powerflow cases for one year) and solve each powerflow case in PSS/E using information including hourly NYCA zonal loads, hourly NYCA generation dispatches, hourly NYCA PAR schedules, and hourly NYCA interchange tie line flows.
2. Perform N-1 transmission security analysis on all created cases in TARA while monitoring NYCA facilities 115 kV and above, taking into account all bulk transmission system contingencies as well as local transmission system contingencies. Standard NYISO planning contingencies and additional TO contingencies are included in the TARA analysis. TO contingencies include those from the latest transmission planning studies, any additional project specific contingencies, and any contingencies requested by TOs.
3. Multiple iterations of N-1 transmission security analysis are run to ensure that consistent monitored facility/contingency pairs are observed in each iteration. Monitored facility/contingency pairs with the highest overloads are included in the production cost database.
4. Add the reported monitored facility and contingency pairs from TARA analysis into the existing

production cost database. Secure the expanded list of monitor facilities and contingency pairs in the successive runs.

Appendix E.3: Policy Case

In addition to the assumptions in the Contract Case for this study, the Policy Case includes additional assumptions specific to accommodating state policies, including the CLCPA targets, updated load forecasts and shapes, and contracted NYSERDA Tier 4 HVDC transmission projects. For use in the 2021-2040 Outlook's Policy Case, a capacity expansion model was developed using PLEXOS software to simulate generation expansion and retirements to study achievement of these state policy mandates. The capacity expansion model incorporates assumptions from the Baseline and Contract Case databases as a starting point and includes additional assumptions as applicable in the Policy Case to simulate optimal generation capacity mix over the study period.

In this inaugural Outlook study, the capacity expansion model was developed, tested, and validated through the NYISO stakeholder process. Through scenarios, various assumption changes were examined to assess their impact on the capacity expansion model results. Ultimately, two of the capacity expansion scenarios were selected to represent capacity expansion cases for the detailed nodal production cost model for further analysis; these cases will be referred to as Scenario 1 ("S1") and Scenario 2 ("S2") for purposes of this report.

Owing to the uncertainty of the pathway to the future system in the Policy Case, simulations for the capacity expansion and production cost models are limited to five-year increments within the study period (*i.e.*, 2025, 2030, 2035, and 2040 study years).

E.3.1. Capacity Expansion Modeling

Capacity Expansion Key Assumptions

As noted above, two capacity expansion scenarios, Scenario 1 ("S1") and Scenario 2 ("S2"), were selected to run through production cost simulation for this Outlook. The assumptions outlined in this section further describe these two capacity expansion cases and how they differ.

Based on the assumptions for the capacity expansion model, the model provides a projection of how the resource mix could evolve. The capacity expansion results in this study are not an endorsement of outcomes under any specific set of assumptions; rather, results are intended to inform future NYISO studies and stakeholders of potential generation buildouts under a multitude of scenarios.

The capacity expansion model is limited to the NYCA system only; it does not include neighboring regions, beyond imports of qualifying renewable hydropower from Hydro Quebec. This limitation extends to generation as well as transmission in neighboring regions. It is noteworthy because with the system represented in the capacity expansion model limited to the NYCA, the installed capacity and generation mix assumed to satisfy the CLCPA targets is limited to the NYCA as well. In other words, the capacity expansion model does not assume imports or exports, except that the contributions from Tier 4 projects are included as soon as the projects are assumed to be in-service in addition to the existing imports from Hydro Quebec. Additional detail on the specific policy constraints modeled as well as the transmission/system representation for the capacity expansion model are included in the following sections.

To maintain reasonable compute times, a set of time blocks was defined for the capacity expansion model to represent the hourly data for each year. These blocks are grouped by season and hour of the day to capture the seasonal and diurnal variations in system conditions. Additional details on the time block methodology used in the capacity expansion model are included in the model horizon and chronological representation section.

Load and Capacity Forecasts

To capture a range of future potential load conditions, two different load forecasts were assumed for the capacity expansion scenarios selected in this Outlook study.[21]

Assumptions Specific to S1

The load forecast used in the capacity expansion model S1 was based on the NYISO's 2019 Climate Change Phase I study. Following the publication of the Climate Change Phase I study, an incremental four GW additional BTM-PV CLCPA target for 2030 was recommended by DPS, and subsequently included in the load forecast for use in the Policy Case. For purposes of the Policy Case, the annual electrification forecasts between model years 2030 and 2040 were modified to smooth out the growth of electrification through 2040, while maintaining the original electrification forecasts for 2040. The Scenario 1 load forecast includes the following modifications:

- **10 GW BTM-PV by 2030 CLCPA target** - since the publication of the Climate Change Phase I study, the additional BTM-PV CLCPA target for 2030 was approved by the PSC[22], and subsequently included in the load forecast for use in this Outlook's Policy Case,
- **Removal of impact from energy storage resources** - the impact of energy storage resources was removed from the original forecast because energy storage resources are modeled explicitly in the capacity expansion model, and

[21] https://www.nyiso.com/documents/20142/31279228/07_System_Resource_Outlook_Hourly_Load_Forecasts_Final.xlsx/

[22] https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={498EE5D6-6211-4721-BA98-AF40EF3F620C}

- **Smoothed annual electrification forecasts** - the annual electrification forecasts between model years 2030 and 2040 were modified to smooth out the growth of electrification through 2040, while maintaining the original electrification forecasts for 2040.

Assumptions Specific to S2

The load forecast used in S2 was based on the Climate Action Council Draft Scoping Plan Strategic Use of Low Carbon Fuels Scenario ("Scenario 2")[23] with:

- no electrolysis loads (*i.e.*, hydrogen production), and
- "No End Use Flexibility."

Figure 26 includes annual energy (GWh) and peak (MW) forecasts assumed for scenarios S1 and S2. Comparatively, S2 assumes higher annual energy forecasts and lower seasonal peak forecasts than S1.

Figure 26: Policy Case Annual Load and Seasonal Peak Forecasts

Annual Energy Forecasts - GWh

Year	S1	S2
2025	144,704	150,047
2030	150,909	164,256
2035	172,566	204,702
2040	208,679	235,731

Summer Peak Forecasts - MW

Year	S1	S2
2025	31,679	29,612
2030	34,416	30,070
2035	40,033	34,402
2040	48,253	38,332

Winter Peak Forecasts - MW

Year	S1	S2
2025	26,491	21,758
2030	31,717	25,892
2035	41,681	35,093
2040	57,144	42,301

Generation

Existing generation, as well as planned generation builds and scheduled generation retirements, assumed in the capacity expansion model for the Policy Case are based on the Contract Case database. S1 did not assume any age-based retirements for fossil fuel-fired generators. S2 assumes that additional firm fossil fuel-fired generator retirements occur based on age, at: 62 years for steam turbines and 47 years for

[23] https://climate.ny.gov/-/media/Project/Climate/Files/IA-Tech-Supplement-Annex-2-Key-Drivers-Outputs.xlsx

combustion turbines.[24] It was assumed that no combined cycle units retire based on age for this scenario. Incremental age-based retirements captured in Scenario 2 include approximately 12 GW, nearly half the initial 26 GW fossil fleet.

The capacity expansion model allows for retirement of existing generators throughout the model's horizon. Generator retirements are enabled such that individual generators could retire any year within the study period. The capacity expansion model considers each generator's fixed and variable operating and maintenance costs over the entire model horizon when determining whether to retire the generator each year of the study period. The capacity expansion model co-optimizes generation capital and production costs to determine a least cost future generation mix.

Generator expansion is enabled at the zonal level, such that one representative generator per type is allowed for each applicable NYCA zone. The capacity expansion model assumes linear expansion[25] for the new generators, such that the candidate generator can increase its capacity each year up to its maximum capacity (MW) limitation, if imposed[26], noting that a single generator would be built per zone. The generator builds assumed from the capacity expansion model are then translated into discrete generators in the production cost modeling for the Policy Case. Additional detail on the process of generator placement between capacity expansion and production cost modeling is included in Appendix Production Cost SimulationE.3.2. The capacity expansion model allows for generation expansion of the following generator types:

- Offshore wind (OSW)
- Land based wind (LBW)
- Utility PV (UPV)
- 4-hour battery storage
- Dispatchable Emission Free Resource (DEFR)

Generation expansion in the capacity expansion model is limited to renewable generation, battery storage, and DEFR generators to provide insight into the potential resource mix to comply with state policies. Of note, fossil fuel-fired generation, nuclear, BTM-PV, and hydro generation were not candidate generator types eligible for generation expansion in this Outlook study. The characteristics and

[24] https://climate.ny.gov/-/media/Project/Climate/Files/Draft-Scopping-Plan-Appendix-D.pdf

[25] Linear expansion allows for partial unit retirements and generation additions by 1 MW increments in order to reduce computational complexity.

[26] Zonal capacity limitations are assumed for candidate LBW, OSW, and UPV generators and are based on the 2040 limitations for the applicable generator type, per https://climate.ny.gov/-/media/Project/Climate/Files/IA-Tech-Supplement-Annex-1-Input-Assumptions.ashx, excluding LBW in S2. For LBW in S2, the maximum allowable capacities for model years 2021-2030 are based on the 2030 limitations for LBW and model years 2031-2040 are based on the 2040 limitations.

capabilities of existing technologies (*i.e.*, renewables and battery storage) cannot solve for the 2040 zero emissions CLCPA target without significant capacity additions above and beyond the capacity requirements. Therefore, DEFR generation options were included in the capacity expansion model.

Given the significant uncertainty regarding potential technology options to serve future system needs flexibly with zero emissions, a range of capital and operating costs informed by prior studies[27] [28] were assumed for the DEFR generators. The DEFR generators represent a commercially unavailable future technology that would be dispatchable and that would produce emissions-free energy (*e.g.*, hydrogen, RNG, nuclear, or other long-term seasonal storage). For this Outlook study, three cost options were allowed as DEFR generators eligible for generation expansion.[29] These options reflect the following cost ranges[30]:

- HcLo - High capital cost with low operating (fuel and variable O&M) cost
- McMo - Medium capital cost with medium operating (fuel and variable O&M) cost
- LcHo - Low capital cost with high operating (fuel and variable O&M) cost

S1 assumed all three DEFR options as candidates for generation expansion while S2 assumed only the Medium Capital/Medium Operating cost option. As observed through results of scenario testing, which is described in further detail in Appendix G: Detailed Policy Case Capacity Expansion Scenarios, each of the DEFR options exhibits a different installed capacity and generation mix in the capacity expansion model. The DEFR options in S2 were limited to the Medium Capital/Medium Operating cost option only to produce a different operational profile for DEFRs between the two scenarios for further consideration in production cost analyses.

In the capacity expansion model, battery storage is modeled similar to candidate expansion generators, except that they are modeled in the Battery category in PLEXOS, which includes additional attributes (*e.g.*, state of charge, charge and discharge efficiencies, MWh capability).

Each generator is modeled as having technology specific attributes which help satisfy load and/or capacity contributions towards the resource adequacy constraints, as applicable to the technology type. Existing generators assumptions align with historic data (*e.g.*, max capability, monthly energy output, etc.).

[27] https://www.nyiso.com/documents/20142/13245925/Brattle%20New%20York%20Electric%20Grid%20Evolution%20Study%20-%20June%202020.pdf/

[28] https://www.nyserda.ny.gov/-/media/Files/EDPPP/Energy-Prices/Energy-Statistics/2020-06-24-NYS-Decarbonization-Pathways-Report.pdf

[29] A range of capital and operating costs for DEFRs were examined as part of this Outlook through scenarios. Additional details on these scenario assumptions are included in the following section.

[30] The range of DEFR costs evaluated in this Outlook, as well as approximations from other studies, are included in slides 13 & 14 of the December 17, 2021 ESPWG presentation. https://www.nyiso.com/documents/20142/27019028/ESPWG_System_Resource_Outlook_Update2.pdf/

The candidate expansion generators assume cost and technological capabilities consistent with the 2021 EIA Energy Outlook[31].

Intermittent generation resources (*e.g.*, LBW, OSW, UPV) use simulated hourly NREL profiles as an approximation of the energy output from each respective technology type[32]. Additionally, existing NYCA hydro generation uses monthly historic profiles at the generator level as an approximation of their energy contribution; hydro generation associated with qualifying imports from Hydro Quebec use hourly historic profiles to represent their energy contribution. Fossil fuel-fired generation, nuclear, and other qualified generators are modeled as dispatchable generation, consistent with their capabilities.

Additionally, generators in the capacity expansion model are assumed to have a capacity contribution towards satisfying the state's resource adequacy requirements. In addition to having an installed capacity (ICAP), each generator has an associated unforced capacity (UCAP) that ranges between 0%-100% of its installed capacity rating. The UCAP associated with each generator's contributes towards the Installed Reserve Margin (IRM) and/or Locational Capacity Requirements (LCRs), as applicable to the generator's location within the NYCA. Additional information on the IRM and LCR requirements, as modeled in the capacity expansion model, is included in the Resource Adequacy Constraints section of this Appendix.

The UCAP ratings for existing generators are based on the generators' historic performance or availability, as applicable to the generator type's UCAP rating methodology consistent with NYISO market rules. The UCAP ratings for candidate renewable generators (UPV, LBW, and OSW) and battery storage resources are modeled using declining capacity value curves related to the amount of each technology added to the system[33]. The UCAP ratings for candidate DEFR generators are consistent with the default derating factor value from the NERC GADS database for existing combined cycle generators.

Figure 27 represent the declining capacity value curves as a function of each technology type's installed capacity. The curves labeled as the generator type and "Outlook" designation represent the capacity value curves implemented in this Outlook study. The dotted curves used in this study are simplified representations of the curves that were implemented in the *"New York's Evolution to a Zero*

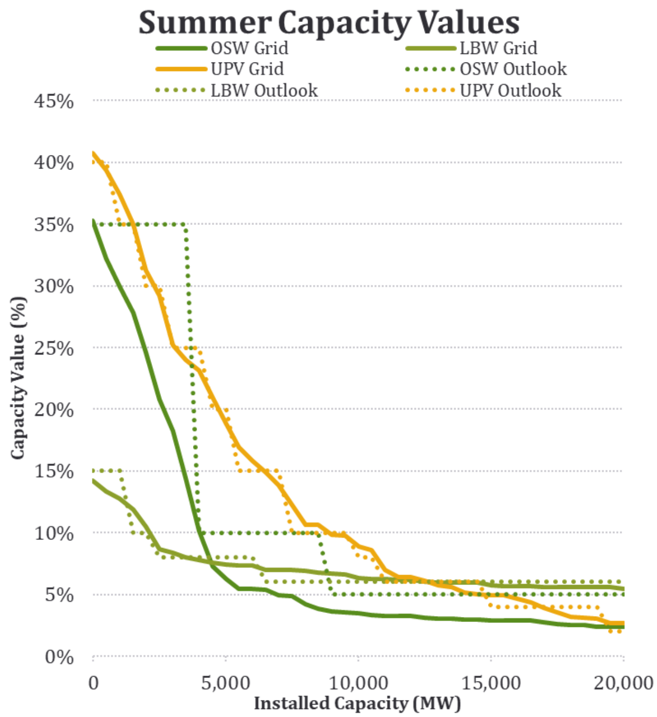
[31] https://www.eia.gov/outlooks/archive/aeo21/assumptions/pdf/electricity.pdf

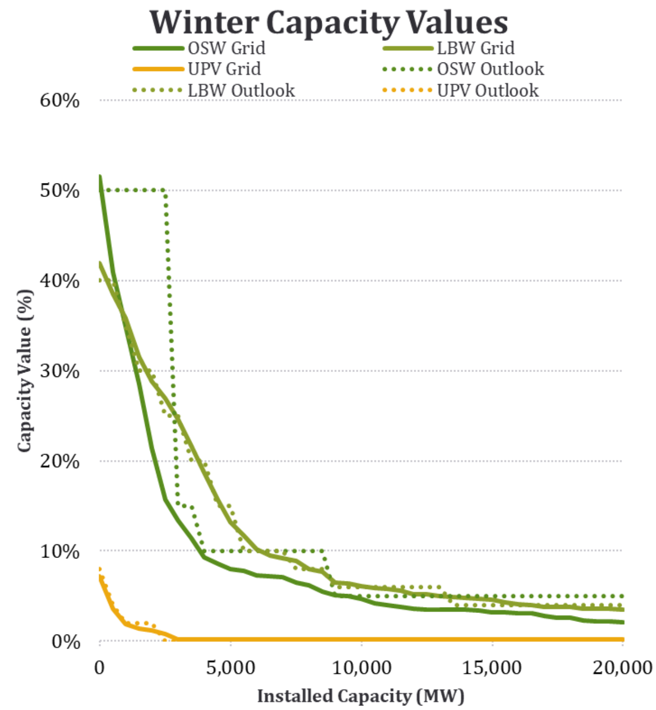
[32] The hourly shapes for existing LBW generators are based on historic data at the generator/county level and the shapes for new LBW generators (candidates for generation expansion) are based on NREL simulated data at the zonal level. The hourly shapes for existing UPV generators are based on historic data, UPV generators included in Contract Case are based on shapes specific to each proposed project, and UPV candidates for generation expansion are based on zonal NREL data. The hourly shapes for OSW generators are based on NREL data; contracted projects are based on clustered site level data and candidates for generation expansion are based on zonal data.

[33] https://www.nyiso.com/documents/20142/13245925/Brattle%20New%20York%20Electric%20Grid%20Evolution%20Study%20-%20June%202020.pdf/

Emission Power System" "Grid in Evolution Study," which are shown as solid lines in the figure.[34]

Figure 27: Policy Case Declining Seasonal Capacity Values





Transmission representation

The transmission model used in the capacity expansion model is based on the NYCA transmission network in the Policy Case; it does not include neighboring regions, including ties to NYCA neighbors, beyond imports (of qualifying renewable hydropower) from Hydro Quebec and limited ties to PJM between Zones A and C. The capacity expansion model starts with the complete nodal database from the production cost model, as applicable to the Policy Case. The PLEXOS model performs a nodal to zonal reduction of this database to create a pipe-and-bubble equivalent model of the NYCA region for the capacity expansion model. In this reduction, intra-zonal lines are collapsed.

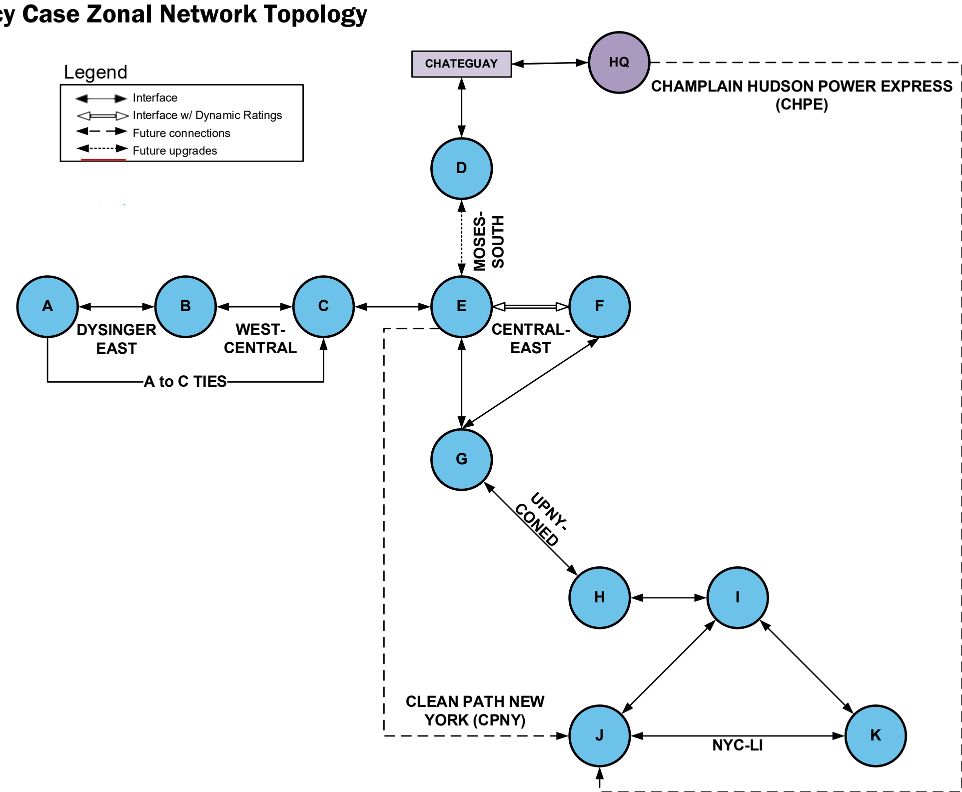
Of note, the Policy Case assumes three new transmission projects included as firm projects, incremental to what is included in the Baseline and Contract Cases. Planned additions to the New York transmission system assumed in the Policy Case include:

[34] https://www.nyiso.com/documents/20142/13245925/Brattle%20New%20York%20Electric%20Grid%20Evolution%20Study%20-%20June%202020.pdf/ (Slide 111)

- **December 2025:** NYPA Northern New York Priority Transmission Project, the NYPA "Smart Path", modeled as a 1,000 MW upgrade to the Moses-South interface;
- **December 2025:** Champlain Hudson Power Express (CHPE), modeled as 1,250 MW additional imports from Hydro Quebec into Zone J; and
- **June 2027:** Clean Path New York (CPNY), modeled as 1,300 MW, connecting Zone E and Zone J.

The capacity expansion model does not allow for transmission expansion as a modeling option in this Outlook study. The pipe-and-bubble equivalent model used in the capacity expansion model is included in Figure 28 below.

Figure 28: Policy Case Zonal Network Topology



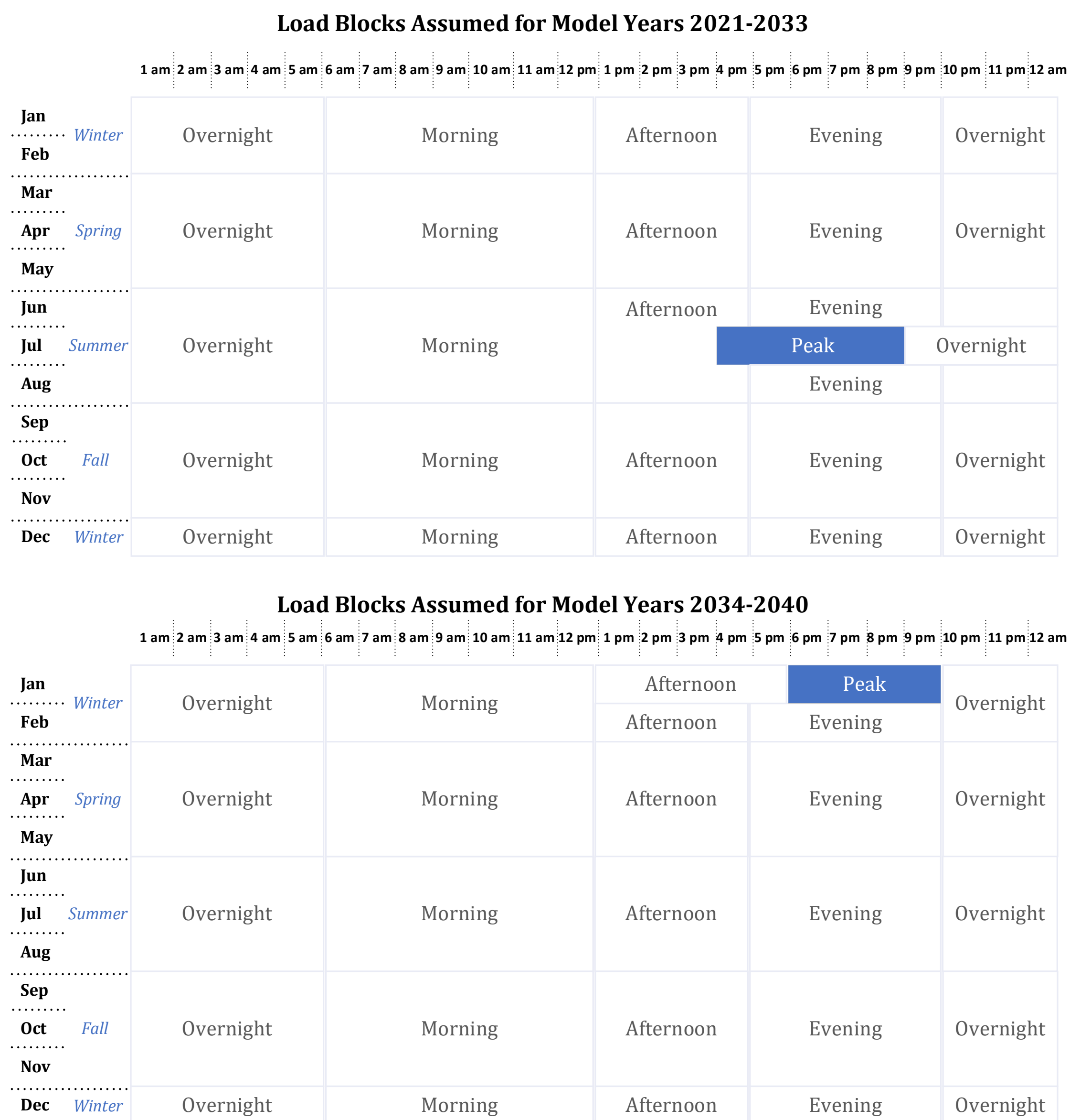
Model horizon and chronological representation

As referenced above, each year in the capacity expansion model is represented by 17 load blocks. This simplifying assumption on the model's chronology maintains a balance of computational time and a reasonable approximation of the seasonal and diurnal variations from the hourly input from the Policy Case's database.

For each year, 16 of the load blocks are represented by grouping hours of the year by season (Spring, Summer, Fall, and Winter) and time of the day (overnight, morning, afternoon, and evening) to capture the seasonal and diurnal variations in wind, solar, and load profiles. The 17th load block per year represents a period of peak load hours. The peak load block is assumed to occur in the summer for model years 2021-2033 and in the winter for model years 2034-2040, consistent with peak shifting in the load forecast from summer to winter around the year 2033.

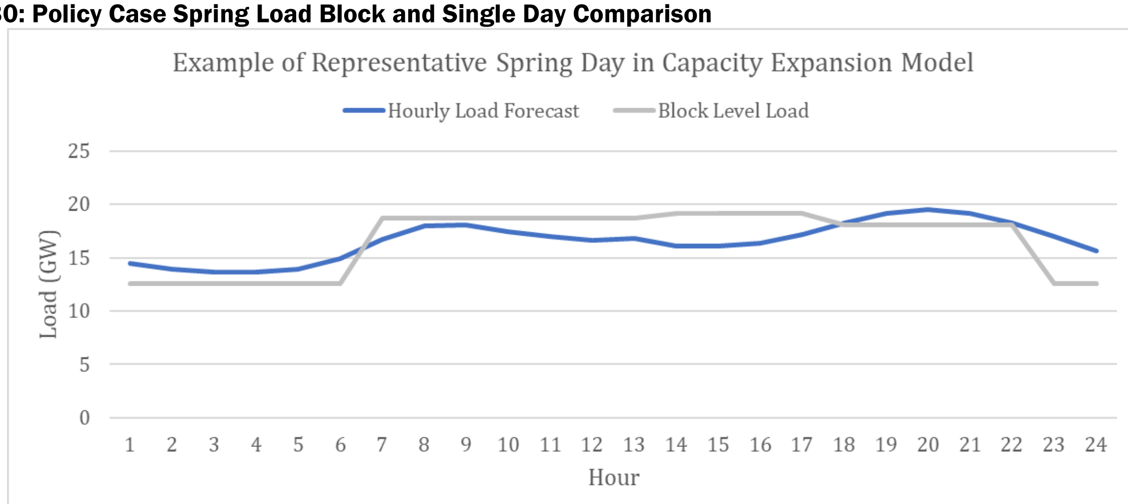
Figure 29 displays the load blocks assumed in the capacity expansion model by season and time of day. The load blocks used for model years 2021-2033 are represented in the top panel, those used for model years 2034-2040 are represented in the lower panel.

Figure 29: Policy Case Load Block Definitions



PLEXOS performs a conversion of the hourly, monthly, and seasonal input assumptions from the Policy Case database by a weighted average into the input assumptions for each block represented in the capacity expansion model. In other words, the underlying hourly data included in each load block are averaged to develop the representative load blocks for each year in the model's horizon. The duration of each load block is accounted for such that each representative block is a weighted average of the underlying hourly data embedded in that time period. For example, the underlying hourly data included in each "spring afternoon" load block (HB 14 through HB 17 for March, April, and May) are averaged to develop the representative load block for "spring afternoon" for each model year. Figure 30 represents an example of how the PLEXOS model averages the input hourly load data for each of the four predefined "spring" load blocks (overnight, morning, afternoon, and evening) to create a representative load for the "spring" season for a given year, as shown in grey. The blue line displays the hourly load profile for a single spring day.

Figure 30: Policy Case Spring Load Block and Single Day Comparison



Targeted Policy Attainment

For purposes of the Policy Case, the CLCPA targets and other state policy goals are modeled in the capacity expansion model as constraints, such that the generation and capacity mix must satisfy each respective constraint. The capacity expansion model considers existing generation as well as candidate expansion generators to satisfy these constraints. The policy-based constraints modeled in the capacity expansion model for this Outlook study focuses on the electric power sector and includes:

- 6 GW BTM-PV installed by 2025 (included in the load forecast)
- 3 GW energy storage installed by 2030
- 10 GW BTM-PV installed by 2030 (included in the load forecast)

- 70% renewable generation by 2030 (70 x 30)
- 9 GW offshore wind installed by 2035
- 100% emission free generation by 2040

The policy constraints specific to installed capacity of a certain generator type, for example the energy storage and offshore wind capacity targets, can only be satisfied by each respective generator type. The policy constraints specific to generation can be satisfied by the qualifying generator types, as applicable to each constraint. For example, the 70 x 30 constraint must be satisfied by generation from LBW, OSW, UPV, BTM-PV, hydro generation, and HQ imports. For comparison, the zero emissions by 2040 constraint can be satisfied by generation from renewable generator types eligible for the 70 x 30 constraint as well as storage (battery storage and pumped storage hydro), nuclear, and DEFRs.

The model does not attempt to achieve 85% green-house gas emission reduction by 2050.

Resource Adequacy Constraints

Capacity reserve margins are included in the capacity expansion model to approximate resource adequacy requirements at the NYCA wide and Locality levels for the three New York Localities (Zone J, Zone K and Zone G-J). Installed Capacity Reserve Margin (IRM) and Locational Capacity Requirement (LCRs) for the 2021-2022 Capability Year are translated to their respective UCAP equivalent per the NYISO's installed capacity (ICAP) to UCAP translation and are preserved for all model years. The IRM and LCRs are modeled as minimum capacity reserve margins, which enforce a lower bound for the respective reserve margins.

The UCAP equivalent of the resource adequacy requirements are utilized because it has been found to be a more stable metric through time, as compared to the ICAP equivalent, especially in a system with high renewable resource penetration.[35]

For purposes of the capacity expansion model in this Outlook study, adjustments were assumed to the LCRs to address the future impacts on LCRs due to new transmission from planned transmission projects. Although the actual (scale of the) impact on the LCRs is unknown at this time, the following estimates as to how the LCRs may be impacted due to future transmission projects were made for purposes of this Outlook[36]:

[35] Whitepaper on "The Impacts of High Intermittent Renewable Resources" from the New York State Reliability Council https://www.nysrc.org/PDF/Reports/HR%20White%20Paper%20-%20Final%204-9-20.pdf

[36] Multiple scenarios were evaluated in the capacity expansion model and discussed with stakeholders at ESPWG to examine a range of potential IRM/LCR values. The approximate LCR impacts used in this study are illustrative and do not represent future study work to be performed to calculate actual values due to these transmission projects. https://www.nyiso.com/documents/20142/29418084/10%20System_Resource_Outlook_CapEx_Updates.pdf/

- 10%-point reduction in Zones G-J LCR to accommodate AC Transmission projects entering service in 2024
- 650 MW reduction in Zone J & Zones G-J LCRs to accommodate the Clean Path New York HVDC project

The minimum UCAP requirements of the capacity reserve margins assumed in the capacity expansion model are as follows:

Figure 31: Capacity Expansion IRM and LCR Values

Capacity Reserve Margin	Summer Requirement (%)[37]	Winter Requirement (%)[38]
NYCA IRM	110.11	110.56
Zones G-J LCR	84.43 model years 2021-2023; 74.43 model years 2024-2040	83.69 model years 2021-2023; 73.69 model years 2024-2040
Zone J LCR	78.14	78.31
Zone K LCR	97.85	95.48

Maximum Capacity Constraints

As noted above, constraints on the maximum allowable capacity by technology type by zone are assumed in the capacity expansion model for use in the Policy Case. These limitations are imposed to reflect physical land constraints in each respective area[39] as well as propose an assumed constraint on the amount of generation expansion that can occur on an annual basis (*e.g.*, no more than 10% of maximum allowable capacity by zone could be installed each year). The total capacity (MW) constraints imposed reflect all new builds by each respective technology type in each applicable zone, which includes generators in both the Contract Case as well as candidates for generation expansion.

The maximum capacity constraints have a significant impact on the amount of capacity builds that occur in each zone. Scenario testing revealed that many of the technologies will wait to build capacity until later in the model horizon, as a direct result of the cost assumptions for generators as the candidate generators for expansion assume a declining capital cost through time due to technological improvements[40]. Because the capacity expansion model seeks to optimize generation capital cost and production costs to determine a least cost future generation capacity buildout, the model will postpone construction of new units, if possible, to optimize the total system cost over the study period. However, it

[37] Summer 2021 http://icap.nyiso.com/ucap/public/ldf_view_icap_calc_selection.do

[38] Winter 2021-2022 http://icap.nyiso.com/ucap/public/ldf_view_icap_calc_selection.do

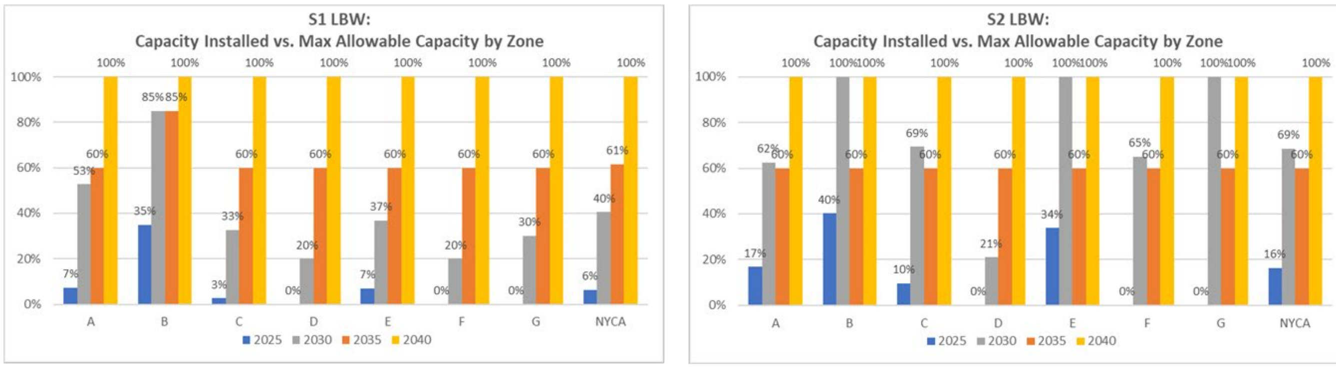
[39] Maximum allowable capacities are enforced for applicable generator types by zone based on 2040 limitations, per Appendix G: Annex 1: Inputs and Assumptions of the Climate Action Council Draft Scoping Plan. See: https://climate.ny.gov/-/media/Project/Climate/Files/IA-Tech-Supplement-Annex-1-Input-Assumptions.ashx

[40] Based on NREL 2020-ATB-data. See: https://data.nrel.gov/submissions/145

is unrealistic to assume that all construction will occur at the latest possible date (*e.g.*, 2035 for OSW capacity builds) due to construction, labor, and other realistic constraints; therefore, an annual build limit was imposed in each location to slow the growth of generation expansion for each generator type.

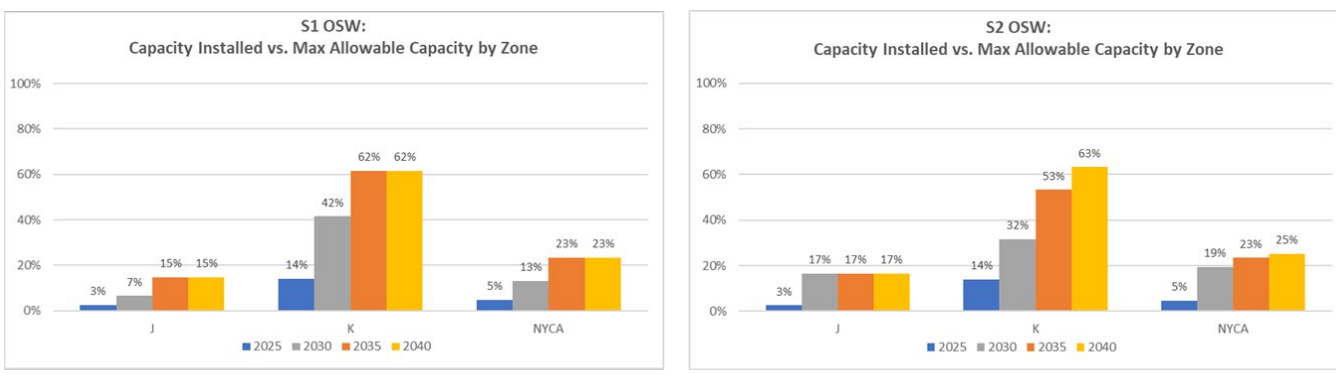
The following figure previews results for scenarios S1 and S2, which include the maximum capacity limitation assumptions described above, as a function of the maximum allowable capacity by zone. The percentage values show the amount of resource capability, by zone, that the optimization selected.

Figure 32: Land Based Wind Installed Capacity relative to Zonal Maximum Allowable Capacity



In both S1 and S2, the capacity builds from LBW reached its maximum allowable capacity for each zone by 2040, although the projection of LBW capacity builds throughout the model horizon differed due to differing constraints assumed for LBW[41].

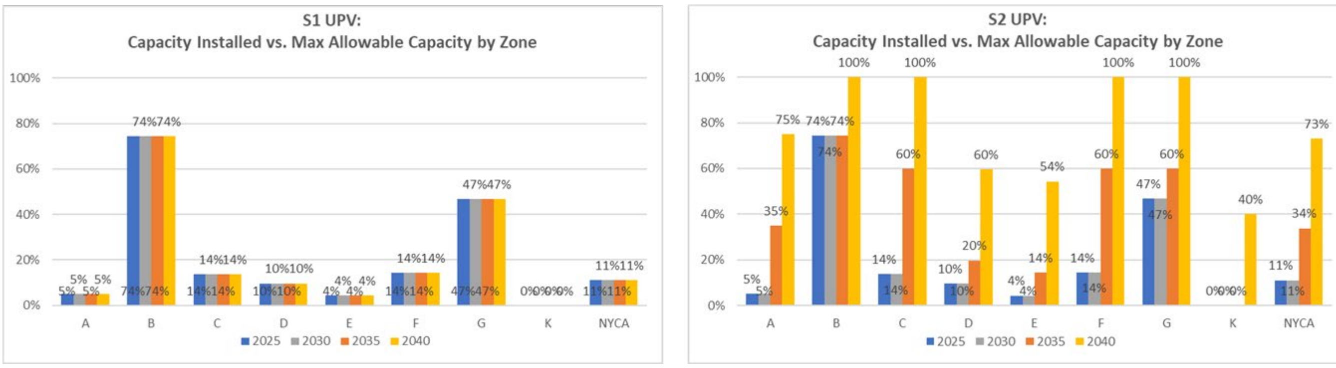
Figure 33: Offshore Wind Installed Capacity relative to Zonal Maximum Allowable Capacity



41 S2 assumes a lower maximum allowable capacity for LBW for model years 2021-2030, based on the 2030 limitations per the Climate Action Council Draft Scoping Plan. For comparison, S1 assumes the 2040 limitations for all model years. Due to this tighter constrained, the percent of allowable capacity installed decreases between years 2030 and 2035 in S2 because the capacity limit (MW) was relaxed after 2030.

The progression of OSW capacity builds differed between S1 and S2; a higher amount of OSW capacity was built by 2030 in S2 comparatively, due to the lower limit on LBW capacity allowed by 2030, and the total amount of OSW capacity built by 2040 was slightly higher in S2 as compared to S1.

Figure 34: Utility Scale Solar Installed Capacity relative to Zonal Maximum Allowable Capacity



There was no generation expansion from UPV in S1, while S2 had a significant amount of UPV capacity built. The capacity installed shown in S1 is reflective of the planned UPV capacity from state contracts, whereas the UPV capacity in S2 includes both planned builds as well as generation expansion. In S2, the UPV capacity reaches the maximum allowable capacity limits by 2040 in four out of the eight zones where UPV was eligible to build.

Model Limitations and Caveats

The assumptions and results of the capacity expansion model are the result of development of a NYCA specific modeling framework in PLEXOS that was based on initial porting of the GE-MAPS production cost database. The initial database was updated and amended to include parameters utilized in the capacity expansion portion of the PLEXOS model. This version of the capacity expansion model was developed as an initial reasoned trade-off between balancing model fidelity, runtime, and future uncertainty in knowledge of input assumptions to produce representations of possible outcomes of the future NYCA generation fleet and operations. Several versions of the model framework and assumptions were initially characterized by scenario testing to assess the sensitivity of the model to various input assumptions. While the model provides meaningful and logical insights into future capacity mix and generator operations, it should be viewed as a work in progress as additional improvements and capabilities accrete over the coming years. The capacity expansion model should be viewed as a potential projection of the future system mix and should not be understood as an endorsement of outcomes under any specific set of assumptions. It is primarily intended to inform NYISO studies and stakeholders of potential future generation fleet mixes under a multitude of scenarios.

Therefore, there are a number of important model limitations and caveats that need to be recognized when using and understanding the results of the capacity expansion model used in this Outlook study.

Model limitations

- The capacity expansion modeling framework employed will not capture curtailment of renewable resources due to specific transmission constraints. Curtailments will be reported as part of the Policy Case production cost model results.
- The capacity expansion model does not capture capacity market dynamics beyond simplified assumptions of satisfying current published IRM and LCR requirements on a UCAP basis.
- Zonal capacity expansion models include zonal limitations as a proxy for capacity siting constraints, however they do not provide insight into specific nodal locations where project interconnections are most likely or valuable to the system.

Model caveats

- The results of capacity expansion models are sensitive to the input assumptions related to cost and performance of resources and the modeling framework used to represent chronology and nodal/zonal representations.
- The state of charge for batteries is tracked (*i.e.*, the battery remains within its minimum and maximum state of charge levels) at the beginning and end of each model year. For each load block, the batteries can charge or discharge up to their maximum capacity (MW) rating.
- A set of proxy generic Dispatchable Emission Free Resources (DEFRs) was used to approximate a range of capital and operating costs given the uncertainty of future technology pathways to serve the role of a dispatchable generator.
    - All DEFRs are modeled as highly flexible resources with operational parameters (*i.e.*, heat rate, ramp rate, reserve contribution, start time, etc.) similar to a new natural gas combined cycle (but with zero emission rate).
    - While these proxy DEFR options may ultimately prove to not be representative of actual future technologies, they were used as a modeling framework to highlight the desired resource characteristics to meet state policies and the operational needs that would have to be met by the DEFRs when performing production cost simulations.
- The capacity value curves implemented in the capacity expansion model were developed as part of *the "New York's Evolution to a Zero Emission Power System "Grid in Evolution"" study* work.[42] The declining capacity value of solar, wind, and energy storage resources is a function of the load and operational profiles of resources, which may not be consistent across studies with varying assumptions regarding load and generation profiles but provide a reasonable approximation for purposes of this Outlook.

[42] https://www.nyiso.com/documents/20142/13245925/Brattle%20New%20York%20Electric%20Grid%20Evolution%20Study%20-%20June%202020.pdf/

Scenario specific caveats

- The additional scenarios reflect a change in assumptions based on the adjustments outlined in Appendix G.1 Capacity Expansion Scenario Assumptions and are independent of other scenarios conducted.
- Given uncertainty of future policy, technology, and costs, scenarios are intended to examine a range of values for a single assumption change.
    - For example, multiple scenarios have been conducted on the load forecast to capture a range of potential future load conditions which helped inform different load forecasts selected in S1 and S2.
- Separately, multiple scenarios were conducted to represent a range of DEFR costs (capital cost and fuel price) to capture a range of potential costs for the Dispatchable Emission Free Resource technologies.
- Assumption changes included in the scenarios are not an endorsement of estimate of the validity of the values modified from the assumptions for S1 and S2. Some scenarios do not represent realistic system performance but are helpful in identifying directional impacts and sensitivity to key variables (*e.g.* scenario removing declining capacity value curves).
- Combinations of presented scenario options may also be informative as some system changes may correlate or are reasonably likely to occur together.

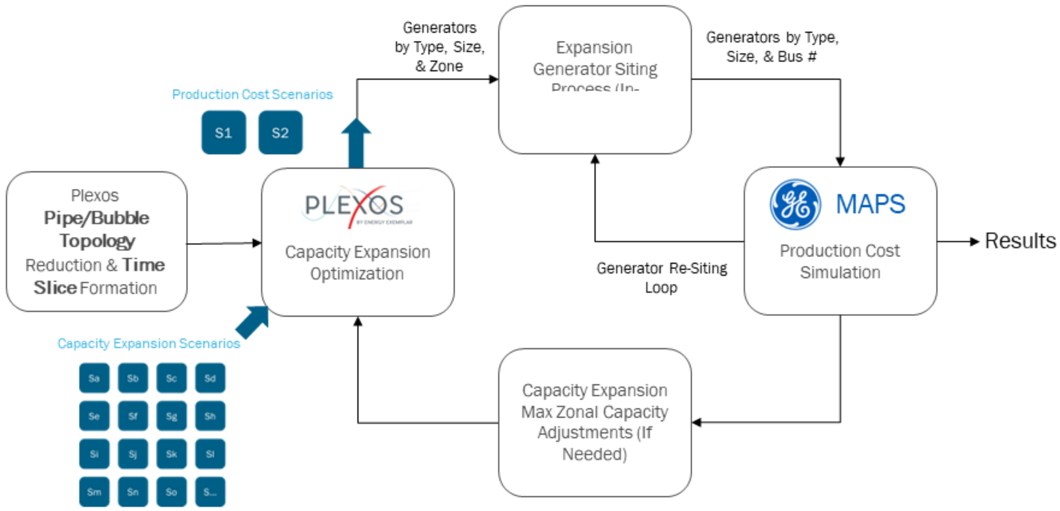
E.3.2. Production Cost Simulation

Production cost simulations allow a detailed view of the interconnected operation of transmission and generation across a large footprint with a high temporal resolution. While the assumptions across the capacity expansion and production cost models are aligned, generally the production cost model will provide more detailed insights into the specific economic and operational challenges that will occur under the capacity futures selected by the capacity expansion model. The focus of production cost modelling is to utilize the detailed transmission topology constraints identified to characterize renewable generation pockets that form as increasing amounts of resources locate in the same area. These pockets are associated with a disproportionally large share of the curtailments observed.

Capacity Expansion to Production Cost Model Translation

Production cost simulations for Policy Case scenarios S1 and S2 are based on the generator addition and retirement decisions from the capacity expansion model results, which are translated from a zonal to nodal attribution. This higher granularity allows for deeper insights into how the system performs on an hourly basis under a high renewable penetration scenario. The model data-flow diagram in Figure 35 below highlights the process used in translating the capacity expansion model results to the production cost model.

Figure 35: Policy Case Modelling Process Diagram



Generator Assumptions in Production Cost Simulation

New renewable generator additions from capacity expansion simulations for S1 and S2 were modeled in the production cost model as hourly fixed shapes for each year of the simulation. The shapes utilized for a specific generator type is consistent with that used in the capacity expansion model assumptions. Since capacity expansion produces zonal level aggregate generator addition capacities for each type (UPV, LBW, etc.), these values have to be allocated to buses in the production cost model to simulate actual injections at individual nodes.

The existing interconnection queue was leveraged as a starting point to identify probable points of interconnection for new resource additions. The proposed project capacity from the interconnection queue was taken as reference to calculate the proportion of total zonal capacity (from capacity expansion results for S1 and S2) to be added to the project location. This allowed the NYISO to examine system performance under conditions where most of the proposed projects in the interconnection queue would be in-service at varying capacities. DEFR units were placed in available buses vacated by retired fossil fuel-fired units. Energy storage was scheduled by MAPS production cost software and was distributed zonally to all load buses proportional to the nodal load factor, consistent with the process for distributing BTM-PV. Renewable generator additions were assigned REC prices based on current average contract prices by technology.[43]

[43] https://www.nyiso.com/documents/20142/28777318/04_System_Resource_Outlook_Update.pdf

Generator retirements/deactivations and derates were kept consistent with assumptions and results for S1 and S2. Any must-run or operational nomograms associated with fossil units assumed to retire were removed from the production cost model. These nomograms were not updated with replacement units in the Policy Cases.

Transmission System Assumptions in Production Cost Simulation

The Baseline Case transmission topology was assumed as the starting point for the Policy Cases. The following projects were added to the underlying powerflow for both S1 and S2 cases:

- **December 2025:** NYPA Northern New York Priority Transmission Project, the NYPA "Smart Path", modelled as several 230kV to 345kV transmission upgrades on the Moses South corridor in Northern NY;
- **December 2025:** Champlain Hudson Power Express (CHPE), modeled as 1,250 MW additional imports from Hydro Quebec into Zone J; and
- **June 2027:** Clean Path New York (CPNY), modeled as 1,300 MW HVDC line, connecting Zone E and Zone J.

The Champlain Hudson Power Express project is modeled as a fixed hourly injection directly into New York City as the Hydro Quebec system is not explicitly modelled. Elective upgrade facilities at the interconnection point were modeled as part of the project.

Process Feedback Loops

As depicted in Figure 35 above, there are several modelling feedback loops that are embedded into the Policy Case process in order to integrate the models being used. The "round-trip" feedback loop is fully described in Appendix E.2: Contract Case and more information can be found there. The production cost siting and capacity expansion feedback loops were both tested in this Outlook cycle but were not ultimately used. The information gleaned from testing each was very informative on system behavior but ultimately did not necessitate model changes.

The NYISO found that:

- The generation placement feedback loop was tested by relocating renewable generators with greater than 20% curtailment to adjacent bulk system locations. This was done until generators had less than the 20% curtailment threshold. It was found that the total system curtailment changed minimally during this process as the transmission congestion causing curtailment simply moved to different circuits.
- The NYISO tested the capacity expansion feedback loop, which was designed to capture model resolution discrepancies between the capacity expansion and production cost model. In this test, the maximum zonal capacity of specific resource types was adjusted in the capacity expansion model for NYCA zones with high levels of curtailment of a specific type. The results showed that as limits in LBW, UPV, and/or OSW were reduced, more DEFR capacity was added to make up for the capacity and/or energy attributes.

Modeling 2040

During the development process for the production cost simulations, the NYISO found that the 2040 simulation year contained a meaningful number of unsolved hours in the simulation. Approximately 8% of the total hours simulated were infeasible in the security constrained commitment and dispatch optimization. It was found that a major contributing factor of optimization non-convergence was the number of constraints encountered as the amount of generation capacity on the system grew by 36-45% and demand energy by 15-20% between 2035 and 2040 while the transmission system remained constant. A majority of the constraints encountered were at the 115kV and 138kV voltage levels. To enable a solution for 2040, a simplifying assumption of monitoring but NOT securing the 115kV and 138kV constraints was made. With this in mind, the 2040 results provide a reasonable indicator of the bulk transmission constraints that would exist if local transmission constraints were resolved. It also represents a system that is vastly different than the system of today. By 2040, it was assumed that the system will be enhanced to accommodate renewable resources, at least at the local level, to achieve policy goals. The 2040 case is designed to highlight the system congestion on higher kV elements under a policy buildout.