Appendix H: Capacity Expansion Model Results

2023-2042 System & Resource Outlook

A Report from the New York Independent System Operator

July 22, 2024

Appendix H: Capacity Expansion Model Results

Overview

Results of the capacity expansion model represent the optimization outcome to minimize total operational and fixed costs (including capital costs) over the entire 20-year study period. The system representation model of the NYCA (plus neighboring systems, including ISO-NE, PJM, and IESO) included modeling for each year with select representative days, as further described in Appendix D: Modeling and Methodologies, while satisfying policies and other constraints. Given that the global optimization results would differ if performed on a full nodal system representation with hourly resolution, which is performed in the production cost modeling in a single year, these results should not be viewed as buildouts that would fully achieve the CLCPA mandates or necessarily maintain a reliable system.[1] Rather, these results represent potential future scenarios that can meet policy objectives absent the detailed technical constraints that are evaluated further in production cost simulations for the Policy Case scenarios.

For purposes of this Outlook, the three capacity expansion scenarios are the Lower Demand scenario, the Higher Demand scenario, and the State Scenario. The resulting resource buildouts from the Lower and Higher Demand scenarios are further evaluated through production cost simulations in this Outlook. The results from these three scenarios are intended to show a range of potential future capacity buildouts based on differing input assumptions that consider the large uncertainty in the composition of the future grid. The NYISO developed the Lower and Higher Demand scenarios in consideration of feedback from NYISO stakeholders and coordinated extensively with the state agencies (DPS and NYSERDA) on the State Scenario as part of the Coordinated Grid Planning Process (CGPP). This Outlook does not endorse one scenario over the other, and these scenarios should be viewed as possible outcomes given the large uncertainty in the composition of the future system.

The State Scenario results presented here are preliminary and may be further modified through work in CGPP. Because model development for the State Scenario will continue beyond this Outlook cycle to support the state's CGPP, the results presented in this appendix represent a range of possible outcomes, bookended by two separate cases that represent differing headroom assumptions. The first case assumes no headroom within the model and, therefore, incurs no additional cost to upgrade the local transmission system as new generation resources are added.

[1] Resource adequacy analysis would be required to confirm reliability of the system, and such analysis is outside the scope of the System & Resource Outlook process.

This case is referred to as the "No Headroom Case." The second case, which uses assumptions provided by NYSERDA and DPS, assumes a cost to add zonal headroom (i.e., upgrade the local transmission system) where the amount of headroom added is directly tied to the generation within each zone. In this case, headroom incurs a 15% compounding cost for every additional 1 GW of headroom required within each zone. This case is referred to as the "15% Compounding Headroom Cost Case." The initial NYCA-level results presented in the following section use results from the 15% Compounding Headroom Cost Case. However, the NYCA-level results between the two State Scenario headroom cases are very similar—particularly with respect to total capacity per technology type in 2042. The change in the headroom assumption between these two cases primarily impacts the distribution of resources between zones and is described in detail later in this appendix. For a more detailed description of headroom, please refer to Appendix D: Modeling and Methodologies.

Capacity Expansion Model Results

For all three capacity expansion scenarios, the results show a significant amount of capacity from renewable generation and DEFRs installed by 2040, with approximately 95 GW of installed capacity for the Lower Demand scenario, approximately 114 GW for the Higher Demand scenario, and approximately 124 GW for the State Scenario. These installed capacity values only include NYCA generators and qualifying imports from Hydro-Québec. This level of total installed capacity is needed to be installed by 2040 to satisfy the state policy mandates, energy constraints, and capacity margin targets that have been incorporated in the model.

Of this total amount of installed capacity, approximately 47 GW, 68 GW, and 78 GW are attributed to new generation expansion for the Lower Demand scenario, Higher Demand scenario, and the State Scenario, respectively. This is in addition to the 16 GW of renewable generation capacity that is planned through state contracts.[2] For comparison, the Base and Contract Cases have approximately 40 GW and 57 GW, respectively, of total installed capacity in 2040. For reference, the total installed capacity was approximately 42 GW in the 2021 Benchmark simulation.

To comply with the CLCPA requirement of a zero-emissions grid by 2040, the NYISO modeled all fossil-fuel generators as retired by 2040 based on the assumption that these CO_2 emitting generators cannot operate starting January 1, 2040. Existing zero-emitting generation, such as

[2] Renewable energy projects assumed as firm resource additions include those in the NYSERDA Renewable Energy Certification contracts database and/or have announced awards as of the lockdown date for the 2023-2042 System & Resource Outlook Contract Case (October 30, 2023).

nuclear, hydro, LBW, and UPV, remains operational in the system throughout the study horizon.

Figure H-1: Capacity Expansion Model Results Comparison

As shown in Figure H-1, the generation and capacity mix for the Lower Demand scenario and the Higher Demand scenario had similar results driven by similar input assumptions, particularly candidate resource types and their associated costs. Where these two scenarios differ is in the magnitude of resources built driven by differing load growth assumptions. With the increase in load growth in the Higher Demand scenario, this scenario builds out to a higher level of renewable penetration, particularly UPV, and larger amounts of DEFR capacity than the Lower Demand scenario.

Figure H-1 also shows that the resulting capacity mix in the State Scenario is notably different from the Lower Demand scenario and the Higher Demand scenario. This difference is driven by differing input assumptions, particularly hydrogen-powered DEFR candidates with high operating costs in the State Scenario, as well as different renewable resource cost assumptions. For this reason, the State Scenario model primarily builds hydrogen-powered DEFR capacity to help satisfy Locational Capacity Requirements (LCR) but relies on energy from renewable resources with lower operating costs. In all scenarios, capital cost is a major factor in the optimization for selecting certain resource(s). The technology-type locations that are selected (e.g., zonal buildout) are highly dependent upon relative locational specific costs for each technology.

In all scenarios, a significant amount of LBW capacity was built by 2040. As compared to the other renewable technologies available to the model, LBW was preferred due to its assumed capital cost, generation profile (i.e., HRM shape's implied capacity factor), and UCAP ratings. It is important to note that renewable resources (i.e., LBW, UPV, and OSW) are limited to maximum potential capacity levels within each zone.[3] These limitations are applicable at varying degrees for all renewable resources and are driven by constraints, particularly land or lease area availability, informed by NYSERDA's Large Scale Renewable Supply Curve analysis. While the max potential of LBW is not close to being met NYCA wide in the Lower Demand scenario, the State Scenario results show that LBW capacity reaches its max potential due to the assumed high energy demand and comparably high operating cost hydrogen-powered DEFR option. Similarly, in the Higher Demand scenario, LBW is an optimal resource and uses all but approximately 1 GW of maximum allowed capacity statewide.

In both the Lower and Higher Demand scenarios, DEFRs are selected to build as a secondary economic option (compared to LBW) to supply capacity and/or energy needs due to their high firm capacity rating and flexible operational characteristics.

In the Higher and Lower Demand scenarios, the DEFR options are technology agnostic and available using three separate cost combinations—High Capital/Low Operating cost, Medium Capital/Medium Operating cost, and Low Capital/High Operating cost. However, in the State Scenario, the DEFR option is limited to new and retrofit hydrogen-powered combustion turbines that use either simple cycle or combined cycle technology. These hydrogen-powered generators, despite having a competitive capital cost of modern combustion turbine technology, have a very high operating cost driven by the high fuel price assumed for hydrogen fuel. Furthermore, per the State Scenario's assumptions on electrolysis, hydrogen-powered generators incur additional electrolysis load and, therefore, incur additional system costs. Because of the assumptions in the State Scenario, the results show that hydrogen-powered generator capacity is built primarily to serve LCRs downstate. This is demonstrated by the significant amount of hydrogen-powered generator capacity built in downstate regions but with very low utilization.

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[3] Renewable resource locations and availability are determined by supply curve analysis undertaken by NYSERDA and consultants in 2023.

Notably, OSW generation has the highest capital cost investment of all renewable resources and is second highest of all candidate resources after the High Capital/Low Operating cost DEFR option.[4] Subsequently, scenario results show that OSW generation is not typically selected for generation expansion beyond the requirement of 9 GW by 2035. The State Scenario results show OSW capacity exceeding the minimum requirement to help supply energy needs, which is primarily driven by the high operating cost that would be incurred by the hydrogen-powered generators and cumulative limit on solar capacity.

Detailed results specific to each scenario are described further in the following sections.

Lower Demand Capacity Expansion Results

Results specific to the Lower Demand scenario are included in Figures H-2 through H-6 below.

Figure H-2 displays 2021 Benchmark capacity (GW) and generation (TWh) alongside the capacity expansion model outputs provided in five-year intervals. Results on the NYCA level are broken out by generation type in both graphical and tabular form. The generation table includes calculation of total, renewable, and zero-emissions generation relative to the load in units of energy and shows that the CLCPA 70% renewable generation by 2030 and a zero-emissions grid by 2040 policy constraints were satisfied. The resulting CO_2 emissions (million tons) are also included in the figure.

The results for the Lower Demand scenario show that a significant amount of DEFR capacity is needed to support higher loads and renewable penetration in 2040. The High Capital/Low Operating cost DEFR option generates a significant amount of energy in 2040, while the Low Capital/High Operating cost DEFR option generates very little energy. The Low Capital/High Operating cost DEFR option is primarily selected to help satisfy the capacity reserve margins at the statewide and locality levels due to its high assumed UCAP rating and low capital cost compared to other resource types. While an option for expansion, the Medium Capital/Medium Operating cost DEFR option is not selected to build in the Lower Demand scenario.

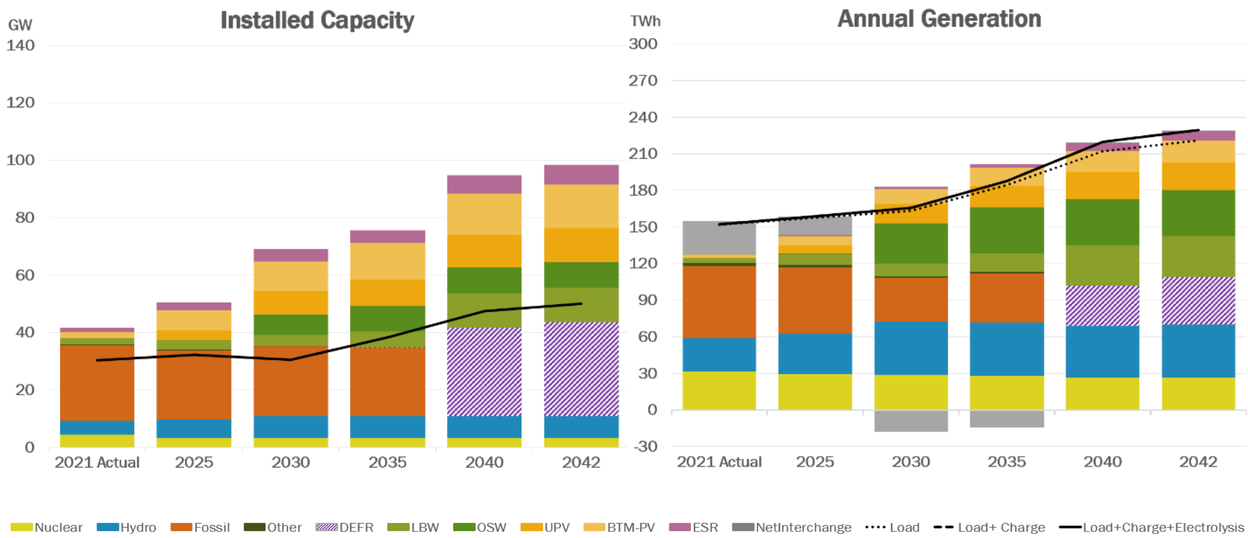
OSW capacity does not exceed the 9 GW minimum requirement prescribed by CLCPA. As previously noted, OSW is assumed to have the highest capital cost with the exception of the High Capital Cost/Low Operating Cost DEFR option. The high capital cost investment and relatively lower UCAP rating of OSW (as compared to candidate DEFRs) are the primary reasons for this result.

[4] This candidate DEFR is include as an option in the Lower and Higher Demand scenarios.

Figure H-3 shows the distribution of both candidate and awarded resources between upstate (Zones A-F) and downstate (Zones G-K). By 2040, the results show a similar total of added capacity between upstate and downstate with more renewables (i.e., LBW and UPV) concentrated upstate. Furthermore, Figure H-4 shows capacity distribution at a zonal level. A higher concentration of a particular resource in a single zone can be driven by economics, capacity margin target, or the maximum resource potential. The results for the Lower Demand scenario show DEFR capacity distributed in all zones with a concentration downstate, particularly in Zone J, to help support locational capacity margin targets. In addition, UPV, LBW, and OSW are distributed across all zones where these resources are available.

Figure H-6 shows the generation characteristics in the Lower Demand scenario. Some DEFRs generate during most system conditions and operate in a similar manner to the existing fossil fleet when comparing 2030 to 2040. This DEFR generation is primarily produced by the High Capital/Low Operating cost DEFR option, while the Low Capital/High Operating cost DEFR option only generates at near peak periods. In 2042, the High Capital/Low Operating cost DEFR option often generates on a fleet-wide basis near its maximum rated capacity. In contrast, the Low Capital/High Operating cost DEFR option operates on a fleet-wide basis closer to 50% of its maximum rated capacity, which highlights its purpose for capacity needs rather than energy needs. Furthermore, OSW and LBW play a significant role in meeting energy demand during winter peak, while UPV plays an important role during summer peak periods. To better understand the representative days highlighted in Figure H-6, please see the 'Time Representation" description in Appendix D: Modeling and Methodologies and Figure H-5, which includes a legend for interpreting the labeling for each representative day.

Figure H-2: Lower Demand Scenario Capacity Expansion Model Results



Capacity (Summer MW)						
	2021	2025	2030	2035	2040	2042
Nuclear	4,378	3,342	3,342	3,342	3,342	3,342
Fossil	26,345	24,122	24,122	23,666	-	-
DEFR - HcLo	-	-	-	-	5,042	5,042
DEFR - McMo	-	-	-	-	-	-
DEFR - LcHo	-	-	-	235	25,655	27,606
Hydro	4,868	6,381	7,665	7,665	7,665	7,665
LBW	2,227	3,291	3,881	5,325	12,000	12,000
OSW	-	136	6,990	9,000	9,000	9,000
UPV	32	3,135	8,422	9,204	11,365	11,821
BTM-PV	2,116	7,097	10,153	12,644	14,444	14,988
Storage	1,405	2,905	4,405	4,405	6,262	7,044
Total	41,686	50,650	69,147	75,652	94,775	98,508
Annual Peak (MW)	30,397	32,279	30,490	38,297	47,493	49,967

Generation (GWh)						
	2021	2025	2030	2035	2040	2042
Nuclear	31,609	29,276	28,831	27,950	26,544	26,438
Fossil	59,154	54,403	35,687	40,342	-	-
DEFR - HcLo	-	-	-	-	30,606	35,116
DEFR - McMo	-	-	-	-	-	-
DEFR - LcHo	-	-	-	-	2,168	3,880
Hydro	27,379	33,281	43,688	43,687	42,408	43,686
LBW	4,024	8,841	10,700	14,971	33,660	33,536
OSW	-	549	32,708	37,648	37,806	37,649
UPV	51	6,528	15,991	17,569	21,759	22,603
BTM-PV	2,761	7,718	12,024	15,232	17,582	18,311
Storage	355	1,064	2,171	2,805	6,530	7,494
Total Generation	127,930	143,650	183,233	201,596	219,062	228,715
RE Generation	34,215	56,917	115,110	129,107	153,215	155,785
ZE Generation	65,824	86,192	143,941	157,057	212,532	221,220
Net Interchange	27,222	15,074	(17,674)	(14,109)	478	664
Load	151,979	157,528	163,222	184,439	212,121	220,946
Load+Charge	152,334	158,754	165,738	187,696	219,831	229,631
Load+Charge+Electrolysis	152,334	158,754	165,738	187,696	219,831	229,631
% RE [RE/Load]	23%	36%	71%	70%	72%	71%
% ZE [ZE/Load]	43%	55%	88%	85%	100%	100%

Emissions (million tons)						
	2021	2025	2030	2035	2040	2042
CO_2 Emissions	22.24	23.11	15.00	17.07	-	-

* Storage includes Pumped Storage Hydro and Batteries
* Utility solar (UPV) includes existing and new UPV
* Hydro includes hydro imports from Hydro Quebec
* Land-Based Wind (LBW), Offshore Wind (OSW), Renewable (RE), Zero Emissions (ZE)
* Dispachable Emission Free Resource (DEFR), High Capital Low Operating (HcLo), Medium Capital Medium Operating (McMo), Low Capital High Operating (LcHo)
*Net Interchange is reported relative to New York (imports +, exports -)

Figure H-3: Lower Demand Scenario Upstate Vs Downstate Cumulative Capacity Additions

Capacity Additions (MW)	2025		2030		2035		2040		2042	
	A-F	G-K	A-F	G-K	A-F	G-K	A-F	G-K	A-F	G-K
UPV	1,667	40	6,954	40	7,736	40	9,139	798	9,139	1,254
LBW	340	0	930	0	2,374	0	8,835	214	8,835	214
OSW	0	0	0	6,854	0	8,864	0	8,864	0	8,864
DEFR	0	0	0	0	235	0	13,708	16,989	14,903	17,745
Storage	972	478	1,161	1,789	1,161	1,789	1,161	3,646	1,161	4,428

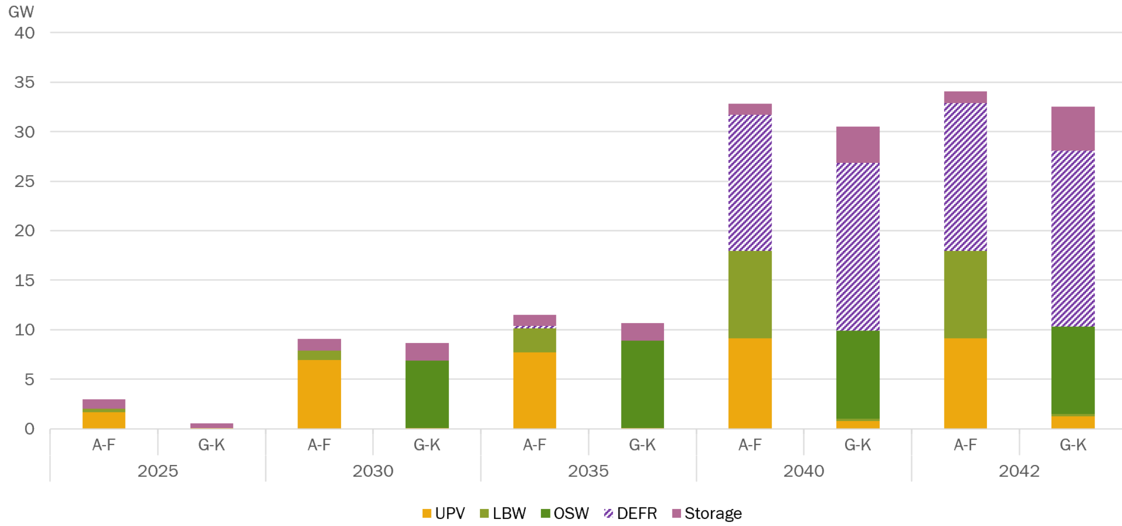


Figure H-4: Lower Demand Scenario Cumulative Capacity Additions by Zone

Capacity Additions (MW)	2042										
	A	B	C	D	E	F	G	H	I	J	K
UPV	955	1,275	1,650	1,611	1,579	2,069	790	0	0	0	464
LBW	2,127	972	145	298	4,324	969	214	0	0	0	0
OSW	0	0	0	0	0	0	0	0	0	5,366	3,498
DEFR	2,235	1,890	2,184	2,159	2,155	4,279	2,059	1,658	1,850	9,676	2,503
Storage	40	351	421	178	171	0	0	0	0	2,438	1,990

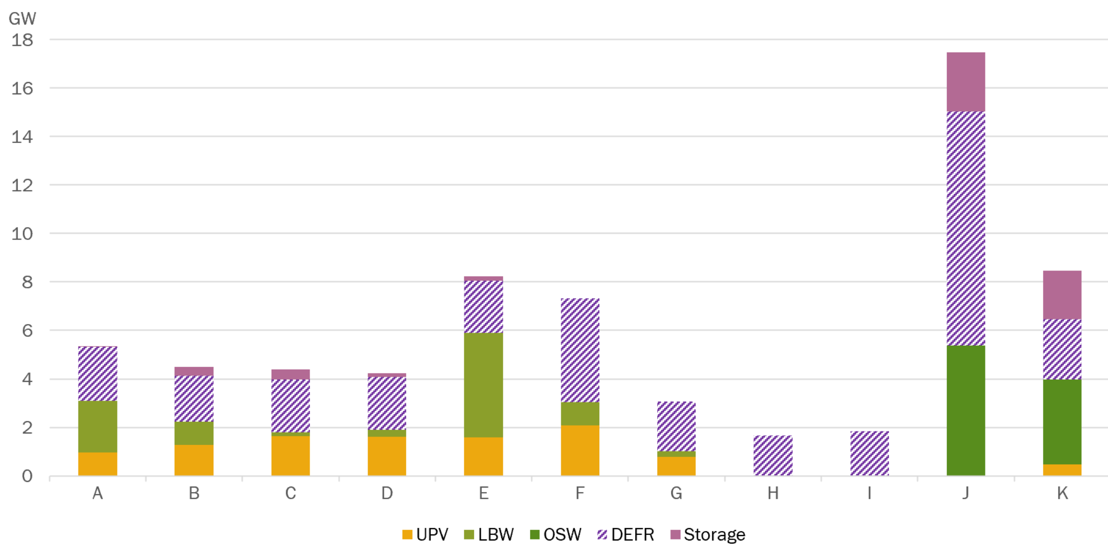
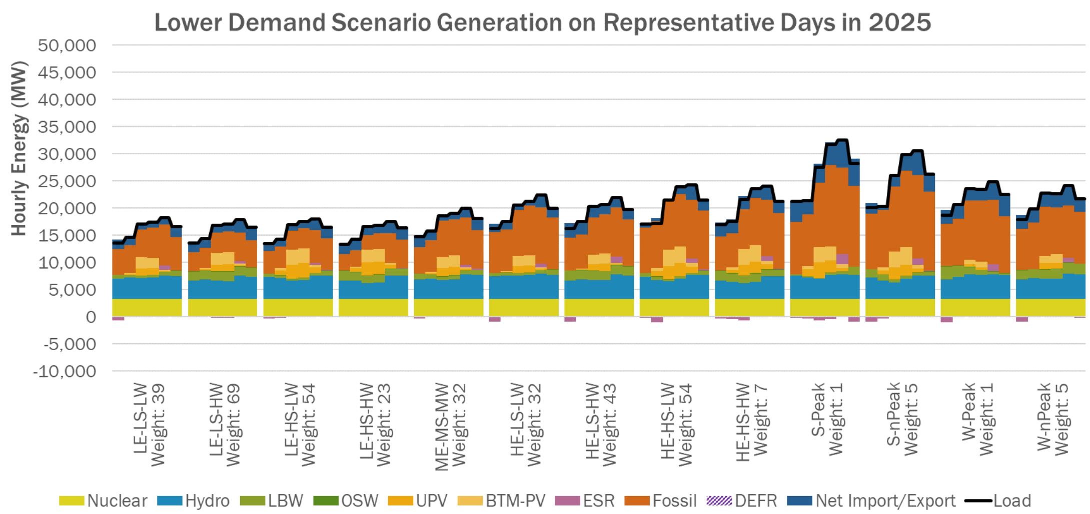
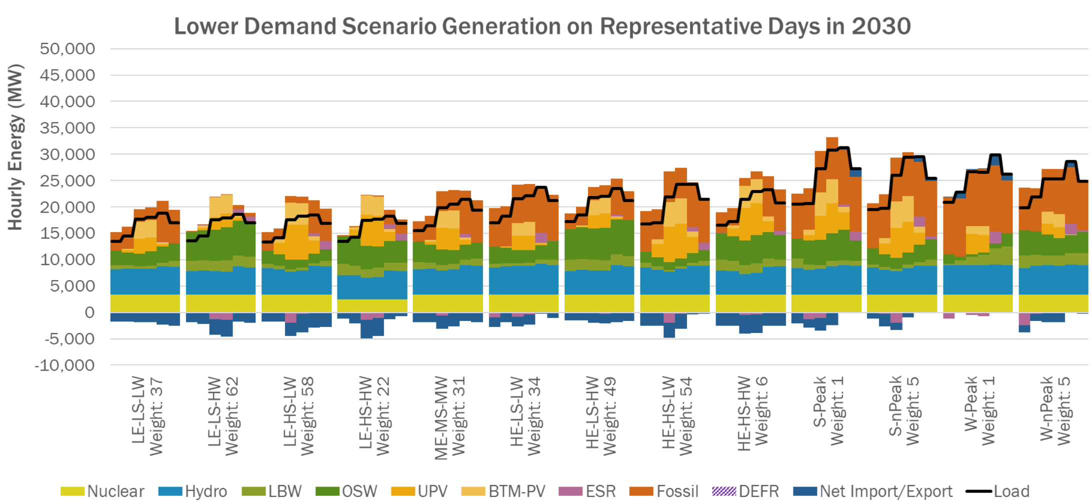


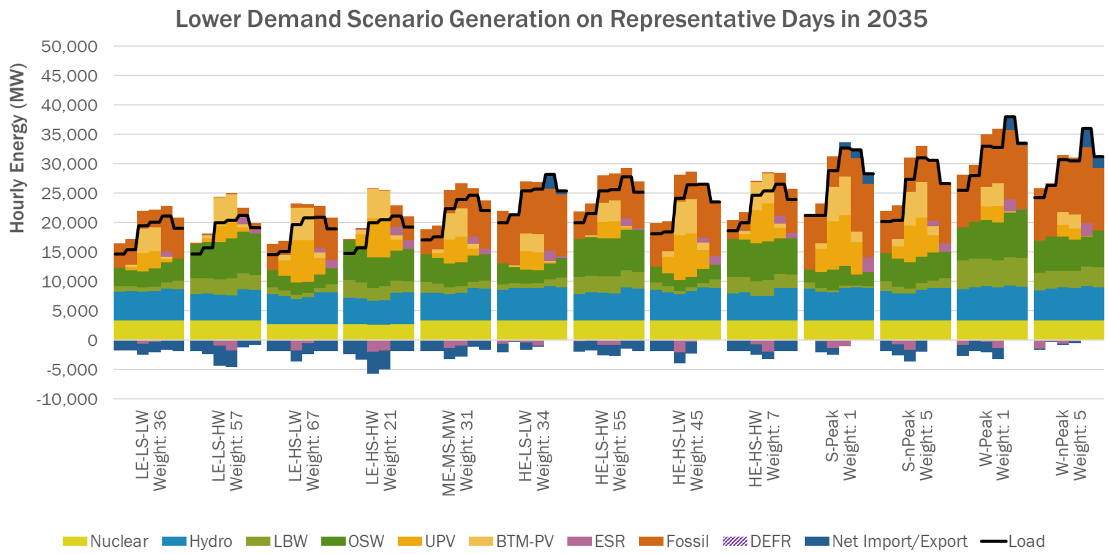
Figure H-5: Representative Days Label Legend

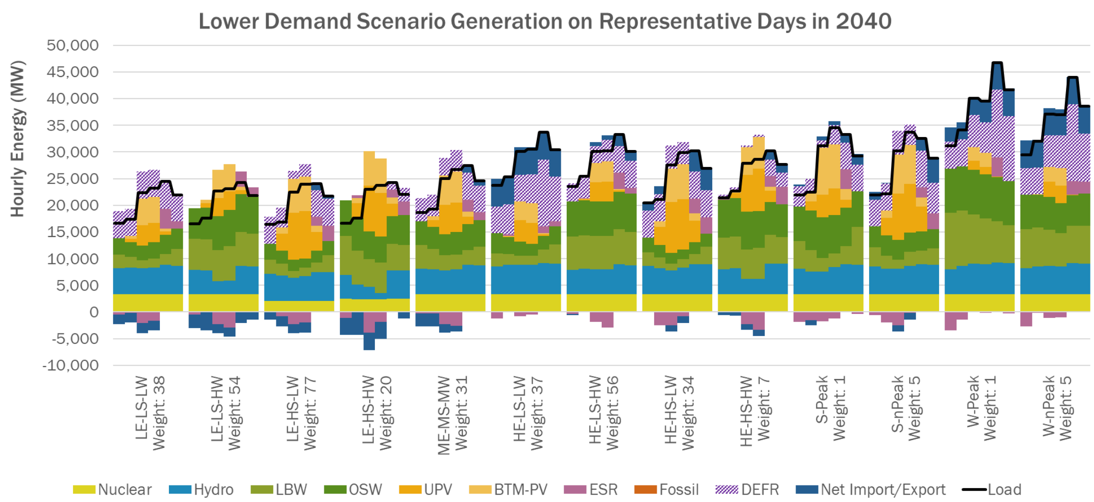
Representative Day	Description
LE-LS-LW	Low Energy, Low Solar, Low Wind
LE-LS-HW	Low Energy, Low Solar, High Wind
LE-HS-LW	Low Energy, High Solar, Low Wind
LE-HS-HW	Low Energy, High Solar, High Wind
ME-MS-MW	Med Energy, Med Solar, Med Wind
HE-LS-LW	High Energy, Low Solar, Low Wind
HE-LS-HW	High Energy, Low Solar, High Wind
HE-HS-LW	High Energy, High Solar, Low Wind
HE-HS-HW	High Energy, High Solar, High Wind
S-Peak	Summer Peak
S-nPeak	Summer Near-Peak
W-Peak	Winter Peak
W-nPeak	Winter Near-Peak

Figure H-6: Lower Demand Scenario Generation on Representative Days by Year









Higher Demand Capacity Expansion Results

Results specific to the Higher Demand scenario in the Policy Case are included in Figures H-7 through H-10. With approximately 39 TWh more energy demand in the Higher Demand scenario than the Lower Demand scenario by 2042, approximately 25 GW of additional capacity are required in the Higher Demand scenario by the end of the study horizon. A significant portion of this increased load is due to changed assumptions for large loads. Where the Lower Demand scenario uses the "Baseline" forecast for large loads from the 2023 Gold Book, the Higher Demand scenario uses the "Higher Demand Policy Scenario" forecast and, therefore, adds an additional 8 TWh of load.[5] In addition, there is a reduced penetration of behind-the-meter PV in the Higher Demand

[5] NYISO's 2023 Load & Capacity Data Report (Gold Book).

scenario that results in an increased need for utility-scale resources. Overall, the impact of this increased load sets a higher need for generation capacity, particularly to comply with the capacity reserve margin requirements and increases the amount of energy required to meet the CLCPA's 70% renewable mandate.

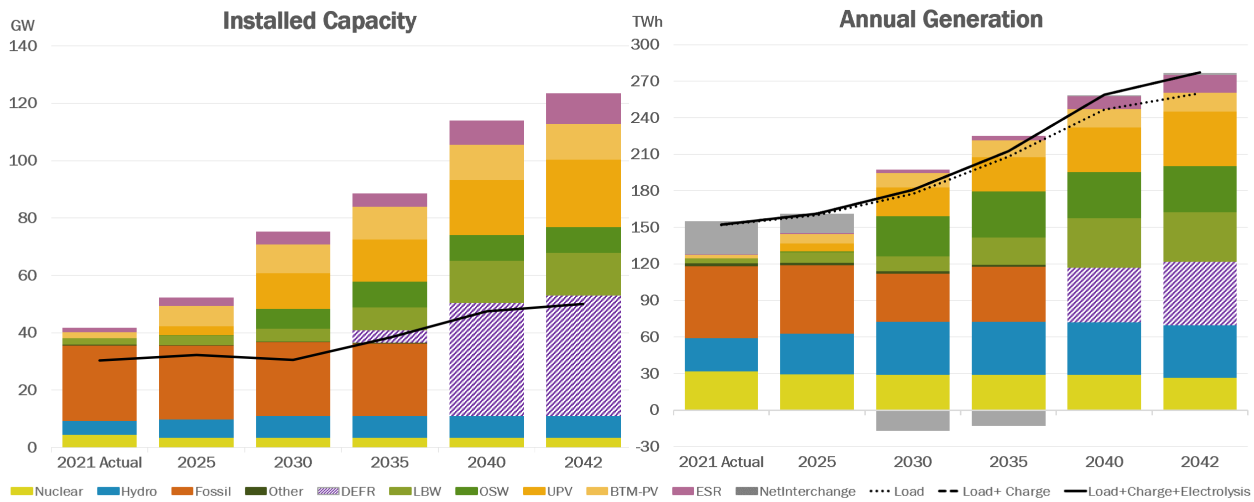
The results for the Higher Demand scenario show that even more DEFR capacity is needed to support both higher peak and energy demand. Like the Lower Demand scenario, the High Capital/Low Operating cost DEFR option generates a significant amount of energy in 2040, while the Low Capital/High Operating cost DEFR option generates much less. The Low Capital/High Operating cost DEFR option is primarily selected to help satisfy the capacity reserve margins at the statewide and locality levels. To help illustrate, the average capacity factor of the High Capital/Low Operating cost DEFR option in 2040 is 63% (or approximately 40 TWh of annual generation) for a total of 7 GW of capacity, while the average capacity factor of the Low Capital/High Operating cost DEFR option is 2% (or approximately 4 TWh of annual generation) for a total of 33 GW.

To meet the increase in energy required to meet the 70% renewable policy mandate, the results show an increase in both LBW and UPV. However, even with the increase in energy demand, OSW capacity still does not exceed the 9 GW minimum requirement prescribed by CLCPA due to its comparably high capital cost investment.

Regarding the distribution of both candidate and awarded resources between upstate (Zones A-F) and downstate (Zones G-K) in Figure H-8, the results show a higher level of total capacity downstate as compared to upstate by 2040. Such result is largely driven by more DEFR capacity and a balance of renewable capacity. This shift in more capacity downstate compared to the Lower Demand scenario is driven by the higher proportion of demand in this region. Because there is no limitation to building DEFR capacity in downstate and these zones are also required to build capacity to meet local capacity reserve margins, there likely is a benefit to having these resources located near load centers instead of facing transmission limitations in transferring energy from upstate to downstate. Figure H-9 shows the capacity distribution at a zonal level and shows similar trends to the Lower Demand scenario. However, the Higher Demand scenario shows an increase in UPV capacity primarily located in Zone F that is economically driven by the zonal-level cost assumptions for UPV (which are notably different than the county-level UPV cost assumptions used in the State Scenario) and differences in resource profile between zones. The zonal UPV capital costs for UPV located in Zone E and Zone F are comparable. However, Zone F has a slight capacity factor advantage and, therefore, the model chooses to locate UPV in Zone F over Zone E.

Regarding the generation characteristics in the Higher Demand scenario, according to Figure H-10, the trends remain consistent, as compared to the Lower Demand scenario, with more generation from LBW, UPV, and DEFR to accommodate higher demand. UPV contributes most significantly in the Higher Demand scenario, resulting in approximately double the amount of generation compared to the Lower Demand scenario.

Figure H-7: Higher Demand Scenario Capacity Expansion Model Results



Capacity (Summer MW)							
		2021	2025	2030	2035	2040	2042
Nuclear		4,378	3,342	3,342	3,342	3,342	3,342
Fossil		26,345	25,753	25,753	25,296	-	-
DEFR - HcLo		-	-	-	-	6,748	7,013
DEFR - McMo		-	-	-	-	-	-
DEFR - LcHo		-	-	-	4,332	32,660	35,033
Hydro		4,868	6,381	7,631	7,665	7,665	7,665
LBW		2,227	3,291	4,403	8,025	14,653	14,750
OSW		-	136	6,990	9,000	9,000	9,000
UPV		32	3,135	12,465	14,692	19,136	23,498
BTM-PV		2,116	7,097	10,032	11,420	12,308	12,567
Storage		1,405	2,905	4,405	4,683	8,547	10,673
Total		41,686	52,280	75,246	88,680	114,059	123,540
Annual Peak (MW)		30,397	33,100	33,495	43,338	57,015	61,346

Generation (GWh)							
		2021	2025	2030	2035	2040	2042
Nuclear		31,609	29,276	28,791	28,947	28,929	26,326
Fossil		59,154	56,261	39,737	45,190	-	-
DEFR - HcLo		-	-	-	-	40,724	46,143
DEFR - McMo		-	-	-	-	-	-
DEFR - LcHo		-	-	-	-	3,996	5,948
Hydro		27,379	33,282	43,679	43,422	43,097	43,255
LBW		4,024	8,837	12,239	22,539	40,853	40,869
OSW		-	548	32,661	37,651	37,789	37,650
UPV		51	6,529	23,805	28,155	36,738	44,989
BTM-PV		2,761	7,720	11,880	13,774	15,022	15,399
Storage		355	960	2,679	3,816	10,504	14,806
Total Generation		127,930	145,401	197,415	225,297	257,653	275,387
RE Generation		34,215	56,916	124,264	145,541	173,500	182,163
ZE Generation		65,824	86,192	153,055	174,488	247,149	260,581
Net Interchange		27,222	15,665	(16,983)	(13,095)	970	1,440
Load		151,979	159,991	177,520	207,916	246,751	260,233
Load+Charge		152,334	161,092	180,664	212,476	258,910	277,078
Load+Charge+Electrolysis		152,334	161,092	180,664	212,476	258,910	277,078
% RE [RE/Load]		23%	36%	70%	70%	70%	70%
% ZE [ZE/Load]		43%	54%	86%	84%	100%	100%

Emissions (million tons)						
	2021	2025	2030	2035	2040	2042
CO_2 Emissions	22.24	24.04	16.82	19.34	-	-

* Storage includes Pumped Storage Hydro and Batteries
* Utility solar (UPV) includes existing and new UPV
* Hydro includes hydro imports from Hydro Quebec
* Land-Based Wind (LBW), Offshore Wind (OSW), Renewable (RE), Zero Emissions (ZE)
* Dispachable Emission Free Resource (DEFR), High Capital Low Operating (HcLo), Medium Capital Medium Operating (McMo), Low Capital High Operating (LcHo)
*Net Interchange is reported relative to New York (imports +, exports -)

Figure H-8: Higher Demand Scenario Upstate Vs Downstate Cumulative Capacity Additions

Capacity Additions (MW)	2025		2030		2035		2040		2042	
	A-F	G-K	A-F	G-K	A-F	G-K	A-F	G-K	A-F	G-K
UPV	1,667	40	10,997	40	13,224	40	15,573	2,135	18,869	3,201
LBW	340	0	1,452	0	4,860	214	11,274	428	11,371	428
OSW	0	0	0	6,854	0	8,864	0	8,864	0	8,864
DEFR	0	0	0	0	3,689	643	16,763	22,645	16,766	25,280
Storage	1,365	85	1,738	1,212	1,738	1,490	2,586	4,506	3,721	5,497

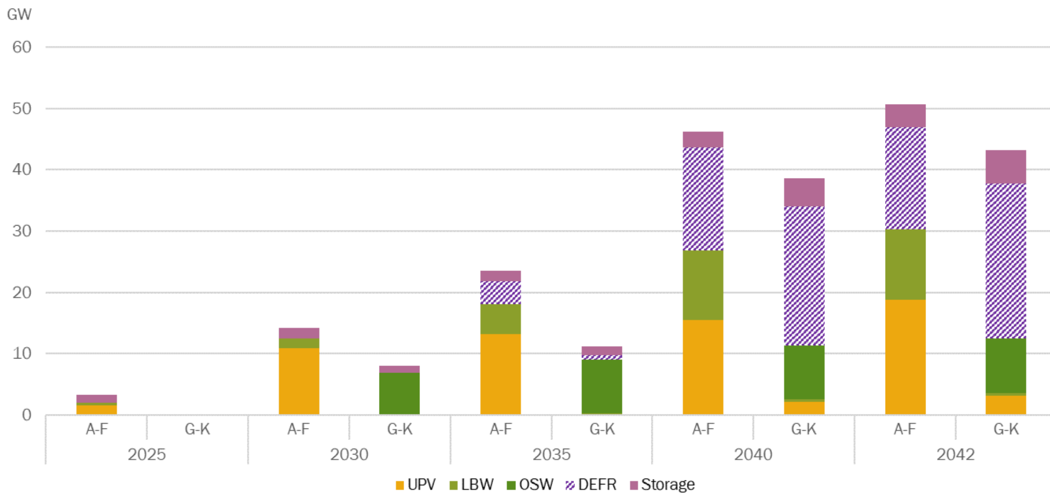


Figure H-9: Higher Demand Scenario Cumulative Capacity Additions by Zone

Capacity Additions (MW)	2042										
	A	B	C	D	E	F	G	H	I	J	K
UPV	1,404	1,275	1,650	1,611	2,554	10,375	2,653	0	0	0	548
LBW	2,299	972	2,292	395	4,444	969	374	54	0	0	0
OSW	0	0	0	0	0	0	0	0	0	5,366	3,498
DEFR	2,578	2,631	2,177	2,430	2,384	4,566	2,031	3,042	2,379	13,257	4,570
Storage	40	737	392	298	271	1,983	543	0	583	2,381	1,990

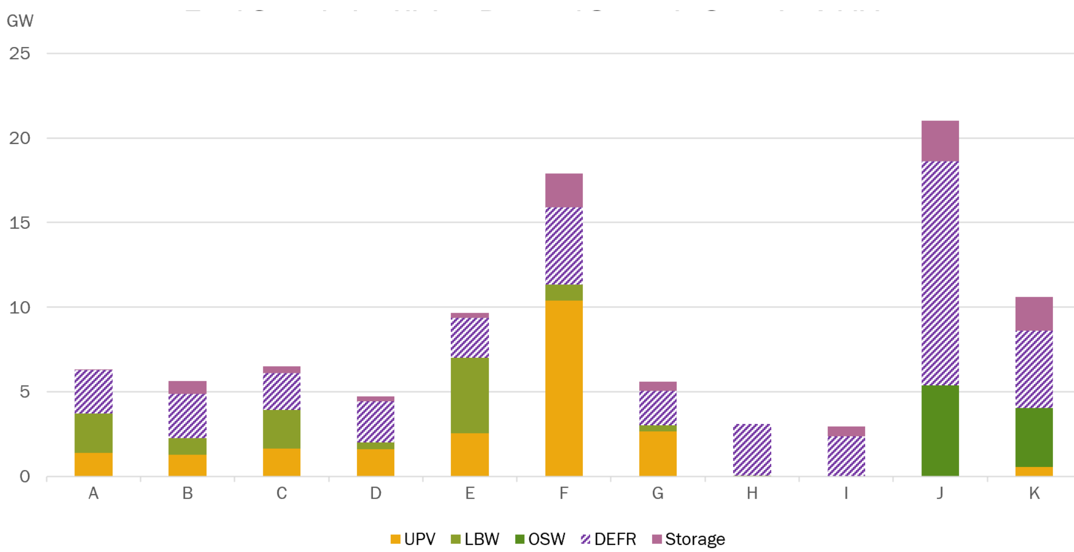
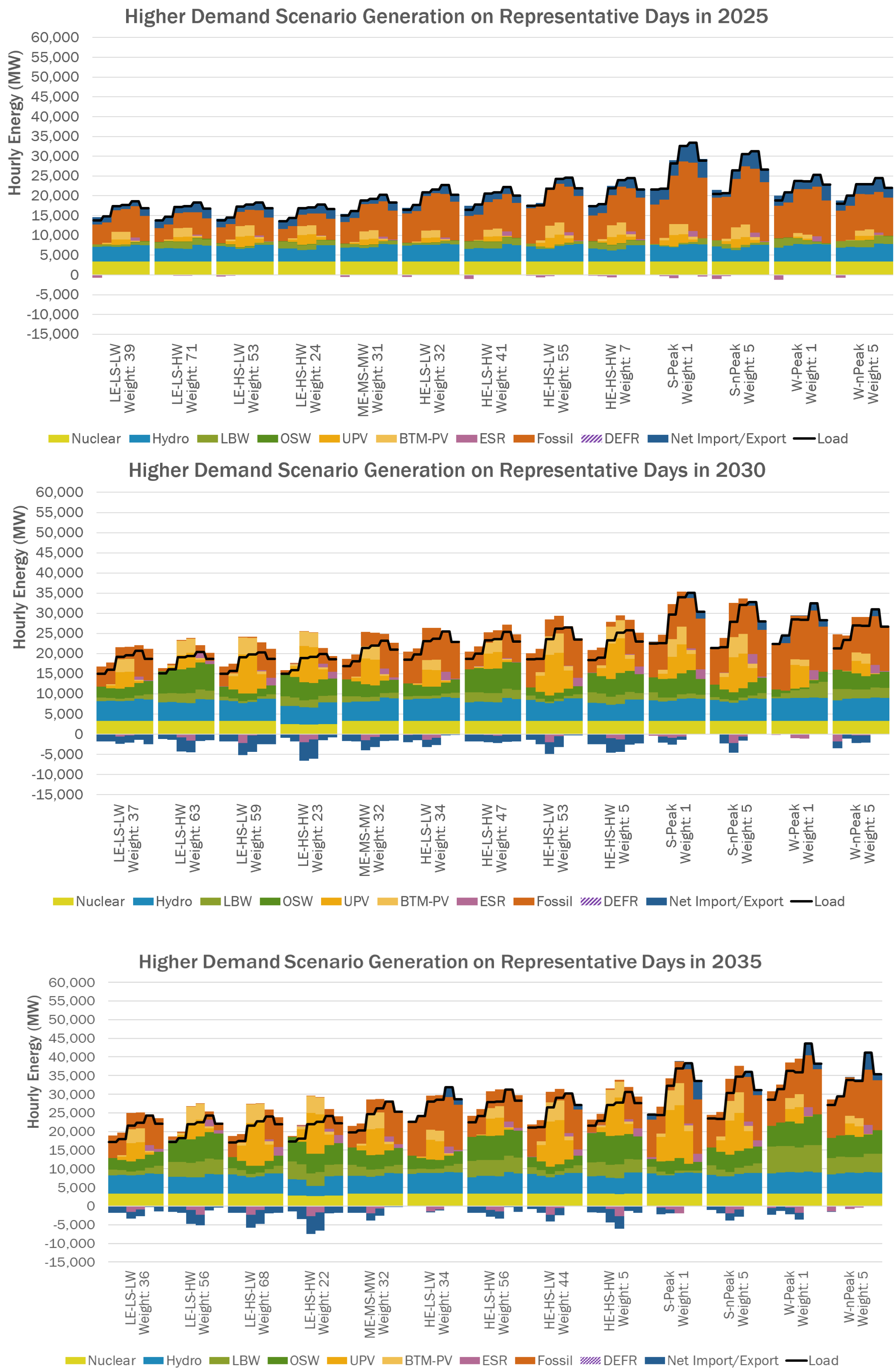
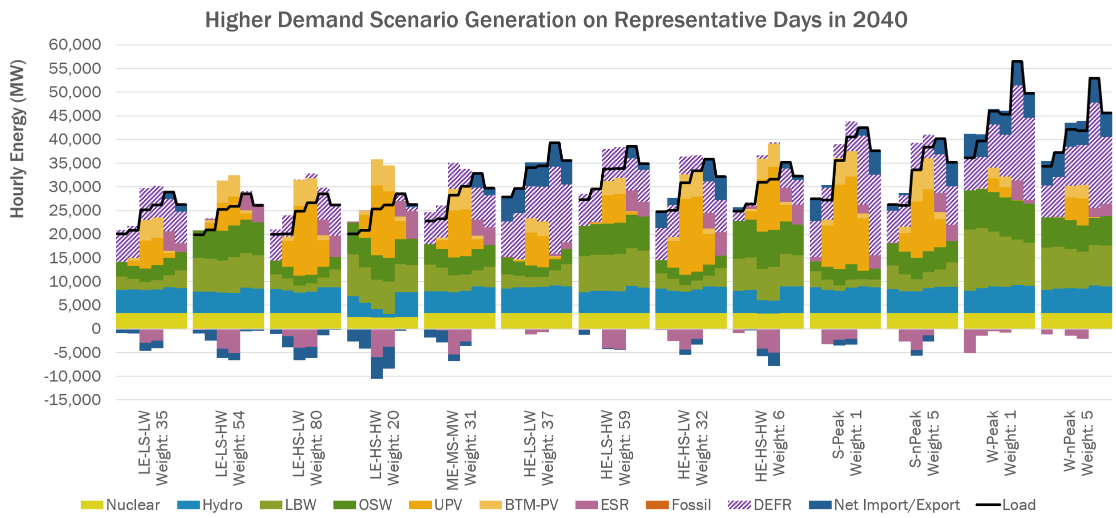


Figure H-10: Higher Demand Scenario Generation on Representative Days by Year





State Scenario Capacity Expansion Results

Preliminary results specific to the State Scenario in the Policy Case are included in Figures H-11 through H-13 for the No Headroom Case and Figures H-14 through H-17 for the 15% Compounding Headroom Cost Case.

There are several assumptions within the State Scenario that differ from the Lower and Higher Demand scenarios and that impact the resulting generation and capacity mix. The most impactful assumption change is that the DEFR technology within the State Scenario is specifically defined as hydrogen-powered combustion turbines, including both simple cycle and combined cycle configurations. Because of this assumption, the State Scenario results show a higher reliance on alternative technologies that have lower operating costs due to the high operating costs assumed for hydrogen-powered DEFRs and the increased load due to electrolysis needed to support the hydrogen-powered generators. In addition to LBW, which was discussed in a prior section, the State Scenario results also show a much higher reliance on UPV in combination with ESR. While solar is limited to daylight hours, the representative days figures below (Figure H-17), specifically in 2040, show that UPV is complimentary to ESR charging, electrolysis (primarily from "rest of economy" demand[6]), and flexible EV charging—all of which the model can optimize by choosing when to charge and/or serve these loads. The model finds it optimal to meet these "flexible" loads during the daytime when solar generation is high.

Because of the high energy needs in the State Scenario, which is similar to the energy demand in the Higher Demand scenario, the results show a need for additional OSW capacity above the 9 GW minimum requirement to meet the demand, despite its higher capital cost. It is important to

[6] See Integration Analysis Scenario 2.

consider that this increase in OSW capacity, and subsequent generation, is primarily driven by an assumed annual build limit on new solar capacity.

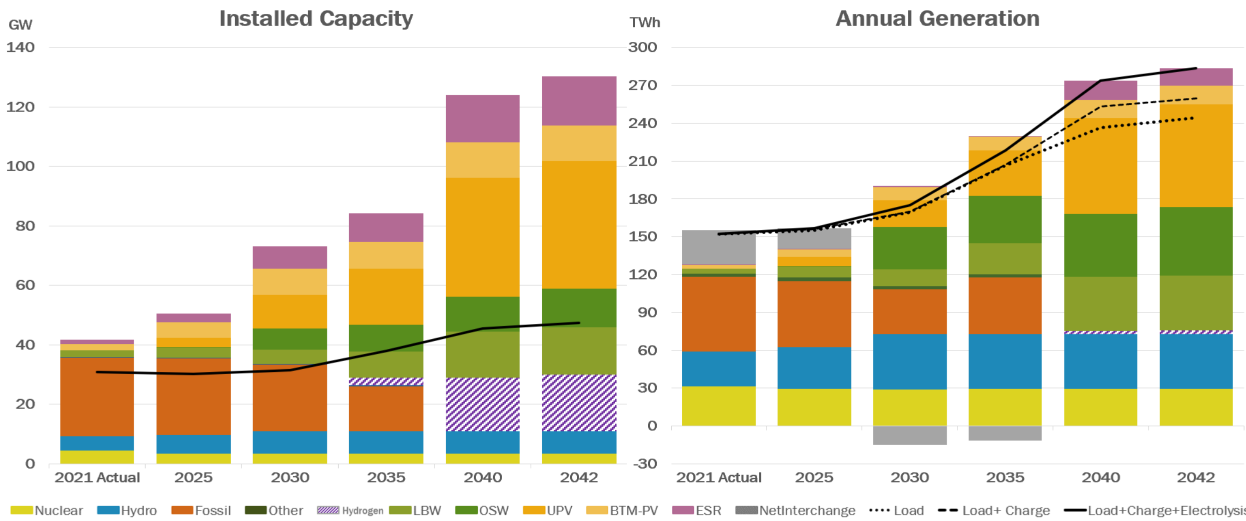
Regarding the distribution of both candidate and awarded resources between upstate (Zones A-F) and downstate (Zones G-K) in Figure H-12 and Figure H-15, the results show a high concentration of LBW, UPV, and ESR in upstate by 2040, while OSW, hydrogen-powered DEFR, and additional ESR are primarily concentrated downstate.

Figure H-13 and Figure H-16 shows capacity distribution at a zonal level for both State Scenario cases. In the No Headroom Case, the results show a significant level of UPV capacity in Zone E. This result is driven by the low build cost of UPV, represented at the county level, that is assumed for Zone E compared to other zones in this case.[7] In the 15% Compounding Headroom Cost Case, driven by the compounding cost of headroom in addition to the resource build cost, the results show a broader distribution of UPV capacity among the zones in upstate. As mentioned earlier, while the distribution of resources changes between these cases, the 2042 capacity mix at the NYCA level is roughly the same. While the cost associated with headroom in the 15% Compounding Headroom Cost Case is an approximation, this change in zonal distribution between cases highlights the importance of considering incremental costs associated with significant renewable generation builds in an area in capacity expansion modeling. Headroom, its associated costs, and its impact on capacity expansion will be further studied in the CGPP.

Figure H-17 shows generation characteristics of the resources in the 15% Compounding Headroom Cost Case. The results show that hydrogen-powered DEFR primarily generates during peak system conditions both in winter and summer and when renewable output, particularly solar, is low. However, compared to the DEFR options in the Higher and Lower Demand scenarios, hydrogen-powered DEFRs in the State Scenario run even less due to their high operating cost and their constraint that requires additional electrolysis load within the year if utilized. In addition, ESR provides generation support as solar resources ramp up or down in morning and evening periods. Flexible EV charging load also helps to reduce demand during peak periods. Because this flexible load capability contributes to the NYCA system as firm capacity, it also reduces the need for other generation resources.

[7] 100% of Zone E UPV is selected for the Jefferson, Lewis, and St. Lawrence county level aggregate costs.

Figure H-11: State Scenario Capacity Expansion Model Results – No Headroom Case



Capacity (Summer MW)	2021	2025	2030	2035	2040	2042
Nuclear	4,378	3,342	3,342	3,342	3,342	3,342
Fossil	26,345	25,753	22,424	15,022	-	-
Hydrogen - New CC	-	-	-	-	-	-
Hydrogen - New CT	-	-	-	-	3,062	3,244
Hydrogen - Retrofit CC	-	-	-	-	10,273	11,183
Hydrogen - Retrofit CT	-	-	-	2,676	4,558	4,558
Hydro	4,868	6,294	7,544	7,665	7,665	7,665
LBW	2,227	3,291	4,815	8,658	15,549	15,819
OSW	-	136	6,990	9,000	11,809	13,048
UPV	32	3,135	11,265	18,963	39,903	42,903
BTM-PV	2,116	5,384	8,972	8,973	12,019	12,019
Storage	1,405	2,905	7,405	9,678	15,729	16,503
Total	41,686	50,562	73,080	84,299	123,909	130,285
Annual Peak (MW)	30,397	29,568	29,861	37,047	45,062	47,046

Generation (GWh)	2021	2025	2030	2035	2040	2042
Nuclear	31,609	29,276	29,174	29,191	29,315	29,208
Fossil	59,154	52,440	35,452	44,927	-	-
Hydrogen - New CC	-	-	-	-	-	-
Hydrogen - New CT	-	-	-	-	9	3
Hydrogen - Retrofit CC	-	-	-	-	2,330	2,896
Hydrogen - Retrofit CT	-	-	-	-	3	8
Hydro	27,379	33,263	43,608	43,615	43,667	43,493
LBW	4,024	8,747	13,423	24,279	43,158	43,718
OSW	-	549	33,182	37,613	49,508	54,421
UPV	51	6,987	21,380	36,059	76,089	81,473
BTM-PV	2,761	5,871	10,610	10,812	14,589	14,648
Storage	355	903	532	662	15,171	13,739
Total Generation	127,930	140,771	191,192	232,425	278,392	288,901
RE Generation	34,570	56,320	122,736	153,041	242,182	251,491
ZE Generation	66,179	85,596	151,910	182,232	273,840	283,606
Net Interchange	27,222	16,060	(15,011)	(11,568)	-	-
Load	151,979	154,839	169,374	206,351	236,258	244,484
Load+Charge	152,334	155,837	169,837	206,958	253,100	259,634
Load+Charge+Electrolysis	152,334	156,730	175,110	218,349	273,840	283,606
Load Flexed by EV's	-	100	1,070	2,508	4,553	5,295
% RE [RE/Load+Charge]	23%	36%	70%	70%	88%	89%
% ZE [ZE/(Load+Charge)]	43%	55%	87%	83%	100%	100%

Emissions (million tons)	2021	2025	2030	2035	2040	2042
CO_2 Emissions	22.24	22.17	14.86	18.98	-	-

* Storage includes Pumped Storage Hydro and Batteries
* Utility solar (UPV) includes existing (77 MW) and new UPV
* Hydro includes hydro imports from Hydro Quebec
* Land-Based Wind (LBW), Offshore Wind (OSW), Zero Emissions (ZE)
* Dispachable Emission Free Resource (DEFR)
* Net Interchange is reported relative to New York (imports +, exports -)

Figure H-12: State Scenario Upstate Vs Downstate Cumulative Capacity Additions – No Headroom Case

Capacity Additions (MW)	2025		2030		2035		2040		2042	
	A-F	G-K	A-F	G-K	A-F	G-K	A-F	G-K	A-F	G-K
UPV	1,667	40	10,937	40	21,623	40	35,318	3,157	38,318	3,157
LBW	340	0	1,071	0	2,779	107	12,425	267	12,601	267
OSW	0	0	0	6,854	0	8,864	0	11,522	0	12,809
Hydrogen	0	0	0	0	0	2,676	5,426	12,467	5,426	13,559
Storage	1,450	0	4,960	990	4,960	3,263	7,205	7,030	7,205	7,803

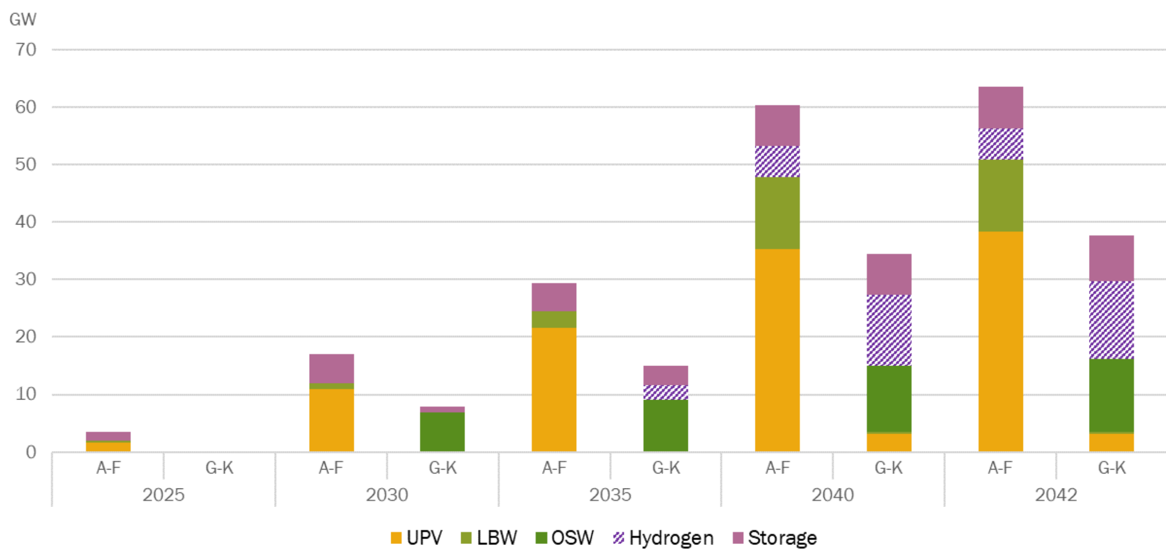


Figure H-13: State Scenario Cumulative Capacity Additions by Zone - No Headroom Case

Capacity Additions (MW)	2042										
	A	B	C	D	E	F	G	H	I	J	K
UPV	2,545	1,275	1,650	1,611	24,747	6,490	2,646	0	0	0	511
LBW	2,300	1,067	2,631	453	4,761	1,389	267	0	0	0	0
OSW	0	0	0	0	0	0	0	0	0	7,642	5,167
Hydrogen	392	110	1,283	336	199	3,107	2,741	1,091	1,220	5,835	2,672
Storage	40	183	1,975	1,957	2,117	933	0	0	0	6,133	1,670

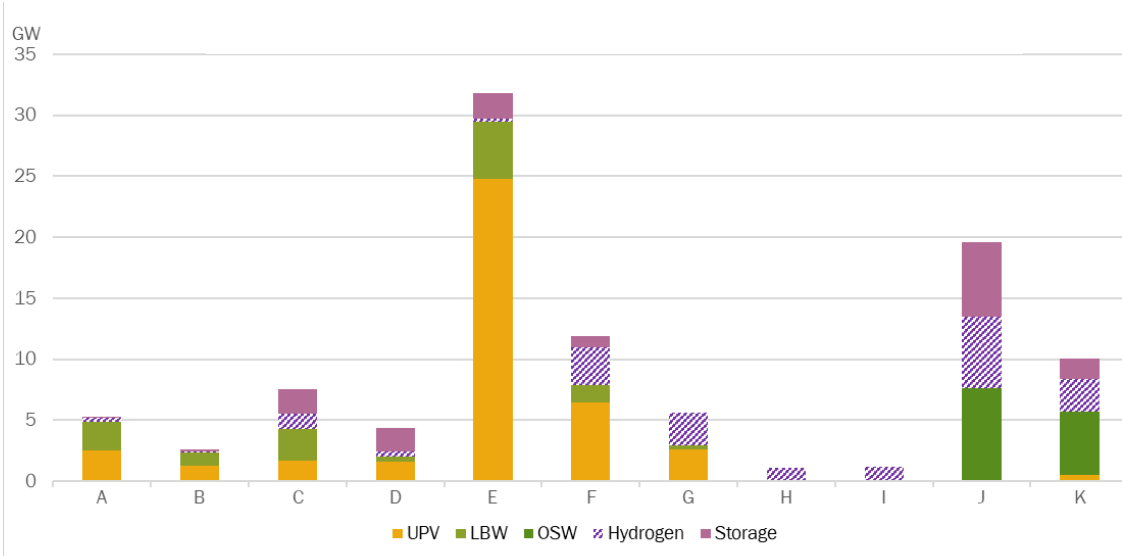
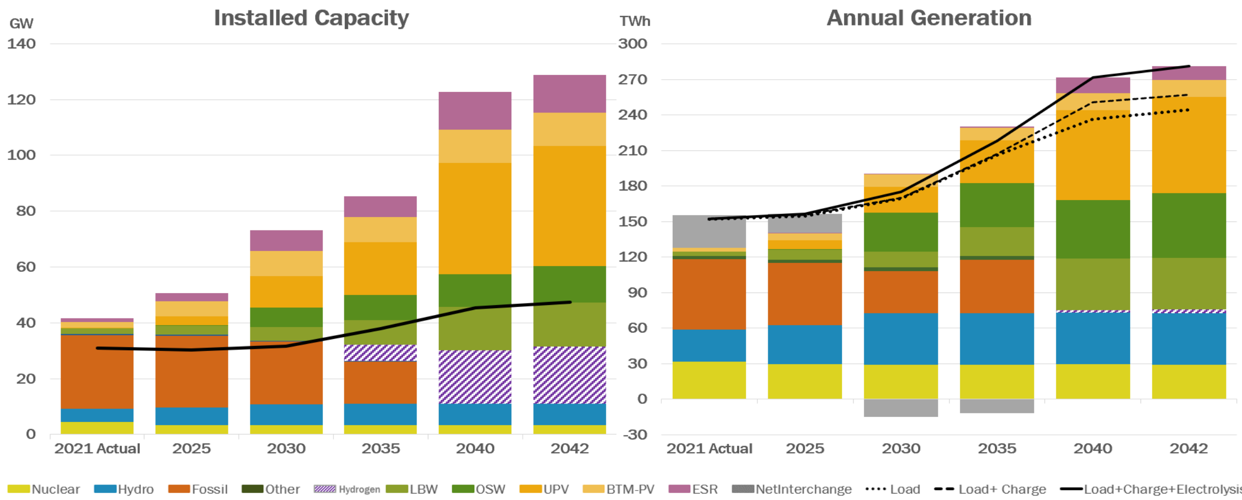


Figure H-14: State Scenario Capacity Expansion Model Results – 15% Compounding Headroom Cost Case



Capacity (Summer MW)	2021	2025	2030	2035	2040	2042
Nuclear	4,378	3,342	3,342	3,342	3,342	3,342
Fossil	26,345	25,753	22,424	15,022	-	-
Hydrogen - New CC	-	-	-	-	-	-
Hydrogen - New CT	-	-	-	-	3,062	3,244
Hydrogen - Retrofit CC	-	-	-	-	10,273	11,183
Hydrogen - Retrofit CT	-	-	-	2,676	4,558	4,558
Hydro	4,868	6,294	7,544	7,665	7,665	7,665
LBW	2,227	3,291	4,815	8,658	15,549	15,819
OSW	-	136	6,990	9,000	11,809	13,048
UPV	32	3,135	11,265	18,963	39,903	42,903
BTM-PV	2,116	5,384	8,972	8,973	12,019	12,019
Storage	1,405	2,905	7,405	9,678	15,729	16,503
Total	41,686	50,562	73,080	84,299	123,909	130,285
Annual Peak (MW)	30,397	29,568	29,861	37,047	45,062	47,046

Generation (GWh)	2021	2025	2030	2035	2040	2042
Nuclear	31,609	29,276	29,174	29,191	29,315	29,208
Fossil	59,154	52,440	35,452	44,927	-	-
Hydrogen - New CC	-	-	-	-	-	-
Hydrogen - New CT	-	-	-	-	9	3
Hydrogen - Retrofit CC	-	-	-	-	2,330	2,896
Hydrogen - Retrofit CT	-	-	-	-	3	8
Hydro	27,379	33,263	43,608	43,615	43,667	43,493
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UPV	51	6,987	21,380	36,059	76,089	81,473
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Storage	355	903	532	662	15,171	13,739
Total Generation	127,930	140,771	191,192	232,425	278,392	288,901
RE Generation	34,570	56,320	122,736	153,041	242,182	251,491
ZE Generation	66,179	85,596	151,910	182,232	273,840	283,606
Net Interchange	27,222	16,060	(15,011)	(11,568)	-	-
Load	151,979	154,839	169,374	206,351	236,258	244,484
Load+Charge	152,334	155,837	169,837	206,958	253,100	259,634
Load+Charge+Electrolysis	152,334	156,730	175,110	218,349	273,840	283,606
Load Flexed by EV's	-	100	1,070	2,508	4,553	5,295
% RE [RE/Load+Charge]	23%	36%	70%	70%	88%	89%
% ZE [ZE/(Load+Charge)]	43%	55%	87%	83%	100%	100%

Emissions (million tons)	2021	2025	2030	2035	2040	2042
CO_2 Emissions	22.24	22.17	14.86	18.98	-	-

* Storage includes Pumped Storage Hydro and Batteries
* Utility solar (UPV) includes existing (77 MW) and new UPV
* Hydro includes hydro imports from Hydro Quebec
* Land-Based Wind (LBW), Offshore Wind (OSW), Zero Emissions (ZE)
* Dispachable Emission Free Resource (DEFR)
* Net Interchange is reported relative to New York (imports +, exports -)

Figure H-15: State Scenario Upstate Vs Downstate Cumulative Capacity Additions – 15% Compounding Headroom Cost Case

Capacity Additions (MW)	2025		2030		2035		2040		2042	
	A-F	G-K	A-F	G-K	A-F	G-K	A-F	G-K	A-F	G-K
UPV	1,667	40	9,797	40	17,495	40	35,318	3,157	38,318	3,157
LBW	340	0	1,864	0	5,528	179	12,331	267	12,601	267
OSW	0	0	0	6,854	0	8,864	0	11,673	0	12,912
Hydrogen	0	0	0	0	0	2,676	4,995	12,898	5,426	13,559
Storage	1,450	0	4,960	990	4,960	3,263	7,927	6,347	7,960	7,088

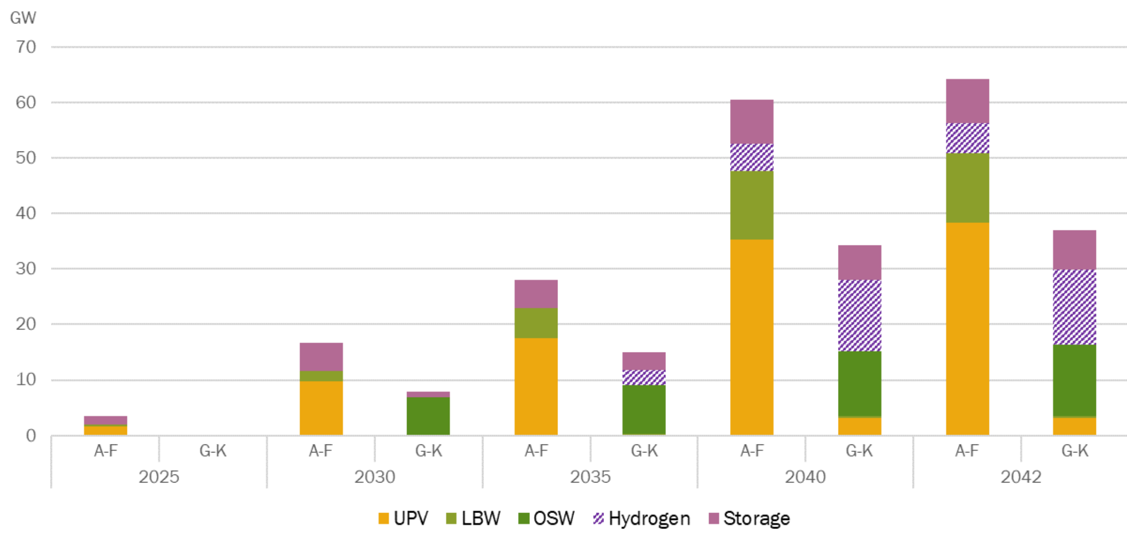


Figure H-16: State Scenario Cumulative Capacity Additions by Zone - 15% Compounding Headroom Cost Case

Capacity Additions (MW)	2042										
	A	B	C	D	E	F	G	H	I	J	K
UPV	4,940	2,751	5,299	2,587	13,789	8,952	2,646	0	0	0	511
LBW	2,300	1,067	2,631	453	4,761	1,389	267	0	0	0	0
OSW	0	0	0	0	0	0	0	0	0	7,642	5,270
Hydrogen	392	110	1,283	336	199	3,107	2,718	1,071	1,263	5,835	2,672
Storage	345	1,019	1,441	445	3,219	1,491	0	0	0	6,133	955

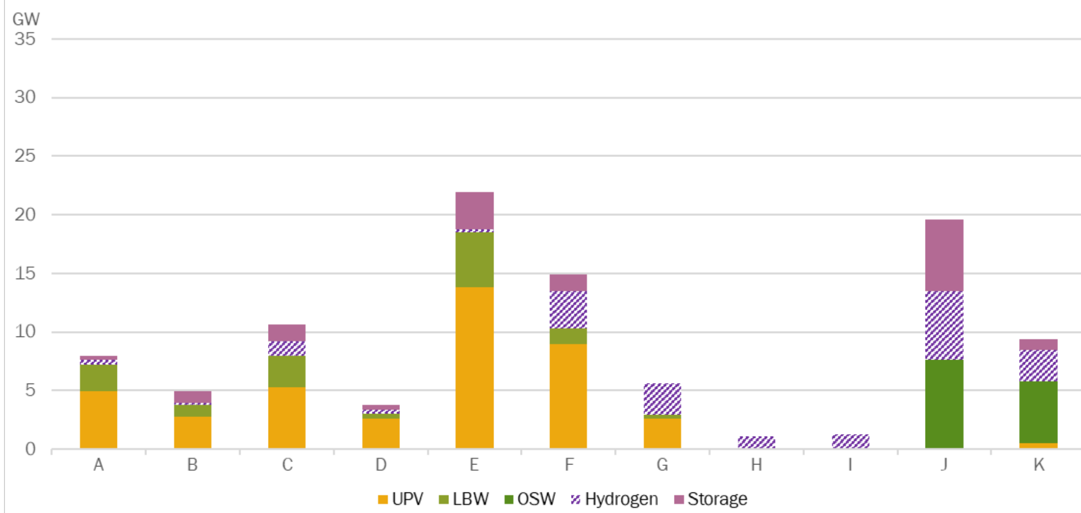
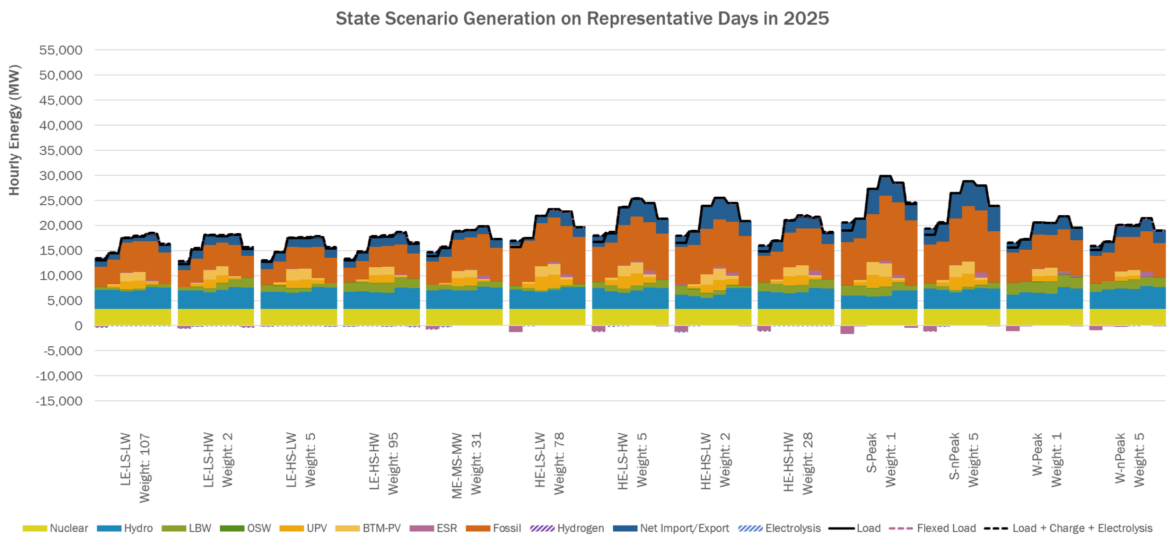
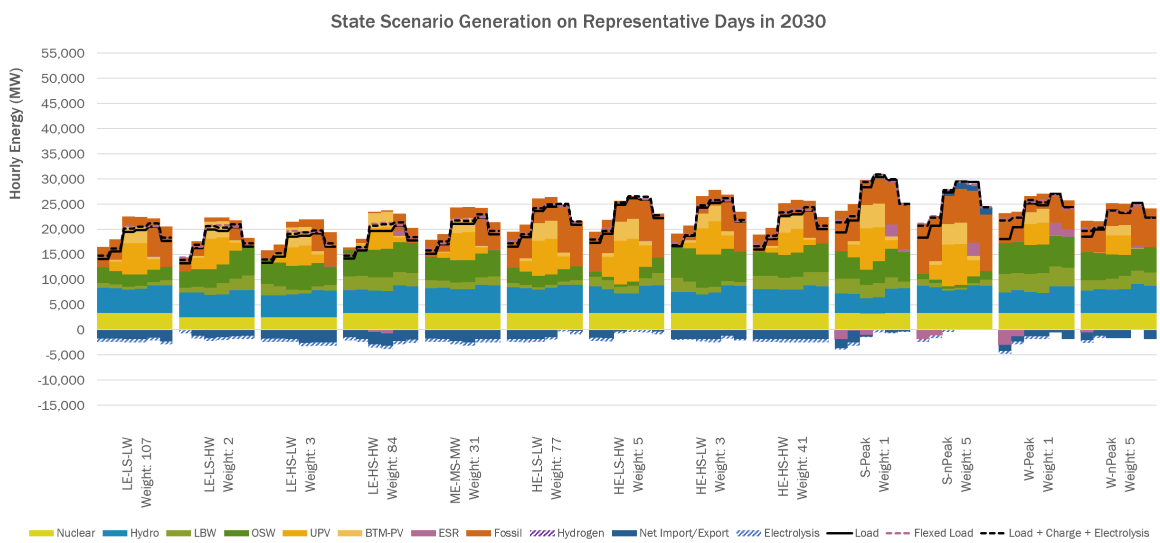
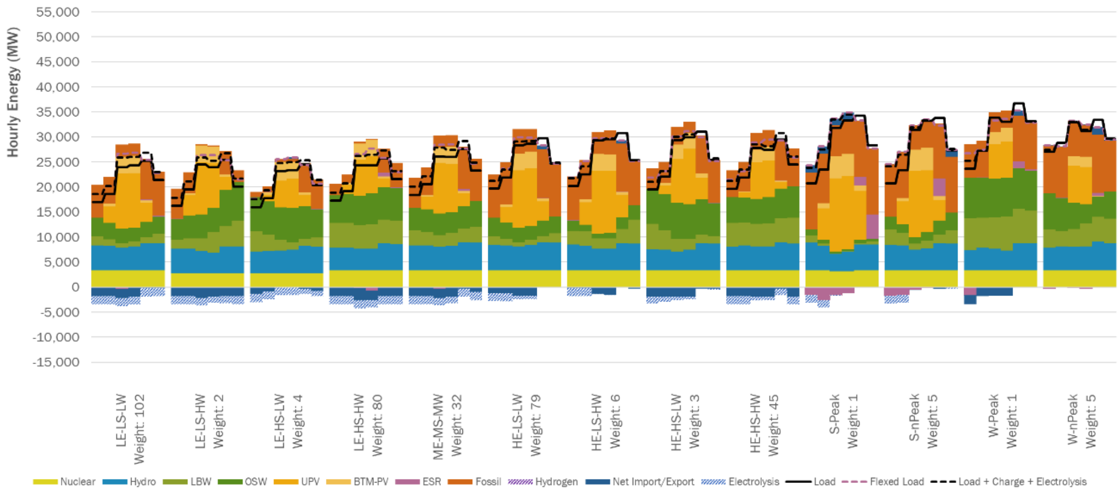


Figure H-17: State Scenario Generation on Representative Days by Year - 15% Compounding Headroom Cost Case





State Scenario Generation on Representative Days in 2035



State Scenario Generation on Representative Days in 2040