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Filling the Gap in New York's Decarbonization Plan: A New View of the Electric Grid

Leonard Rodberg, PhD[1], Reiner Kuhr[2], and Ahmad Nofal[3]

Executive Summary

New York State has seriously underestimated the need for a large firm dispatchable source* in its future decarbonized grid. The growth in demand from the expected electrification of automobiles and the heating of buildings requires that such a resource operate for more than a third of the year to provide a grid that is reliable and avoids rolling blackouts.

We have analyzed a Renewable-Focused Plan (RFPlan) with characteristics similar to scenarios describing the state's future electric grid prepared by the NYS Energy Research and Development Authority (NYSERDA) for the Climate Action Council. (CAC). Using a new modeling tool that allows an hour-by-hour analysis of electric system behavior, we can see details of the hourly operation of each energy source, features not disclosed by existing models, including that used by NYSERDA. We can also estimate the cost to the purchasers of electricity and taxpayers of these scenarios.

The State's Climate Leadership and Community Protection Act (CLCPA) requires that the electric grid be free of greenhouse gas emissions by 2040. NYSERDA's scenarios create a plan which depends almost entirely on generating electricity with renewable sources. They retain existing nuclear plants, but no new ones are added.

The Scoping Plan adopted by the CAC declares that "wind, water, and sunlight will power most of New York's economy." While its focus is on renewable sources, the CAC does recognize the need for an additional clean source: "plan analysis and current studies show that the 2040 zero-emission goal requires between 15 and 45 gigawatts (GW) of electric power from dispatchable zero-emission resources". However, NYSERDA finds that little more than 2% of the potential output of such a dispatchable emission-free resource (DEFR) will actually be used.

Simple arithmetic makes this seem highly questionable. By 2040, NYSERDA and NYISO, the grid operator, estimate that building and transportation electrification will have expanded so that the grid will have a peak load in winter of 46-50 GW. Yet, even with land-based and offshore wind blowing at full capacity, no more than 35 GW will be available during winter evenings. Little or no excess capacity exists to charge the batteries, and, of course, solar won't be available. Much more than 2% of the dispatchable source's potential output has to be available to get through the winter without blackouts.

Our hour-by-hour analysis shows that the firm dispatchable source has to run two-thirds of the year. The total load has increased from today. The summer peak has been replaced by a much higher winter peak. That greater demand is met by the extended operation of the DEFR which runs during most evenings in the cooler portion of the year. In fact, we find a capacity factor -- the fraction of potential output actually used -- of 14.4%. Our detailed results are shown below.

2040 Electricity Generation RFPlan

Source	Capacity MW	Output GWh/yr	Capacity Factor %	% Load
Existing Nuclear	3,355	27,104	92.2%	11.1
Hydro	4,612	28,619	70.8%	11.7
PV BTM	6,009	6,968	13.2%	2.8
PV Grid	34,154	32,100	10.7%	13.1
Onshore Wind	13,017	26,559	23.3%	10.8
Offshore Wind	14,400	56,274	44.6%	23.0
Battery Discharge	20,709	[8,338]	4.6%	[3.4]
DEFR	29,000	36,658	14.4%	15.0
NE/PJM Purchase		9,082		3.7
Canada Purchases		21,080		8.6
Load		245,171		100.0

In this paper we suggest alternatives to NYSERDA's plan that use baseload nuclear power along with a nuclear-powered firm dispatchable resource (DEFR) to ensure a reliable grid. Our plan costs one-third less than the RFPlan.

* A firm dispatchable source is always available and able to supply whatever additional electric output is needed.

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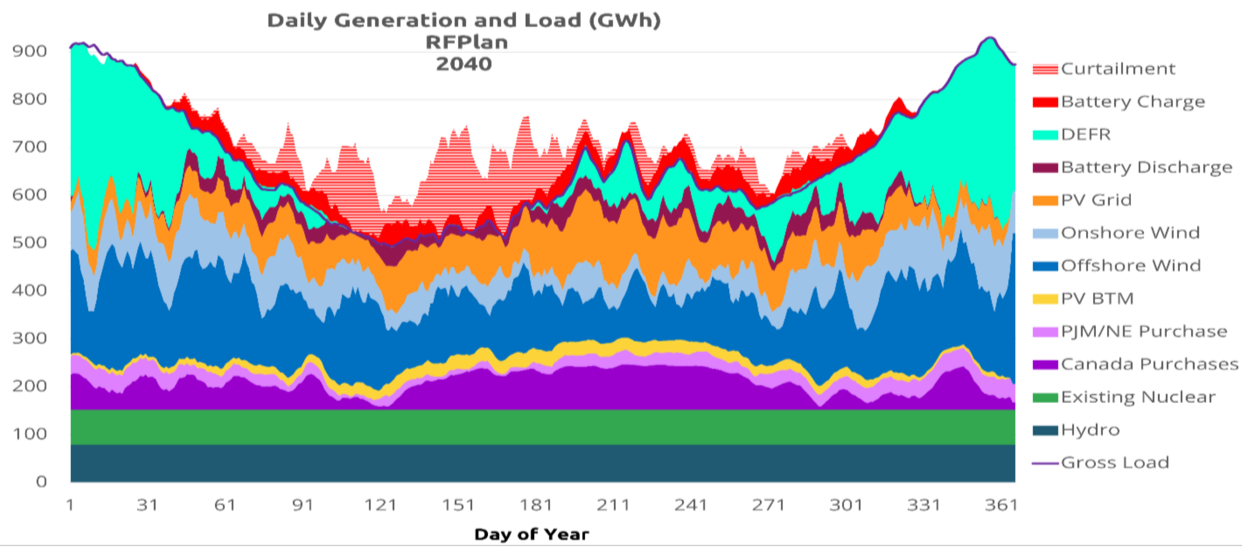

Overview

We have analyzed a Renewable-Focused Plan (RFPlan) for decarbonizing New York's electric grid using a new modeling tool that allows an hour-by-hour analysis of grid behavior. This model reveals important features of the grid not disclosed by existing models, including the model used by the New York State Energy Research and Development Authority (NYSERDA) in its scenario analysis for the State's Climate Action Council (CAC). The new model provides extensive quantitative information such as costs to ratepayers and taxpayers, as well as details of the operation of each energy source.

Our findings suggest that previous analyses have seriously underestimated the need for large firm dispatchable emission-free resources – ones that are always available and able to support whatever additional electric load is present. Due to the expected electrification of automobiles and the heating of buildings, we find that such a resource must operate for more than a third of the year if the state is to have a grid that is reliable and avoids rolling blackouts. Among existing technologies, only nuclear power can meet this need at the scale required by 2040. We present alternate plans that will cost less and avoid a vast expansion of solar, wind, and storage. Our alternate scenarios use additional baseload nuclear power and better match the projected electricity demand.

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[3] Center for Academic Collaborative Initiatives, ahmad_nofal@centeraci.com. Mr. Nofal is the co-developer of the CACI Market and Technology Models.

This report represents the views of the authors and does not necessarily represent the views of Nuclear New York or its supporters.

Introduction: Renewables and the winter energy deficit

The Climate Leadership and Community Protection Act (CLCPA) the New York State Legislature passed in 2019. The legislation mandates that the State's electrical supply be free of greenhouse gas emissions by 2040. Responding to that directive, NYSERDA has, over the past two years, modeled four scenarios for the State's Climate Action Council, all of which expand only renewable generation sources.[4,5] The Scoping Plan adopted by the State's Climate Action Council declares that "wind, water, and sunlight will power most of New York's economy." Although the Scoping Plan refers to the possibility of including nuclear power,[6] the quantitative scenario description (the "Integration Analysis") that accompanies the Scoping Plan omits any expansion of nuclear capacity. It retains existing nuclear plants, which meet 17% of today's load, saving New Yorkers money while preventing greenhouse gas emissions.

While its focus has been on the renewable sources, the Climate Action Council's Scoping Plan recognizes the need for an additional, dispatchable source. It declares that "Scoping Plan analysis and current studies show that the 100x40 goal requires 15 gigawatts (GW) to 45 GW of electricity from zero-emission, dispatchable resources in 2040….Addressing this gap will require identifying and developing solutions for dispatchable technologies, like storage or nuclear power, that can be called on as needed to balance supply and demand."[7] New York Independent System Operator (NYISO), the grid operator too believes, the state requires 27 and 45 GW of electric power from dispatchable zero-emission resources to meet the demand at that point and maintain reliability".[8] The Scoping Plan does not specify what that source will be, though it does propose using hydrogen produced with renewable sources as a fuel for such a source.

The following table shows the results NYSERDA presented for its Scenario 3, the most frequently discussed of four modeled scenarios.[9] Most remarkably, NYSERDA's model finds little more than 2% of the potential output (capacity factor) of a dispatchable emissions-free resource (DEFR) will be used. Simple arithmetic makes this seem highly questionable. NYSERDA estimates that, by 2040, building and

[4] https://climate.ny.gov/-/media/project/climate/files/NYS-Climate-Action-Council-Final-Scoping-Plan-2022.pdf

[5] We will use the word "renewable," since it is in widespread common usage. However, it is a misleading term. While the sources of energy, principally the sun and wind, are for practical purposes inexhaustible, the equipment on which they depend has limited lifetimes and must be replaced at least every 20-25 years. Furthermore, most of the materials embodied in them cannot be recycled economically or environmentally responsibly.

[6] https://www.nyserda.ny.gov/-/media/Project/Climate/Files/2021-11-18-Integration-Analysis-Initial-Results-Presentation.pdf

[7] P.13, https://climate.ny.gov/-/media/project/climate/files/NYS-Climate-Action-Council-Final-Scoping-Plan-2022.pdf

[8] https://www.nyiso.com/documents/20142/32663964/2021-2040_System_Resource_Outlook_Report_DRAFT_v15_ESPWG_Clean.pdf/99fb4cbf-ed93-f32e-9acf-ecb6a0cf4841

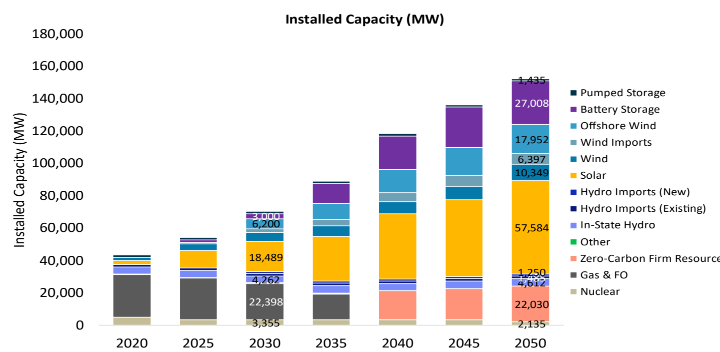
[9] NYSERDA Integration Analysis, September 2023 update. https://www.nyserda.ny.gov/-/media/Project/Nyserda/Files/Publications/Energy-Analysis/IA-Annex-2-Key-Drivers-and-Outputs-2022-revised.xlsx

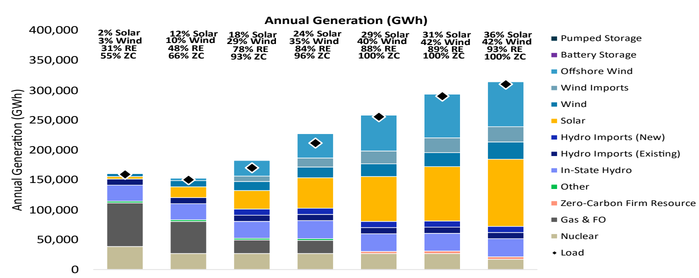
transportation electrification will have expanded so that the State's electric load will peak in the winter with a maximum load of 46-50 GW.[10] In winter, there is little or no excess solar generating capacity to charge batteries, and in the evenings, of course, there is no solar output. Further, imports of power from neighboring states and Canada are not guaranteed. NYISO observes that "NERC's [North American Electric Reliability Corp] 2023 Summer Reliability Assessment identifies reduced supply reserve margins in regions neighboring the NYISO in its risk analysis. These reduced margins potentially limit the ability to import electricity from neighboring regions, putting greater importance on available supply and transmission within New York."[11] And the states neighboring New York tend to have the same weather patterns as New York, limiting their ability to cover the inability of New York's in-state generators to meet the demand.

The maximum in-state output in the evenings will occur at a time when both onshore and offshore wind are operating at full capacity, so the total capacity will be just 35 GW. This leaves a wintertime gap at peak load of at least 11 GW and, much of the time, far more. To overcome this deficit on evenings throughout the winter, the dispatchable source will have to fill the gap, or there will be frequent, rolling blackouts.

NYSERDA Scenario 3

2040 Electricity Generation NYSERDA Scenario 3 (Integration Analysis, 15 September 2023)			
Source	**Capacity MW**	**Output GWh/yr**	**Capacity Factor %**
Existing Nuclear	3,355	26,452	90.0%
Hydro	4,612	29,716	73.5%
Solar	40,163	75,391	21.4%
Onshore Wind	7,573	20,892	31.5%
Offshore Wind	14,400	60,043	47.6%
DEFR	17,788	3,414	2.2%
Wind Imports	5,444	21,417	44.9%
Hydro Imports	2,735	20,763	86.7%
Battery Storage	22,144	(2,396)	-
Imports		11,236	
Exports		(11,236)	
Load		255,693	





[10] ibid.

[11] https://www.nyiso.com/documents/20142/2223020/2023-Power-Trends.pdf

An hour-by-hour analysis of New York's future electric grid

NYSERDA has not explained how it derived its results. The first column in its Scenario 3 shows the rated *capacity* of each source in the plan in megawatts (MW). The calculated electricity *generated* each year in gigawatt-hours (GWh) from each source is shown in the second column. NYSERDA has not disclosed the operational logic that links the output energy (GWh) to the input power (MW). It has disclosed neither the underlying assumptions for resource dispatch to match electric supply with demand, nor the nature and timing of imports and exports, nor what the proposed plan will cost purchasers of electricity and the State's taxpayers. It provides only the output of each source for the entire year.

To fill this critical information gap, we have used a model that performs an hour-by-hour analysis of the projected electricity demand in 2040 to show how the in-state sources assumed in NYSERDA's scenario actually behave when serving this varying demand. Electric demand in 2040 is based on NYISO's projections.[12] While based on NYSERDA's Scenario 3, RFPlan has material differences due to gaps in knowledge that remain unanswered by NYSERDA.[13,14] In order to eliminate blackouts, the DEFR capacity has to be increased to 29 GW. RFPlan includes the wind imports assumed by NYSERDA and treats them as land-based in-state wind. We do not attempt to model the extensive unspecified import and export energy in NYSERDA's model. Instead, we use the power that New York currently purchases from Canada and, as needed, from neighboring states, augmented by the expected capacity expansion of 1,250 MW from Canada via the Champlain Hudson Power Express (CHPE) presently under development.[15] Modeling constraints result in slightly different amounts of imports between the scenarios. This has a small effect on total system costs because imports are treated as free. While the installed capacities of in-state generation sources are taken from NYSERDA's Scenario 3, their energy production and resulting capacity factors are dynamically calculated by our simulator. To account for the weather's influence, the hourly solar and wind output is scaled using the hourly record for 2022.

Our grid simulator is the New York adaptation of the model developed for New England by Reiner Kuhr and Ahmad Nofal, experienced energy engineers and leaders at the Center for Academic

[12] https://www.nyiso.com/documents/20142/2226333/2023-Gold-Book-Public.pdf

[13] See Appendix 2: Gaps in Knowledge in Bright Future: A More Reliable and Responsible Climate Plan for New York https://www.nuclearny.org/bright-future/ and "May 5 meeting follow-up/Integration Analysis questions" https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B9044358C-0000-CA10-8DFF-AE01BCECCB09%7D

[14] In its Integration Analysis, NYSERDA does not show its breakdown of PV BTM (rooftop solar) versus PV Grid (utility-scale solar). Instead, it categorizes solar as "Solar" or "Dist Solar." "Solar" represents PV Grid, and commentators are assuming half of "Dist Solar" will be grid-scale community solar. Thus, we treat half of "Dist Solar" as PV BTM and the rest as PV Grid.

[15] CHPE capacity is modeled as available throughout the year, when NYISO has warned of its unavailability during the winter, as the facility is not obligated to provide any capacity in the winter per the contract terms. The added capacity is modeled as scaling up of existing imports from Canada. https://www.nyiso.com/-/press-release-%7C-nyiso-report-highlights-risks-to-future-grid-reliability

Collaboration Initiatives (CACI).[16] The CACI approach uses spreadsheet software to calculate, for each hour throughout the year, how the available energy sources, including battery storage and the DEFR, will be used to meet projected electric load. When the non-dispatchable sources – hydro[17], baseload (always-on) nuclear, solar, and wind – are able to meet the load, any excess power is used to charge the batteries. If they are unable to meet the demand, batteries are called upon to fill the gap. The model calls upon the DEFR to meet the remaining load. (Appendix A details the workings of the CACI model.) To quantify the characteristics of the DEFR, in our modeling for all scenarios we approximate the parameters of Natrium, a small modular nuclear reactor (SMR) being developed by TerraPower and GE-Hitachi. The Natrium design integrates a 345 MW fast neutron reactor coupled with molten salt thermal storage capable of yielding an output of 500 MW for up to five-and-a-half hours.[18] The DEFR is treated as entirely dispatchable from 0 up to 500 MW. In order to cover the load for every hour of the year and avoid having any unmet load, we increased the size of the DEFR from NYSERDA's 18 GW to 29 GW.[19]

NYSERDA suggests, in its Integration Analysis, the use of hydrogen produced with renewable-generated electricity to fuel the DEFR. We have examined this case and find that supplying sufficient energy to produce the required hydrogen would necessitate a 40% increase in the number of solar and wind installations, beyond those envisioned in the RFPlan. We are unable to estimate that system's cost, since it would require creating a new infrastructure to produce, transport, and store a large supply of hydrogen during the summer for use in the winter. Analyzing such a construction project is beyond the scope of this study.

A firm dispatchable emission-free resource is needed for a large part of the year

Our base year, providing solar, wind, and load patterns, is 2022, before the large-scale expansion of intermittent renewables. The next figure shows the results of our analysis for every day of 2022. Table B-1 in Appendix B gives detailed quantitative results for this year. Appendix C shows the assumptions made for each of the energy sources. In the figure, one can see the baseload hydro and existing nuclear facilities, the purchase of power from neighboring states and Canada, and finally, the gas- and oil-burning plants meeting the rest of the varying load. Rooftop solar and land-based wind play a minor role.

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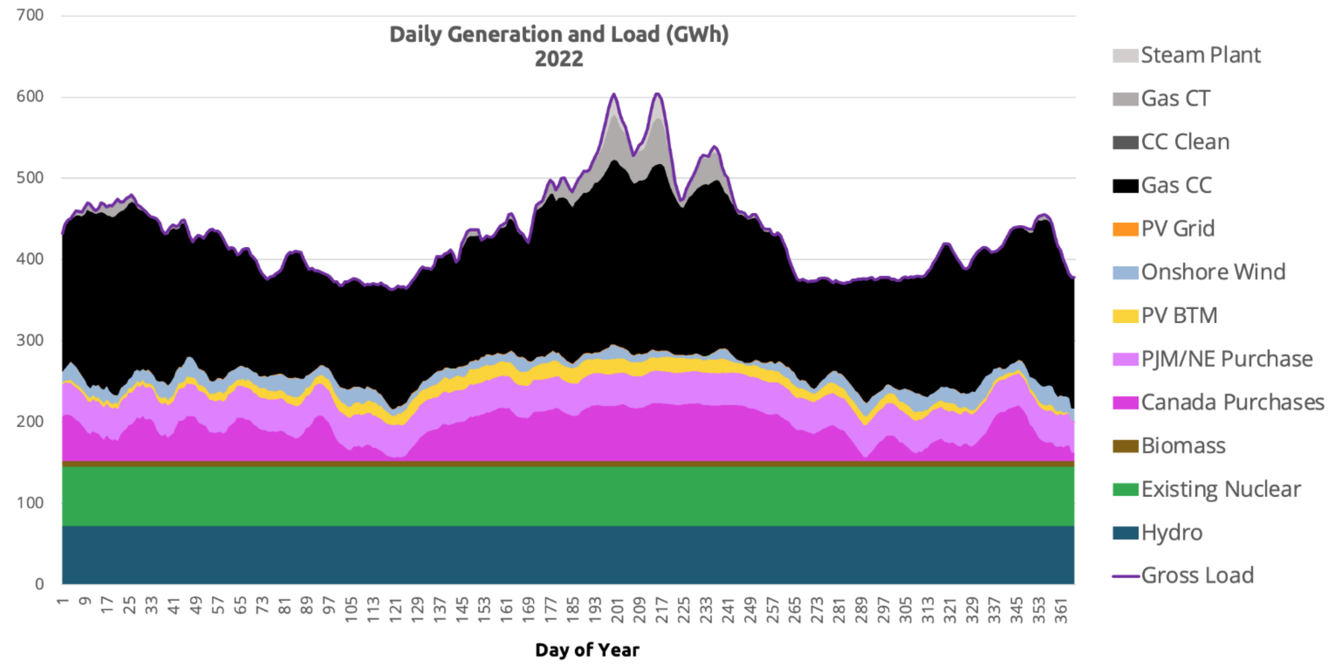
[16] https://centeraci.com/wp-content/uploads/2022/09/Technical-Economic-Limits-for-Renewable-Power-Integration-in-New-England-Full-Report-Rev-1.pdf

[17] Though hydro is used today to respond to some of the variation in system demand, for simplicity in this model it is treated as a non-dispatchable fixed resource.

[18] https://natriumpower.com/reactor-technology

[19] For an overview of the dispatchability of nuclear plants, see https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7BA0F5C88B-0000-C521-AAAD-996DCC98AF0F%7D

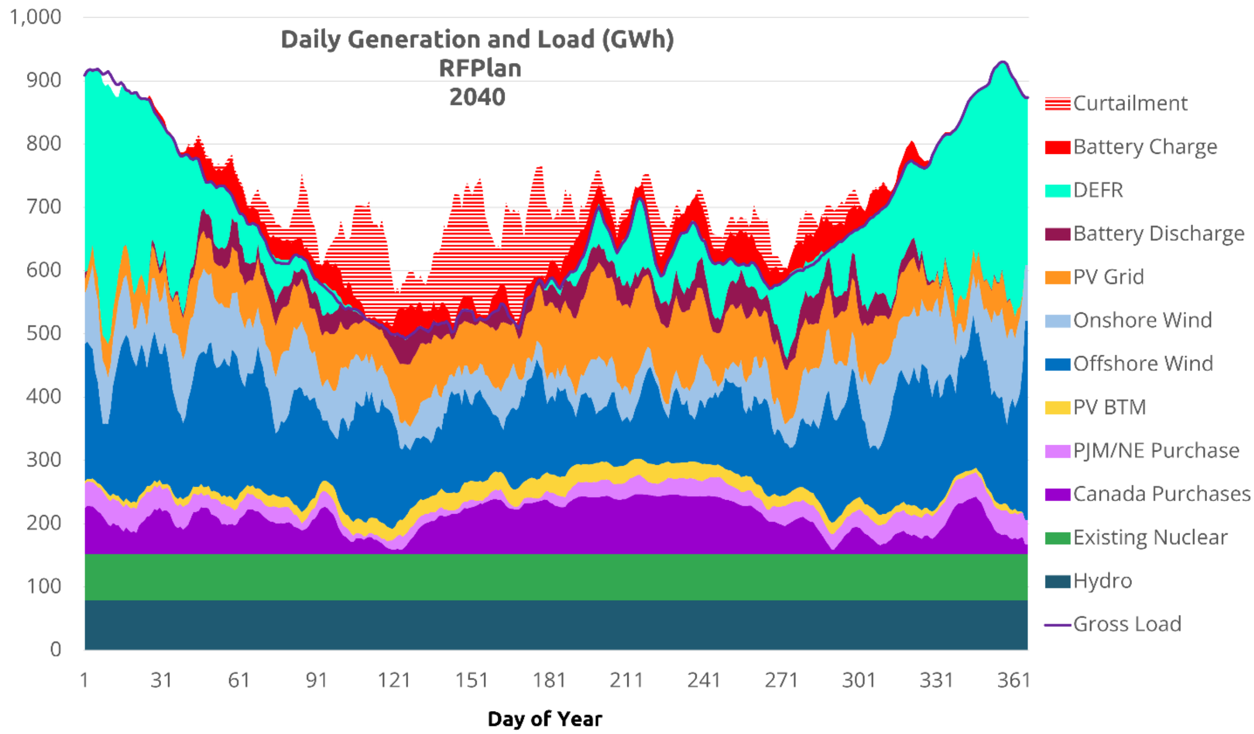


Note 1: Steam plant – Gas-or oil-fired boilers & steam turbine | Gas CT –gas-fired combustion turbines
Gas CC = gas-fired combined cycle plants | PV BTM = Solar PV behind-the-meter
Onshore Wind = Land-based wind power | Offshore Wind = Ocean-based wind power
PJM/NE Purchases = Imports from neighboring states | Canada Purchases = Imports from Canada
Biomass = Burning wood and municipal waste
Hydro = Power plants on Niagara and St. Lawrence Rivers
Existing Nuclear = Power plants on Lake Ontario

Note 2: All daily (annual) graphs are subject to 7-day smoothing to improve readability.

2022 Electricity Generation (Actual)				
Source	**Capacity MW**	**Output GWh/yr**	**Capacity Factor %**	**% Load**
Existing Nuclear	3,305	26,700	92.2%	16.8%
Hydro	4,265	26,487	70.9%	16.6%
PV BTM	3,760	4,360	13.2%	2.7%
PV Grid	154	179	13.2%	0.1%
Onshore Wind	2,191	4,867	25.4%	3.1%
Biomass	258	2,261	100.0%	1.4%
Gas CC	10,843	60,132	63.3%	37.8%
Gas CT	4,186	2,577	7.0%	1.6%
Steam Plants	10,637	539	0.6%	0.3%
NE and PJM Purchases		14,401		9.0%
Canada Purchases		16,090		10.1%
Load		159,186		100.0%
Total In-State Generation Cost: $88 per megawatt-hour (MWh)				

The table and figure below describe 2040 grid behavior under the RFPlan, when all electricity is to be emission-free. They show the contribution of each energy source in meeting the electric load from January 1 to December 31, 2040.[20]



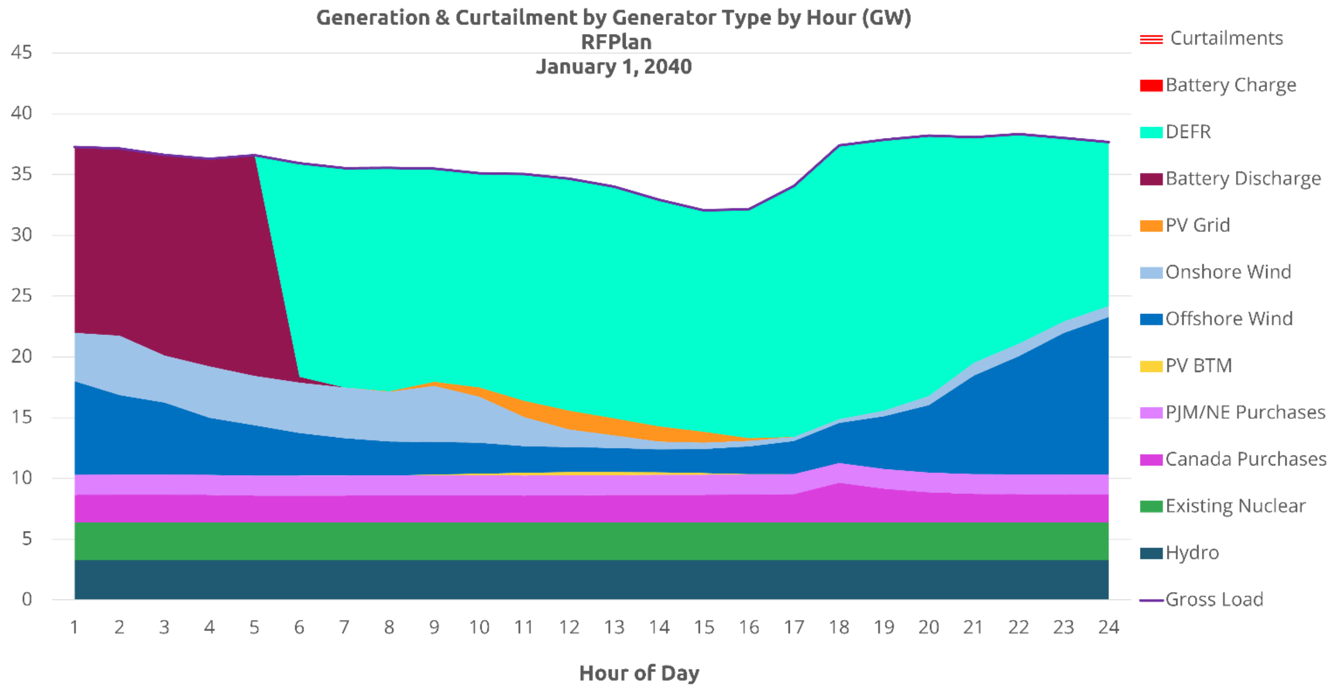
2040 Electricity Generation RFPlan				
Source	**Capacity MW**	**Output GWh/yr**	**Capacity Factor %**	**% Load**
Existing Nuclear	3,355	27,104	92.2%	11.1%
Hydro	4,612	28,619	70.8%	11.7%
PV BTM	6,009	6,968	13.2%	2.8%
PV Grid	34,154	32,100	10.7%	13.1%
Onshore Wind	13,017	26,559	23.3%	10.8%
Offshore Wind	14,400	56,274	44.6%	23.0%
Battery Discharge	20,709	[8,338][21]	4.6%	[3.4%]
DEFR	29,000	36,658	14.4%	15.0%
NE and PJM Purchases		9,082		3.7%
Canada Purchases		21,080		8.6%
Load		245,171		100.0%

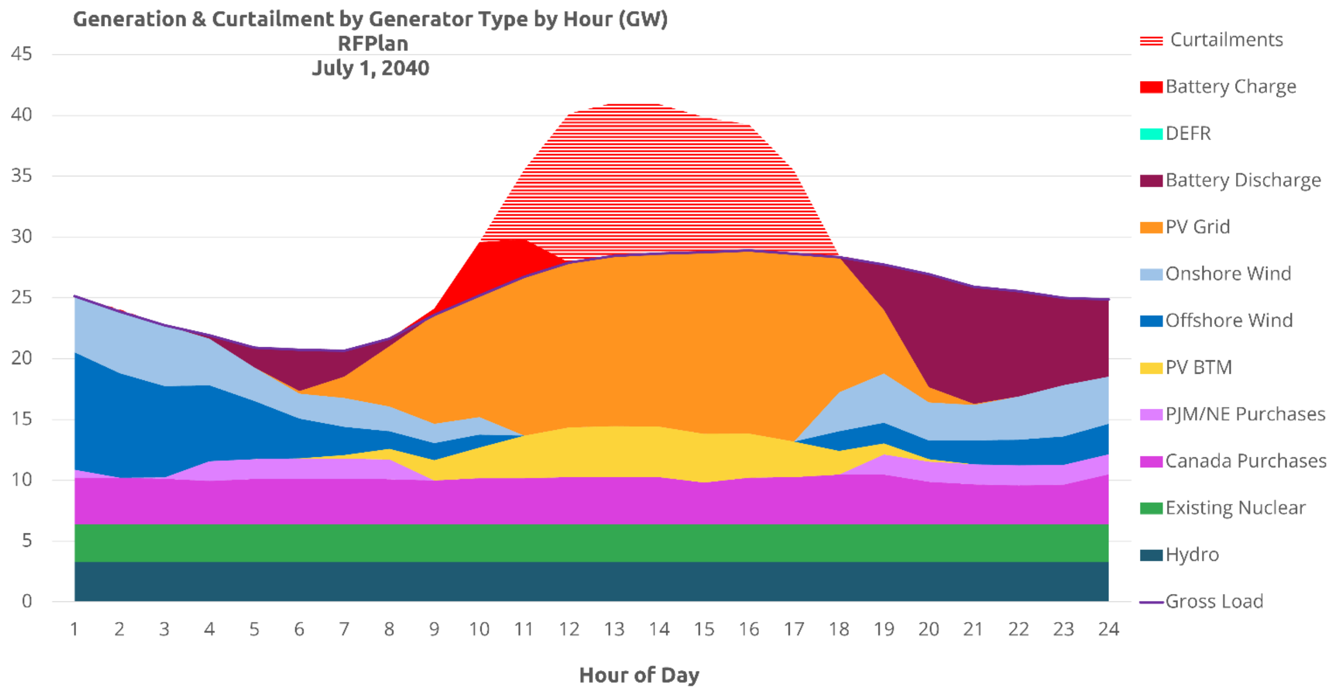
Total In-State Generation Cost: $238/MWh

[20] Modeled electric load incorporates new demand from electric vehicles (EVs) and the electrification of buildings per NYISO and NYSERDA estimates. We model zero electricity demand growth outside these two sectors, per NYISO projections.

[21] Battery charging load is part of solar and wind output.

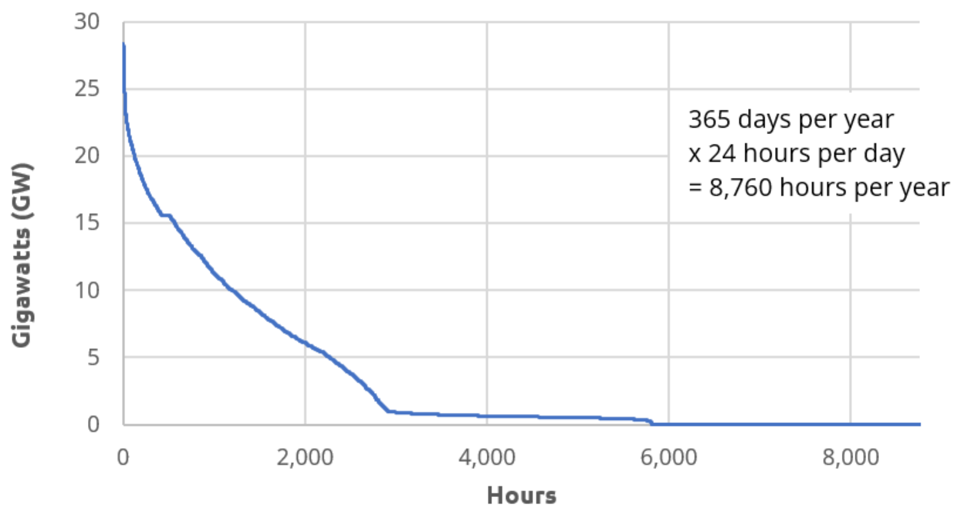
The charts below visualize how the hourly electricity load is met, midnight to midnight for a mid-winter day (January 1) and a mid-summer day (July 1). Detailed quantitative results for this scenario are given in Table B-2 in Appendix B.





These visualizations tell a striking story. The 2040 total load (245,171 GWh) has increased substantially from 2022 (159,186 GWh). The 2022 summer peak, largely reflecting air conditioning, has been replaced in 2040 by a much higher winter peak. This is largely the result of the planned electrification of building heating and transportation. The heating load is greatest in the winter, and that greater demand is met by the extended operation of the DEFR, the as-yet unspecified controllable source. The daily chart in the previous page demonstrates how the DEFR is used extensively during most days on the cooler portion of the year. Instead of using 2% of its potential annual output, as NYSERDA's modeling suggests, we find that 14.4% of the DEFR's potential annual output will be needed in our RFPlan scenario. It has to operate more than a third of the hours in the year. The load-duration curve below shows the number of hours each level of output is required from the DEFR. Most of its output is used during one-third of the year, mostly in the winter.

RFPlan DEFR Load-Duration Curve for 2040



The demand for electricity by 2040 is so great that, even with what NYISO, New York's grid operator, has described as an "unprecedented"[22] expansion of solar and wind, these renewable sources are unable to meet the demand. Solar, of course, is not available at night, so the DEFR generators have to operate for much of the year. This is shown clearly for January 1 on page 8. The batteries are charged up during many days, but charging is limited or non-existent during the winter. They discharge and are drained early in the evening, and then the DEFR has to take over to keep power on throughout the night.[23]

About 11% of the solar and wind energy generated in the RFPlan is curtailed and not sent to the grid. This is especially the case for solar power; a quarter of it is not used since, for much of the year, solar output peaks at a time of day when the demand is relatively low. In our simulation, using a nuclear-powered DEFR, this power is simply discarded. In NYSERDA's model, it would be used to produce hydrogen which will be stored for use later to generate power in a fuel cell or turbine.

[22] https://www.nyiso.com/documents/20142/2223020/2023-Power-Trends.pdf/

[23] For convenience, we arbitrarily assume the batteries start the year fully charged. That is unlikely to happen normally, since there will be little excess capacity to charge them on a mid-winter day.

The cost of electric generation under RFPlan would be more than double what it is today. We found the system costs of electricity in 2022 to be $88 per MWh. By 2040, it rises in RFPlan to $238 per MWh in constant dollars (i.e., excluding the effect of general inflation).[24] Table B-2 in Appendix B shows a detailed breakdown of these costs.

A less costly plan is possible using nuclear power for baseload generation

NYSERDA did not initially consider nuclear energy to be a "candidate resource", and it remains absent from its four modeled scenarios. However, it acknowledged, in its November 2022 presentation to the Climate Action Council, that adding 4 GW of nuclear would save money, material resources, and land.[25] In fact, NYSERDA estimated that 4 GW of nuclear could avoid the need for 12 GW of intermittent generation and 5 GW of storage and DEFR capacity. When producing heat or electric power, nuclear reactors emit no greenhouse gases. They are reliable, capable of producing power round the clock regardless of the weather. Nuclear supplied 27% of the State's electric power, on average since 1993, and was responsible for 57% of carbon-free generation during this period.[26]

Energy + Environmental Economics, Inc. (E3), the San Francisco-based consulting firm which assisted NYSERDA in performing the analysis, is familiar with the role that nuclear can play in meeting a large and varying load. In an earlier study of decarbonization in the Pacific Northwest, E3 found an important role for small modular nuclear reactors (SMRs), observing that "…achieving 100% GHG reductions using only wind, solar, hydro, and energy storage is both impractical and prohibitively expensive."[27]

Once we recognize the potential role that nuclear power can play and incorporate it into the state's future grid, we can create a plan that will reliably and affordably keep the lights on while conserving land and material resources. We present here two alternative scenarios for a future energy system having these characteristics while successfully achieving New York's climate goals.

The following scenarios, which we term "Brighter Future," build upon a 2022 policy proposal prepared by Nuclear New York, Clean Energy Jobs Coalition NY, and A Campaign for a Green Nuclear Deal.[28] Recognizing that much of New York's electricity demand is constant throughout the year, Brighter

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[24] This estimate does not include the cost of expanding the transmission network to connect the thousands of solar and wind facilities that would need to be built. The model uses 2020 costs and does not include recent substantial cost increases in solar and wind installations. (Cost assumptions are shown in Appendix C.)

[25] https://climate.ny.gov/-/media/project/climate/files/2022-11-07-CAC-Meeting-Presentation.pdf

[26] https://data.ny.gov/Energy-Environment/Electric-Generation-By-Fuel-Type-GWh-Beginning-196/h4gs-8qnu

[27] https://www.ethree.com/wp-content/uploads/2019/03/E3_Resource_Adequacy_in_the_Pacific-Northwest_March_2019.pdf

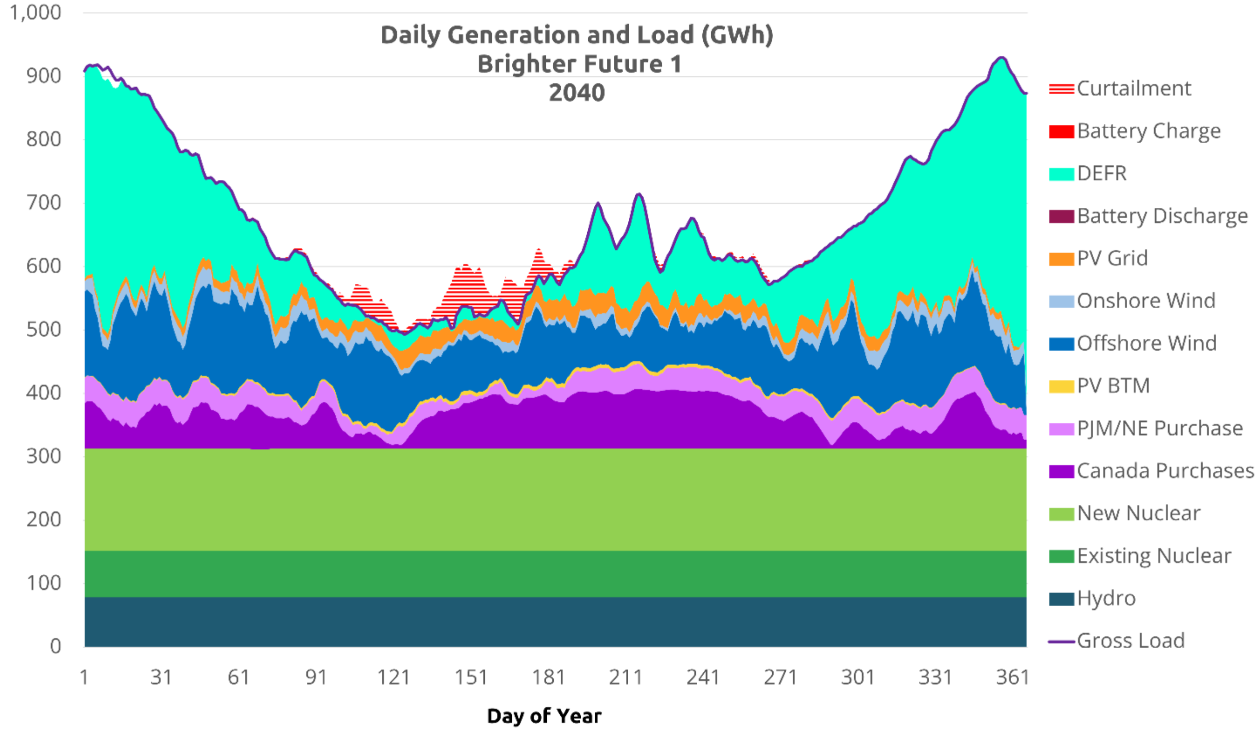
[28] https://www.nuclearny.org/bright-future/

Future utilizes nuclear power as a principal source of clean power throughout the year, not simply as a DEFR when solar and wind are incapable of meeting the load. Nuclear becomes the *backbone* of the system, not simply a *backup* to intermittent, weather-dependent renewables.

These scenarios include 7 GW of new baseload nuclear power – adding more than twice what is already operating in upstate New York – along with 26 to 30 GW of DEFR. Far fewer solar and wind installations are needed; we assume 80% fewer installations than in RFPlan. Our grid model presently does not allow for the DEFR to charge batteries. Since adding batteries that are seldom charged adds unnecessary costs, we exclude them from the Brighter Future scenarios. We will evaluate their inclusion in future research.

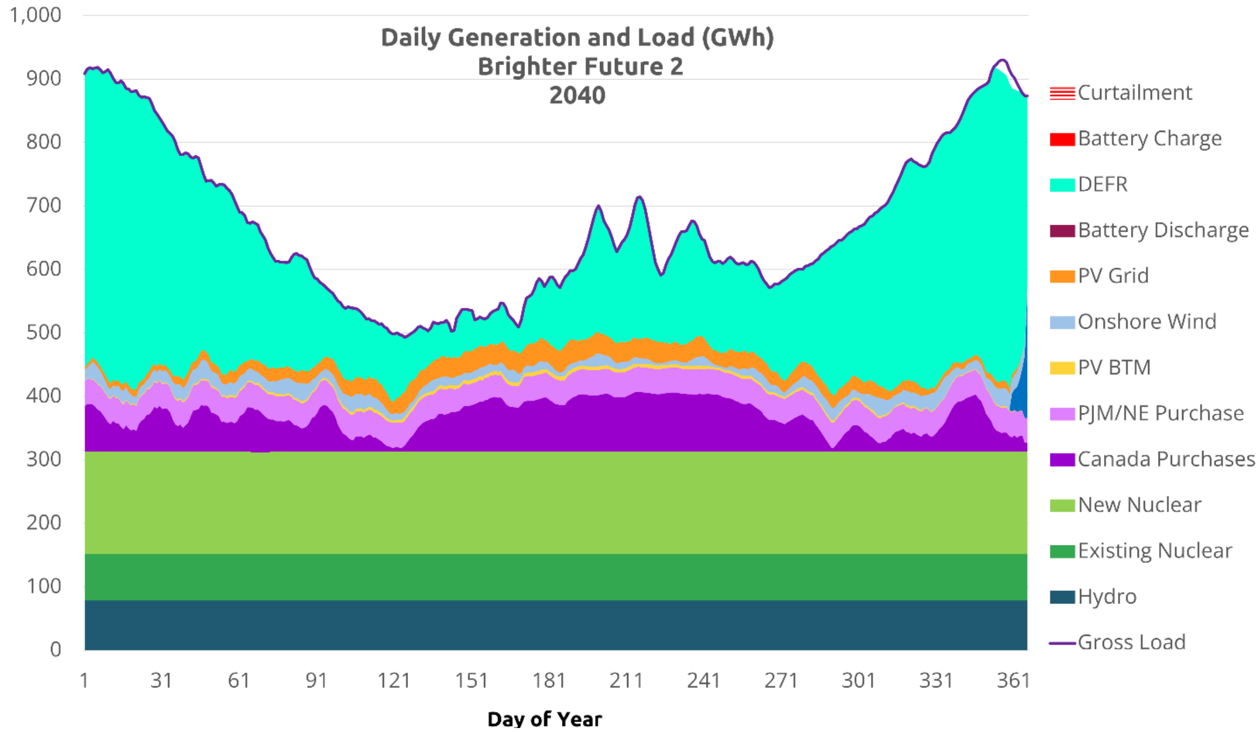
The first, Brighter Future 1, has 9 GW of offshore wind, the minimum called for in the CLCPA. Brighter Future 2 has no offshore wind and costs significantly less. Not only does offshore wind add to the system cost, but it will be shut down, and possibly seriously damaged whenever frequent and increasingly intense storms arrive from the Caribbean and South Atlantic.[29]

[29] Will New York City Survive the State's Energy Plan? Dr. Rodberg's testimony before the NYC City Council Committee on Environmental Protection, 2020. https://www.dropbox.com/s/e2g9af0pefiulm2/Will%20NYC%20Survive%20the%20State%27s%20Energy%20Plan%20-%20Testimony%20of%20Leonard%20Rodberg.pdf?dl=0



2040 Electricity Generation Brighter Future 1				
Source	**Capacity MW**	**Output GWh/yr**	**Capacity Factor %**	**% Load**
Existing Nuclear	3,305	26,700	92.2%	10.9%
New Nuclear	7,000	58,901	96.1%	24.0%
Hydro	4,612	28,619	70.8%	11.7%
PV BTM	1,202	1,394	13.2%	0.6%
PV Grid	6,831	7,308	12.1%	3.0%
Onshore Wind	2,603	5,423	23.8%	2.2%
Offshore Wind	9,000	35,814	45.4%	14.6%
DEFR	26,000	47,735	21.0%	19.4%
NE and PJM Purchases		11,542		4.7%
Canada Purchases		21,080		8.6%
Load		245,171		100.0%
Total In-State Generation Cost $176/MWh				

See Table B-3-1 in Appendix B for detailed quantitative results for this scenario.



2040 Electricity Generation Brighter Future 2				
Source	**Capacity MW**	**Output GWh/yr**	**Capacity Factor %**	**% Load**
Existing Nuclear	3,305	26,700	92.2%	10.9%
New Nuclear	7,000	58,901	96.1%	24.0%
Hydro	4,612	28,619	70.8%	11.7%
PV BTM	1,202	1,394	13.2%	0.6%
PV Grid	6,831	7,918	13.2%	3.2%
Onshore Wind	2,603	5,764	25.3%	2.4%
DEFR	30,000	79,889	30.4%	32.6%
NE and PJM Purchases		14,253		5.8%
Canada Purchases		21,080		8.6%
Load		245,171		100.0%
Total In-State Generation Cost $150/MWh				

Table B-3-2 in Appendix B provides detailed quantitative results for this scenario.

Nuclear plants require just a few acres of land and have negligible impact on the surrounding physical environment.[30] Comprehensive lifecycle analysis by the United Nations Economic Commission for Europe shows that, compared with other energy technologies, nuclear power has substantially lower ecosystem impacts when considering climate change, land use, and human health.[31] Most importantly,

[30] https://ourworldindata.org/land-use-per-energy-source

[31] https://unece.org/sed/documents/2021/10/reports/life-cycle-assessment-electricity-generation-options

even before accounting for transmission expansion costs, or the nuclear capital cost reductions likely to occur as plants are deployed across the U.S., the Brighter Future scenarios cost substantially less than the RFPlan.

The below table summarizes our findings and provides total per-unit generation costs for in-state resources under two DEFR capital cost scenarios: current-cost at ~$6,000/kW and low-cost at ~$3,000/kW.[32]

2040 Scenarios	DEFR Requirement (GW)	DEFR Capacity Utilization	Total In-State Generation Cost ($/MWh)	
			Current Cost DEFR (~$6,000/kW)	Low-Cost DEFR (~$3,000kW)
RFPlan	29	14.4%	$238	$211
Brighter Future 1	26	20.3%	$176	$143
Brighter Future 2	30	29.6%	$150	$111

It should be noted that the data in our model use current estimated capital costs for new nuclear facilities, $10,000/kW for new gigawatt-scale plants. The electricity costs in the Brighter Future scenarios could be substantially lower as multiple successive installations bring nuclear plant costs down, as South Korea, France, Japan, and others have demonstrated (e.g., South Korea has installed large plants for $2,500/kW). An independent assessment by the Massachusetts Institute of Technology's Center for Advanced Nuclear Energy Systems in March 2022 expected overnight capital cost of the next gigawatt-scale plant in the U.S. to be $4,300/kW.[33]

A large dispatchable emission-free resource is essential. What should it be?

Our results suggest that decarbonization of the grid requires a large-capacity dispatchable emission-free resource running a significant part of the year. What can it be? What can power it?

A number of suggestions have been offered:

- Fuel cells or gas turbines powered by “green hydrogen”: Hydrogen fuel cells or combustion power plants similar to those now burning fossil fuels could run on “green hydrogen” produced in electrolyzers powered by renewable energy, as NYSERDA has suggested. However, such a plan requires the creation of an expensive infrastructure to transport and store the hydrogen, as well as a buildout of additional costly, land-hungry solar and wind facilities to power the hydrolysis plants

[32] Note that the DEFR cost per kW is calculated on the peak system output of 500 MW. Adjusting for the Natrium reactor’s steady output of 345 MW of power, the costs are $9,000 per reactor kW.

[33] The analysis was specific to Westinghouse’s AP1000, a design with fully completed detailed specifications, real-world in-country operating experience, a ready construction workforce, and regulatory familiarity. https://web.mit.edu/kshirvan/www/research/ANP193%20TR%20CANES.pdf

that produce the hydrogen. Using hydrogen for energy storage is challenged, also, by the fact that the round-trip power-to-gas-to-power (P2G2P) efficiency is just 40%.[34] This means more than twice as much additional energy is needed as will be generated by the DEFR, with a commensurate drain on material resources, land, and societal wealth.

- Long-duration storage: This might help, but currently no realistic scalable form of such storage exists. If it did, it, too, would require a vast expansion of generating capacity if solar and wind power charges whatever storage medium is used.
- Carbon capture and storage (CCS) attached to gas-fired power plants: This only exists on an experimental basis. It would add substantial cost to the power it was attached to, and there would be upstream leakage of greenhouse gases and other pollutants to the environment. The captured CO_2 would have to be disposed of, presumably underground, adding additional cost as well as potential environmental damage.
- Nuclear power: This is the DEFR energy source used in each of our scenarios, as well as for additional baseload generation in the Brighter Future scenarios. Only nuclear power has been demonstrated to have the necessary capabilities, not only in the gigawatt-scale reactors now operating in New York State and elsewhere, but in the smaller reactors now under commercial development and operating on submarines and ships for over fifty years (many designed in New York State at the Knolls Atomic Power Laboratory).
- Alternate nuclear options: Alternate ways of using nuclear energy will deserve consideration. Nuclear reactors, like most energy sources, are most cost-efficient when they run more of the time to meet demand. We found that the DEFR would be operating at partial capacity for most of the year. A more cost-effective plan might use a smaller number of reactors running continuously to produce hydrogen which could be used in fuel cells. Another option would be to use nuclear facilities to produce carbon-neutral synthetic fuels.[35,36] Full analysis of the cost and suitability of these options is beyond the scope of this paper, but they deserve serious study.

[34] https://www.sciencedirect.com/science/article/pii/S1040619021001330

[35] Operational Energy from Seawater, US Naval Research Laboratory. https://www.hydrogen.energy.gov/pdfs/review18/ia018_willauer_2018_p.pdf

[36] https://www.thechemicalengineer.com/features/fuelling-the-world-with-biomass/

Limitations of the model/future research

The model we are using, while it shows the principal properties and requirements for the future grid, has significant limitations as well. Among these are:

1. Simplified view of in-state transmission: This model treats the state's grid as a single unit without transmission constraints, whereas we know that there are significant barriers to the flow of power between areas of the state. The model also does not reflect transmission upgrade costs that will occur with economy-wide electrification irrespective of the chosen technologies. However, we expect transmission upgrade challenges to be larger, both politically and financially, if large capacities of intermittent generation sources need to be integrated. Both NYISO and the group at Cornell working with Prof. C. Lindsay Anderson have explored the difficulties to be encountered when large amounts of distributed sources are introduced.[37,38]
2. Absence of reserves: Our model does not reflect the reserve requirements imposed by state and federal law. NYSERDA's Integration Analysis does not incorporate these, either.
3. Fixed cost assumptions: We have not explored the wide range of future costs that seem likely for both renewable and nuclear resources, as well as for possible hydrogen and synthetic fuel options.
4. Smart nuclear downtime scheduling: The vast majority of nuclear reactor downtime is for scheduled maintenance and refueling. Routinely, such downtime is placed during periods of predicted low demand, currently in the spring and fall. While our model currently represents nuclear generation as flat throughout the year at a reduced capacity factor, full nuclear capacity should be available through the entire winter, the season of peak future demand. Incorporating this into the model would reduce the needed DEFR capacity.
5. Limited use of battery-nuclear combination: Our model dispatches batteries before the DEFR and never uses the DEFR to charge batteries, and our BF scenarios do not use batteries at all. We will explore in future work how strategic delay of battery discharging and charging of batteries by DEFRs can reduce needed DEFR capacity in both RFPlan and BF scenarios.
6. Improved DEFR design: The chosen DEFR in our model drops from 500 MW to 345 MW capacity when its thermal storage is depleted. Having a DEFR with maximum capacity always available,

[37] https://www.nyiso.com/documents/20142/32976598/2021-2040_System_Resource_Outlook_Report_v19_MC.pdf/c638407b-65f9-fe53-4314-9ddce613378f
[38] https://arxiv.org/abs/2307.15079

perhaps accompanied by batteries, might be more cost-effective than the example we have used. This will be explored in future work.

Conclusion

We have shown, with a modeling tool capable of performing an hour-by-hour analysis, that dispatchable emission-free resources are essential to meeting the goal of a reliable, zero-emission grid. Further, this clean dispatchable source must be able to run a large portion of the year. The only such source likely to be available within the next several decades is nuclear power. The state will further benefit from the deployment of additional baseload nuclear power. This combination of nuclear resources will be more cost-efficient and environmentally-protective than an alternative focused on intermittent weather-dependent sources.

Appendix A: CACI Grid Model Methodology

The New York adaptation of the CACI Grid Model works as follows:

In this model, each type of energy source is dispatched hourly to address electric loads, taking account of inter-regional power purchases and sales. CO_2 emissions (if any), energy pricing, and the occurrence of surplus energy each hour from excessive non-dispatchable generation is also calculated.

Model inputs include hourly data for loads, solar generation, wind generation, hydro generation, and power exchange with other regions. The assumptions and methods used in the model are as follows:

Power generation is represented in these simplified categories: behind the meter (BTM) and grid-connected solar, onshore and offshore wind, hydroelectric, nuclear, battery storage, and a series of possible dispatchable sources. For earlier years, when the burning of fossil fuels is permitted, gas-fired combined-cycle and simple-cycle plants are included. Existing nameplate capacities are taken from NYISO publications, while actual output is based on 2022 NYISO data.

Total system loads are estimated using 2022 data from New York Independent System Operator (NYISO), which operates the State's electric grid.[39] Projections of current demand, as well as the new demand from electric vehicles (EVs) and the electrification of buildings, are drawn from those developed by NYISO and the New York State Energy Research and Development Authority (NYSERDA).[40]

Hourly generation from solar and onshore and offshore wind is scaled up based on the distribution of 2022 hourly output data for these sources, and offshore wind uses 2021 hourly net capacity factors provided by NYISO.[41,42] Hourly load shapes are estimated by reviewing hourly data for weekend/holidays and weekdays. Maximum and minimum daily loads are adjusted weekly based on historic data to account for seasonal variation and adjusted annually based on load growth projected by NYISO. Purchases from Canada and PJM-NE are modeled based on 2022 actual hourly data.

The maximum capacity of solar and wind facilities reflects the regional distribution of generators and the likelihood that they can operate at the same time. These values are different from nameplate

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[39] NYISO Open Access Same-Time Information System http://mis.nyiso.com/public/

[40] EV and Building Electricity Table I-1d, 2022 NYISO Gold Book https://www.nyiso.com/gold-book-resources

[41] NYISO Offshore Wind Profile Development – Summary. February 07, 2023. https://www.nyiso.com/documents/20142/36079056/4%2023_02_07_ICAPWG_OffshoreWindProfileDevelopment.pdf/a982dbb7-b1f3-cee0-ed21-b1f5e3d54539

[42] https://www.nyiso.com/documents/20142/36079056/4%20NYISO_OffshoreWind_Hourly_NetCapacityFactor.xlsx/dc15cb6a-b6fc-6a6a-e1d0-467d5c964079

capacity which represents the output of a single unit at a specified point, used to calculate installation cost. Maximum capacity is derived from evaluating actual generating data in 2022 from NYISO. Until actual data is available for offshore wind installations, offshore wind is assumed to have the same relationship of maximum regional output to nameplate capacity as onshore wind,

Capacity factors – the fraction of the potential output of a source that is actually produced during the year – are not assumed but are calculated by the model, based upon the weather and the behavior of the grid.

The Zero-emission Firm Resource utilized in the NYSERDA's scenarios – referred to in this paper by the acronym DEFR (Dispatchable Emission-Free Resource) – is modeled using the characteristics of the TerraPower Natrium small modular reactor.[43]

Battery storage is modeled by assuming the batteries are charged when there is more inflexible power from hydropower, nuclear, grid-connected solar, and wind than is needed to meet demand. The DEFR is not used to charge batteries. The batteries are discharged when the load on the grid is greater than can be provided by those ongoing inflexible sources.

Hourly loads and source dispatch are determined for each day of the year. Hourly load patterns are modeled based on 2022 data available from NYISO. Hourly load shapes are selected for workdays and for non-work holiday/weekend days and adjusted weekly for seasonal changes. NYISO reports estimated generation from behind-the-meter solar, even though it occurs on the customer side of the grid. Behind-the-meter solar currently represents the majority of solar electric generation capacity, but that will change as State plans proceed.

Each source is dispatched in turn to meet the load, as follows: behind-the-meter solar is introduced first, leaving the remaining load to be served by the various sources connected to the grid. Purchases from the neighboring states and Canada are added. Existing nuclear plant output is added as "must-run" capacity. Hydroelectric generation is added. Output from grid- connected solar plus onshore and offshore wind generation are then added, taking into account their hourly variations as described above.

Three percent of the maximum annual load is set aside for system control by gas combined-cycle plants or battery discharge, representing spinning reserve and other ancillary grid services. This is required even when there are curtailments of solar and wind generation.

[43] https://www.terrapower.com/our-work/natriumpower/

When there is unmet load remaining after these non-dispatchable sources have been included, the batteries are called on to discharge up to their ability. If unmet load still remains, then the DEFR is used to supply the remaining load.

Curtailments occur when total non-dispatchable generation exceeds the load requirements. When there is insufficient load to use all possible solar and wind generation, purchases from Canada and PJM/NE are reduced or eliminated. Then curtailments are assigned in random order to offshore wind, onshore wind, and grid-connected solar, but not to BTM solar, which is not controlled by the grid operator.

The model uses current dollars so that the effects of future inflation do not confuse the analysis. Costs of energy sources are estimated from a variety of data sources. The prices used in the scenarios reported here are shown in Appendix C. The total native generation cost of electricity is the weighted average of annual generation sources. The cost for each generation source includes fixed and variable operation and maintenance (O&M) cost, fuel cost, and capital recovery.

We are not reporting energy generator revenues as we have not analyzed the breakdown between energy market income vs. revenue from capacity and ancillary service auctions operated by NYISO. The actual revenue sources depend upon varying arrangements for tax subsidies and other mechanisms for shifting costs from, and among, ratepayers, so this data would be too uncertain to be meaningful.

Appendix B: Data Sheets

Table B-1: 2022 Electricity Generation and Costs

Generation Summary						2022				
Non-dispatchable	**Capacity** MW	**Generation** GWh/yr	**Capacity Factor** %	**% Total Load**	**Capital Cost** $/kW	**Fixed O&M** $/MWh	**Variable O&M** $/MWh	**Fuel Cost** $/MWh	**Capital Recovery** $/MWh	**In-State Generation Cost** $/MWh
Existing Nuclear	3,305	26,700	92.2%	16.8%	$141	$28.61	$1.22	$4.09	$2.84	$36.75
Hydro	4,265	26,466	70.8%	16.7%		$7.06	$1.48	-	-	$8.54
PV BTM	3,760	4,360	13.2%	2.7%	$4,647	$17.25	-	-	$720.81	$738.06
PV Grid	154	179	13.2%	0.1%	$1,281	$13.75	-	-	$198.64	$212.39
Onshore Wind	2,191	4,861	25.3%	3.1%	$2,701	$12.43	-	-	$218.97	$231.40
Biomass	258	2,261	100.1%	1.4%		$15.02	$5.06	-	-	$20.08
Sub Total	13,933	64,828	53.1%	40.8%		$17.32	$1.28	$1.68	$66.61	$86.90
Dispatchable	**Capacity** MW	**Generation** GWh/yr	**Capacity Factor** %	**% Total Load**	**Capital Cost** $/kW	**Fixed O&M** $/MWh	**Variable O&M** $/MWh	**Fuel Cost** $/MWh	**Capital Recovery** $/MWh	**In-State Generation Cost** $/MWh
Gas CC	10,843	60,293	63.5%	38.0%	$1,485	$2.30	$1.96	$31.53	$44.35	$80.14
Gas CT	4,186	2,577	7.0%	1.6%	$979	$11.91	$4.71	$49.03	$228.82	$294.47
Steam Plants	10,637	539	0.6%	0.3%		$2.30	$1.96	$31.53	$44.35	$80.14
Sub Total	25,666	63,409	28.2%	39.9%		$92.66	$2.07	$32.24	$51.85	$88.85
In-State Generation		128,237		80.8%						$87.86

Regional purchases	Purchased GWh/yr	% Total Load		Total GWh	% Total Load
NE and PJM Purchases	14,401	9.1%	Curtailments	0	0.0%
Canada Purchases	16,086	10.1%	Unmet Load	0	0.0%
Sub Total	30,487	19.2%			
Total	158,724	100.0%			

Note: O&M Operation and Maintenance

Steam Plants are ascribed the same economics of Gas CC plants.

Table B-2: Renewable-Focused RFPlan Generation and Costs (2040)

Generation Summary					RFPlan (2040)					
Non-dispatchable	**Capacity** MW	**Generation** GWh/yr	**Capacity Factor** %	**% Total Load**	**Capital Cost** $/kW	**Fixed O&M** $/MWh	**Variable O&M** $/MWh	**Fuel Cost** $/MWh	**Capital Recovery** $/MWh	**In-State Generation Cost** $/MWh
Existing Nuclear	3,355	27,104	92.2%	11.3%	$141	$28.61	$1.22	$4.09	$1.58	$35.49
Hydro	4,612	28,619	70.8%	11.9%	-	$7.06	$1.48	-	-	$8.54
PV BTM	6,009	6,968	13.2%	2.8%	$4,647	$17.25	$0.00	-	$400.78	$418.03
PV Grid	34,154	32,100	10.7%	13.1%	$1,281	$16.96	$0.00	-	$136.26	$153.23
Onshore Wind	13,017	26489	23.2%	10.8%	$2,701	$13.55	$0.00	-	$132.75	$146.30
Offshore Wind	14,400	56,457	44.5%	22.9%	$8,588	$29.53	$0.01	-	$220.21	$248.74
Sub Total	75,547	177,603	26.8%	72.4%		$20.60	$0.43	$0.63	$130.02	$151.68

Dispatchable	**Capacity** MW	**Generation** GWh/yr	**Capacity Factor** %	**% Total Load**	**Capital Cost** $/kW	**Fixed O&M** $/MWh	**Variable O&M** $/MWh	**Fuel Cost** $/MWh	**Capital Recovery** $/MWh	**In-State Generation Cost** $/MWh
Battery Discharge	20,709	[8,398][44]	4.5%	[3.4%]	$1,387	$64.01	-	-	$533.01	$577.02
DEFR	29,000	36,680	14.4%	15.0%	$5,988	$90.49	$3.14	$4.61	$420.08	$524.33
Sub Total	49,709	36,680		15.0%		127.88	$2.47	$4.61	$543.54	$656.44
In-State Generation		214,283		87.4%						$238.08

Regional purchases	Purchased GWh/yr	% Total Load		Total GWh	% Total Load
NE and PJM Purchases	8,082	3.7%	Curtailments	14,703	6.0%
Canada Purchases	21,080	8.6%	Unmet Load	141	0.1%
Sub Total	30,162	12.3%			

Total	245,171	100.0%

[44] Battery charging load is part of solar and wind output.

Table B-3-1: Brighter Future 1 Generation and Costs (2040)

Generation Summary					Brighter Future 1 (2040)					
Non-dispatchable	**Capacity** MW	**Generation** GWh/yr	**Capacity Factor** %	**% Total Load**	**Capital Cost** $/kW	**Fixed O&M** $/MWh	**Variable O&M** $/MWh	**Fuel Cost** $/MWh	**Capital Recovery** $/MWh	**In-State Generation Cost** $/MWh
Existing Nuclear	3,305	26,700	92.2%	10.9%	$141	$28.61	$1.22	$4.09	$1.58	$35.49
New Nuclear	7,000	58,901	96.1%	24.0%	$9,992	$15.14	$2.48	$4.10	$105.88	$128.59
Hydro	4,612	28,619	70.8%	11.7%	-	$7.06	$1.48	-	-	$8.54
PV BTM	1,202	1,394	13.2%	0.6%	$4,647	$17.25	$0.00	-	$400.78	$418.03
PV Grid	6,831	7,308	12.2%	3.0%	$1,281	$14.90	$0.00	-	$119.71	$134.61
Onshore Wind	2,603	5,423	23.8%	2.2%	$2,701	$13.23	$0.00	-	$129.67	$142.90
Offshore Wind	9,000	35,814	45.4%	14.6%	$8,588	$28.94	$0.01	-	$215.81	$244.5
Total	34,553	164,165	54.2%	67.0%		$18.87	$1.36	$2.16	$98.70	$121.05

Dispatchable	**Capacity** MW	**Generation** GWh/yr	**Capacity Factor** %	**% Total Load**	**Capital Cost** $/kW	**Fixed O&M** $/MWh	**Variable O&M** $/MWh	**Fuel Cost** $/MWh	**Capital Recovery** $/MWh	**In-State Generation Cost** $/MWh
DEFR	26,000	47,735	21.0%	19.5%	$5,988	$62.34	$3.14	$4.61	$293.54	$363.63
Sub Total	26,000	47,735	21.0%	19.5%	$5,988	$62.34	$3.14	$4.61	$293.54	$363.63
In-State Generation		211,899		86.4%						$175.70

Regional purchases	Purchased GWh/yr	% Total Load		Total GWh	% Total Load
NE and PJM Purchases	11,542	4.7%	Curtailments	3,379	1.4%
Canada Purchases	21,080	8.6%	Unmet Load	148	0.1%
Sub Total	32,622	13.3%			
Total	245,171	100.0%			

Table B-3-2: Brighter Future 2 Generation and Costs (2040)

Generation Summary				Brighter Future 2 (2040)						
Non-dispatchable	**Capacity** MW	**Generation** GWh/yr	**Capacity Factor** %	**% Total Load**	**Capital Cost** $/kW	**Fixed O&M** $/MWh	**Variable O&M** $/MWh	**Fuel Cost** $/MWh	**Capital Recovery** $/MWh	**In-State Generation Cost** $/MWh
Existing Nuclear	3,305	26,700	92.2%	10.9%	$141	$28.61	$1.22	$4.09	$1.58	$35.79
New Nuclear	7,000	58,901	96.1%	24.0%	$9,992	$15.33	$2.48	$4.10	$106.88	$128.59
Hydro	4,612	28,619	70.8%	11.7%	-	$7.06	$1.48	-	-	$8.54
PV BTM	1,202	1,394	13.2%	0.6%	$4,647	$17.25	$0.00	-	$400.78	$418.03
PV Grid	6,831	7,818	13.2%	3.2%	$1,281	$13.76	$0.00	-	$110.49	$124.25
Onshore Wind	2,603	5,764	25.3%	2.4%	$2,701	$12.45	$0.00	-	$122.00	$134.45
Sub Total	25,553	129,302	57.8%	52.7%		$15.95	$1.71	$2.71	$65.54	$85.90

Dispatchable	**Capacity** MW	**Generation** GWh/yr	**Capacity Factor** %	**% Total Load**	**Capital Cost** $/kW	**Fixed O&M** $/MWh	**Variable O&M** $/MWh	**Fuel Cost** $/MWh	**Capital Recovery** $/MWh	**In-State Generation Cost** $/MWh
DEFR	30,000	79,889	30.4%	32.6%	$5,988	$42.98	$3.14	$4.61	$202.38	$253.11
Sub Total	30,000	79,889	30.4%	32.6%	$5,988	$42.98	$3.14	$4.61	$202.38	$253.11

In-State Generation	209,191	85.3%	$149.76

Regional purchases	**Purchased** GWh/yr	**% Total Load**		**Total** GWh	**% Total Load**
NE and PJM Purchases	14,253	5.8%	Curtailments	22	0.0%
Canada Purchases	21,080	8.6%	Unmet Load	145	0.01
Sub Total	35,333	14.0%			

Total	245,171	100.0%

Appendix C: Energy Source Assumptions

	New Nuclear	DEFR (Flex Nuclear)	Battery Storage	PV BTM	PV Grid	Onshore Wind	Offshore Wind
Overnight Capital Cost ($/kW)	8,632	5,173	1,387	4,600	1,205	2,491	8,386
Interest During Construction ($/kW)	1,361	815	0	47	76	211	202
Total Capital Cost ($/kW)	9,992	5,998*	1,387	4,647	1,281	2,701	8,588
Economic Life (years)	30	30	10	20	20	20	20
Capital Recovery Rate (%/year)	9	9	15	10	10	10	10
Fixed O&M ($/kW-year)	127	114	26	20	16	28	115
Variable O&M ($/MWh)	2.48	3.14	0.00	0.00	0.00	0.00	0.01
Fuel Cost ($/MWh)	4.10	4.61	-	-	-	-	-
Nameplate Electric Capacity (MW)	2,156	500	50	0.01	150	200	400
Charging Rate (% of Max Output MW)	0	0.69	1.00	0	0	0	0
Storage Capacity (hours)	0	5.5	4.0	0	0	0	0

* Capital cost based on 500 MW, equivalent to $8,678/kW for 345 MW reactor.