The Road to 100% Renewable Electricity by 2030 in Rhode Island

TECHNICAL SUPPORT DOCUMENT

PREPARED BY

The Brattle Group

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Brattle

STATE OF RHODE ISLAND
OFFICE OF ENERGY RESOURCES

CONTENTS

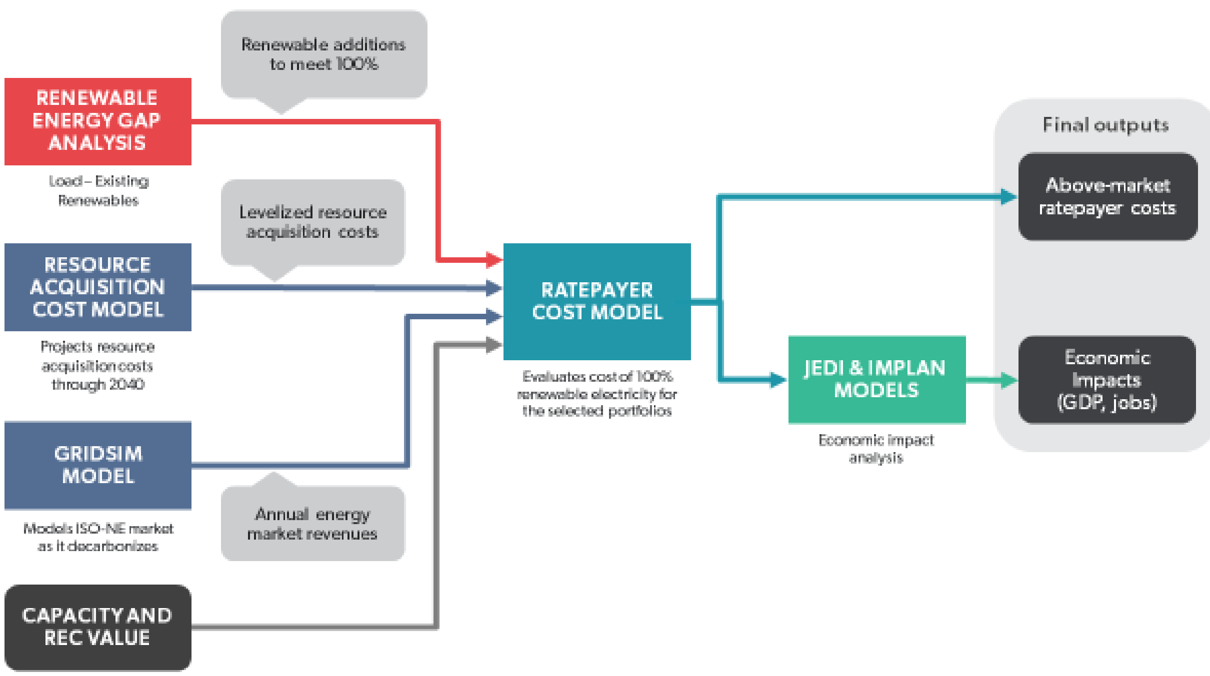
I. Introduction

This Technical Support Document accompanies the report titled "The Road to 100% Renewable Electricity by 2030 in Rhode Island" (the "Report"). The goal of this document is to provide additional detail on the analyses supporting the Report, including an overview of the analytic methodology and assumptions used.

A. Analytical Methodology

The analyses are based on four separate models, illustrated schematically in **FIGURE 1**. Except for the IMPLAN and JEDI models for analyzing economic impacts, these are proprietary models of The Brattle Group.

FIGURE 1: ANALYTICAL MODEL OVERVIEW



The analytic portion of this study consisted primarily of three analyses:

1. the renewable supply gap analysis,
2. the ratepayer above-market cost impact analysis (includes several subcomponents), and
3. the economic impact analysis.

All costs are evaluated in real dollar terms and expressed in 2020 dollars. We assume an inflation rate of 2% to convert costs into 2020 dollars.

The *renewable supply gap analysis* establishes the amount of additional renewable energy resources that Rhode Island must procure through 2030 to achieve 100% renewable electricity (the "gap"). To establish the gap in 2030, we developed a Rhode Island electricity demand forecast through 2030 and compared it to Rhode Island's renewable generation. The latter accounts for existing and committed resources – existing resources, plus resources already committed but not yet online, reduced for resources that will retire or contracts that will expire by 2030.

We developed a set of resource portfolios consisting of alternative resource types and combinations of these types that would fill the gap with renewable electricity to meet the 2030 goal. For each of these portfolios, we estimated the *ratepayer above-market costs* to reach 100% renewable electricity, including the uncertainty in costs. The above-market costs account for the both the acquisition cost of the additional renewable resources (including their interconnection costs) and the offsetting market revenues they would earn for selling their energy, capacity and renewable energy credits (RECs) to the regional market. We developed long-term projections of how market prices may change in the future as the New England electricity system evolves toward more renewable generation and less fossil.

The *economic impact analysis* measures how the addition of these alternative renewable energy resources would affect Rhode Island's Gross Domestic Product (GDP) and in-state employment. These impacts occur through the effects on ratepayer costs as well as through in-state construction and operating expenditures (for in-state resources). This analysis utilizes NREL's JEDI model and the IMPLAN model.

II. Renewable Supply Gap Analysis

The gap to 100% renewable energy in 2030 is the difference between the state's projected total electricity demand in 2030 and the renewable generation that Rhode Island has already procured and that will be online in 2030.

A. Electricity Demand Forecast

We developed Rhode Island electricity demand forecasts from 2020 to 2030, and also project demand growth out to 2050, based on assumptions about the pace and extent of electrification of the heating and transportation sectors. While 2050 is beyond the horizon of this analysis, it is helpful for illustrating that achieving 100% renewables by 2030 is only a milestone on the way to full decarbonization of the economy, since electrification of other sectors is likely to increase electricity demand significantly in the long term. In addition to forecasting Rhode Island demand, we develop corresponding projections of New England electricity demand to 2030 and beyond, to support modeling of the New England electricity system (see Section VI), which provides price projections that support the economic analyses. Beyond 2030, the primary driver of load is new electrification loads in the region.

We consider three cases for Rhode Island demand from 2020 to 2030: Base Load Case, High Load Case, and Low Load Case. These forecasts are based primarily on the 2019 Rhode Island electric demand forecast provided by National Grid to 2030. National Grid's forecast assumes a light-duty electric vehicle market share of approximately 2.5% and does not include any electrification of medium or heavy-duty vehicles, or any additional heating electrification. It also assumes 150 GWh/year of energy efficiency and 130 GWh per year of behind-the-meter solar PV from 2020 to 2030. Our Base Load Case adjusts the National Grid forecast to account for transmission losses (2%) in addition to the distribution losses (6%) already considered, and also assumes somewhat more electrification-related demand by 2030, with the same level of energy efficiency. This projection was adjusted for the High and Low Cases to account for different assumptions about the amount of additional electrification load from transportation and heating, and about continued implementation of energy efficiency. To account for uncertainty in load projections, the High Load Case accounts for potentially higher electrification levels, and the Low Load Case accounts for higher levels of energy efficiency and lower electrification levels. The underlying assumptions for these load scenarios are summarized in **TABLE 1**; Figure 2 of the Report illustrates the Base, High and Low Load Cases.

Based on data provided by the Rhode Island Office of Energy Resources (OER), approximately 10% of the behind-the-meter (BTM) net metering facilities are qualified to produce RECs. To account for the load served by this BTM generation (which is not included in the load forecast) and avoid underestimating the state's REC requirement, we adjusted the net electricity demand upward by the generation from net metering facilities qualified to produce RECs. We used the net load with this BTM adjustment to establish the magnitude of the gap and ensure the proper accounting of RECs.[1] **TABLE 1** displays net electricity demand both with and without this BTM adjustment.

TABLE 1: 2030 DEMAND FORECAST ASSUMPTIONS

	NGrid	Brattle		
	Base	Base Load Case	High Load Case	Low Load Case
Light-duty vehicle (LDV) market share	~2.5%	5%	15%	2.5%
Medium- and heavy-duty vehicle load	Not included	Roughly same energy share as LDVs	Roughly same energy share as LDVs	None
Heating (% of additional RI households that fully electrify)	Not included	5%	10%	None
EE cumulative savings	4,020 GWh by 2030	Same as NGrid	Same as NGrid	4,390 GWh by 2030
Net load in 2030 (GWh)	**7,190**	**7,500**	**8,130**	**6,830**
Net load in 2030 w/ BTM adjustment (GWh)	**7,360**	**7,670**	**8,300**	**7,000**

[1] When estimating the levelized ratepayer costs, we used the net electricity demand without the BTM generation adjustment.

B. Existing and Committed Renewable Electricity Resources

The renewable generation that Rhode Island has already procured and that will be online in 2030 include renewables procured through the Renewable Energy Growth (REG) program, virtual and direct net metering, and long-term contracts.[2] The long-term contracts include Rhode Island's 400 MW share of the Revolution Wind project, expected online by 2024. These renewable supply resources are summarized in **TABLE 2** below, and are reflected in Figure 3 of the Report.

TABLE 2: EXISTING AND PROCURED RENEWABLE GENERATION ONLINE IN 2030

	Capacity (MW)	Generation (GWh/yr)	Online Year	Contract Expiration
REG				
Solar	215	255	n/a	n/a
Wind	28	73	n/a	n/a
Virtual and Direct Net Metering	583	689	n/a	n/a
Long-term Contracts				
Pre-2019 Resources	38	162	Pre-2019	Various
Woods Hill Solar	2	2	2019	2039
Hope Farm Solar	5	7	2020	2040
Cassadaga Wind	19	58	2021	2034
Sanford Airport Solar	4	5	2021	2041
Chinook Solar	2	7	2022	2042
Farmington Solar	4	5	2022	2042
Quinebaug Solar	4	11	2022	2042
Gravel Pit Solar	50	70	2023	2043
Revolution Wind	400	1,717	2024	2044
Total	1,354	3,061	n/a	n/a

Note: Since this analysis was conducted, the Chinook Solar contract has been terminated.

C. The Gap to 100% Renewables

The "gap" to 100% renewable energy in 2030 is the difference between the state's projected total load in 2030 (Section II.A) and the renewable generation that Rhode Island has already

2 REG information based on National Grid's Open Enrollment Reports, available at: http://www.ripuc.ri.gov/eventsactions/docket/NGrid-REG-EnrollmentRepts.html. Information on long-term contracts and virtual and direct net metering provided by OER and National Grid.

procured and that will be online in 2030 (Section II.B). This gap, which amounts to 4,600 GWh in 2030, is illustrated in Figure 3 of the Report.

III. Above-Market Ratepayer Cost Impacts – Renewable Resource Costs and Value

The first of two primary criteria used to characterize the renewable electricity technologies and portfolios considered is the above-market ratepayer cost. The above-market cost is based primarily on the acquisition cost of the renewable generation resources and their energy and capacity market value.

A. Renewable Resource Costs

The resource acquisition cost ranges used for these analyses are illustrated in Figure 6 of the Report; these were reviewed and refined with feedback from stakeholders and developers. These cost ranges are based largely on publicly available contract prices for recently acquired renewable resources through renewable procurements and programs across New England. We adjusted the contract prices to put them on a common basis, accounting for differences in economic life, price escalation terms, and online year, as well as the phase out of federal tax credits. The Levelized Cost of Energy (LCOE) for each resource was calculated by finding total value of the energy, RECs, Production Tax Credit (PTC) for wind resources, Investment Tax Credit (ITC) for solar resources, and capacity revenues in 2020 dollars. Most of the prices paid for renewable resources reflected similar conditions: contract for energy and RECs, a lifespan of 20 years, price escalation equal to inflation rate (2.5%), and the availability of either the PTC and ITC. Differences from these conditions are noted in the "Comments" column of tables 4 and 5 below for land-based and offshore wind; all the wholesale solar resources in table 6 had standardized contract conditions.

Due to the complete phase out of the PTC and the decrease of the ITC to 10% by 2023, we added back the value of the tax credits to each resource's contract price to inform the likely costs of future procurements. The PTC yearly contribution applies for the first 10 years a project is online and is calculated by:

$$\text{Yearly contribution} = \text{PTC Value in first year of construction (e.g. \$10 in 2019)} * \text{Inflation rate (2.5\%)} \wedge (\text{Online year} - \text{First year of construction})$$

If the expected online date is in the last two months of the year (November or December) we report the following calendar year as the online year.

To determine the ITC contribution, we used the average of the ITC values in the years procured solar projects were scheduled to come online (2019-2023), as shown in **TABLE 3**.

TABLE 3: ITC VALUE OF SOLAR

Year	2019	2020	2021	2023	2023	Average
ITC Value	30%	26%	22%	10%	0%	**18%**

Thus, the ITC contribution was calculated as 18% of the cost of each solar project. This does not include the 2020 extension of the solar Investment Tax Credit.[3]

We also added to the contract price the value of capacity revenues to account for changes in market rules. We assumed that the resources would expect to receive their full capacity value by entering the market through the renewable exemption that existed at the time, which resulted in an estimated capacity value of $6-7/MWh.

TABLE 4 list the specific New England renewable energy projects evaluated for land-based wind, offshore wind, and wholesale solar, and their adjusted LCOE values. Based on these reference points, we estimated that the 2019 LCOE of land-based wind is $82/MWh, $85/MWh for offshore wind, and $87/MWh for wholesale solar.

TABLE 4: LONG TERM LAND BASED WIND PROCUREMENTS

	Capacity (MW)	Online Year	Contract Price (Nominal $)	LCOE (2020$/MWh)	Adjustments to Contract Price
Copenhagen Wind	80	2019	$80	$79	2% escalation, 15 year life, added PTC value and capacity value
Cassadaga Wind	126	2021	$78	$88	2.54% escalation, added PTC value and capacity value

[3] Guide to the Federal Investment Tax Credit for Commercial Solar Photovoltaics, Solar Energy Technologies Office. Available at: https://www.energy.gov/sites/prod/files/2020/01/f70/Guide%20to%20the%20Federal%20Investment%20Tax%20Credit%20for%20Commercial%20Solar%20PV.pdf

TABLE 5: LONG TERM OFFSHORE WIND PROCUREMENTS

	Capacity (MW)	Online Year	Contract Price (Nominal $)	LCOE (2020$/MWh)	Adjustments to Contract Price
Vineyard Wind (Facility 1)	400	2022	$74	$82	Added PTC value and capacity value
Vineyard Wind (Facility 2)	400	2023	$65	$74	Added PTC value and capacity value
Revolution Wind	704	2024	$98	$85	No escalation, added PTC and capacity value
Mayflower Wind	804	2025	$58	$65	Added PTC and capacity value

TABLE 6: LONG TERM WHOLESALE SOLAR GENERATION PROCUREMENTS

	Capacity (MW)	Online Year	Contract Price (Nominal $)	LCOE (2020$/MWh)	Adjustments to Contract Price
Woods Hill Solar	20	2019	$99	$120	Added ITC and capacity value
Hope Farm Solar	20	2020	$94	$130	Added ITC and capacity value
Sanford Airport Solar	49	2021	$79	$100	Added ITC and capacity value
Chinook Solar	30	2022	$82	$101	Added ITC and capacity value
Farmington Solar	49	2022	$85	$105	Added ITC and capacity value
Quinebaug Solar	49	2022	$89	$110	Added ITC and capacity value
Gravel Pit Solar	50	2023	$53	$68	Added ITC and capacity value

Note: After this analysis was conducted, the Chinook Solar contract was terminated.

For the LCOE of retail solar, we relied on contract prices for solar resources through the Renewable Energy Growth program. These range from about $200/MWh to $300/MWh for solar resources less than 250 kW, and are generally $130/MWh to $150/MWh for solar resources over 1 MW (1,000 kW), as shown in **TABLE 7**. We relied on the most recent allocation of capacity across the RE Growth solar size categories, shown in **TABLE 8,** to develop a blended retail solar cost estimate of $178/MWh for retail solar.

TABLE 7: REG PROGRAM AVERAGE CONTRACT PRICES (RETAIL SOLAR)

	Contract Price (nominal $/MWh)			LCOE (2020$/MWh)			Adjustments to Contract Price
	2018	2019	2020	2018	2019	2020	
Small-Scale (1-25 kW DC)	n/a	n/a	$297	n/a	n/a	$302	No escalation, added ITC and capacity value
Medium-Scale Solar (26-250 kW DC)	$231	$231	$199	$246	$240	$203	No escalation, added ITC and capacity value
Commercial-Scale Solar (251-999 kW DC)	$134	$171	$185	$143	$178	$188	No escalation, added ITC and capacity value
Large-Scale Solar (1,000-5,000 kW DC)	$145	$128	$127	$154	$133	$129	No escalation, added ITC and capacity value

TABLE 8: REG PROGRAM 2020 ANNUAL ENROLLMENT TARGET

	Nameplate Capacity (MW_{DC})	% of Total Capacity
Small-Scale (<25kW)	6.95	16%
Medium-Scale (26-250 kW)	3	7%
Commercial-Scale (251-999 kW)	11.2	26%
Large-Scale (1,000-5,000 kW)	21.3	50%

Note: Total does not add to 100% due to independent rounding. Source: National Grid, Rhode Island Renewable Energy Growth Program, available at: https://ngus.force.com/s/article/Rhode-Island-Renewable-Energy-Growth-Program

The resource acquisition costs we developed for the ratepayer above-market cost analysis also accounts for future transmission and distribution system interconnection and upgrade costs. These interconnection and system upgrade cost estimates are based on costs recently observed for renewable resources, recent trends in interconnection costs, the outlook for future system upgrade needs, and feedback from renewable developers and stakeholders. The system upgrade cost assumptions utilized in the analysis are summarized in **TABLE 9**. We assumed a range of system upgrades costs in the resource cost projection to reflect the uncertainty in the system upgrade costs. In the Low Resource Cost scenario, we assumed no increase in system upgrade costs (i.e., upgrade costs are accounted for in the reference points noted above in the range of the estimated Current Projects costs in Table 9). In the High Resource Cost scenario, we relied on the high end of the range of increased system upgrade costs (Future Projects row of Table 9). For the Base Resource Cost we added half of the Increased Costs to the reference costs based on Current Projects.

TABLE 9: SYSTEM UPGRADE COST ASSUMPTIONS

System Upgrades	Offshore Wind	Land-Based Wind	Solar
Current Projects	$8-14/MWh based on ISO-NE Feasibility Study upgrade costs and assuming 10% of total capital costs for offshore transmission (from Orsted)	$3/MWh based on assumed $100/kW of local upgrades to interconnect to existing network	$12/MWh based on 2018-2019 average costs of $207/kW from National Grid costs
Future Projects	$24-28/MWh based on estimated $3.9-4.4B to interconnect the next 3.6 GW, or $1,100-1,200/kW (Anbaric)	$20-39/MWh based on $750-$1,500/kW from ISO-NE studies of accessing Maine wind	$23-34/MWh based on range of 2020 projected costs of $400-600/kW
Increased Costs (Future – Current)	$10-15/MWh	$17-37/MWh	$11-22/MWh

Sources and notes: *Offshore Wind*: "Offshore Transmission in New England: The Benefits of a Better-Planned Grid", prepared by The Brattle Group for Anbaric, May 2020. ISO-NE Feasibility Study costs are based on the summary in the Brattle report for Anbaric (p. 15). *Land-Based Wind*: "The Coming Electrification of the North American Economy: Why We Need a Robust Transmission Grid", prepared by The Brattle Group for WIRES, March 2019. ISO-NE studies of accessing Maine wind: 2016/2017 Maine Resource Integration Study (March 2018), Second Maine Resource Integration Study: Results (November 2019), 2016 Economic Studies: Preliminary high order of magnitude transmission development costs (October 2016). *Solar*: based on analysis of data provided by National Grid.

Resource costs projections over time through 2030 were developed based on the available reference points as outlined above, and using long-term cost trends from NREL's Annual Technology Baseline (ATB) to project changes in costs over time.[4] To reflect the evolving uncertainty in resource acquisition costs, high and low cost projections were developed based on the Conservative and Advanced cost trends in NREL's ATB, shown in **TABLE 10**.

[4] NREL Annual Technology Baseline 2020, available at: https://atb.nrel.gov/electricity/2020/data.php. Assumed a Capital Recovery Period of 20 years and used the "R&D Financials" assumption. Land-based wind cost projections are based on Class 9 cost trend, offshore wind cost projections are based on Class 1 cost trend, wholesale solar cost projections are based on the Utility (Seattle) cost trend, and retail solar cost projections are based on the Commercial PV (Seattle) cost trend.

TABLE 10: NREL FORECASTED AVERAGE ANNUAL (REAL) COST DECLINE, 2020-2030

	NREL Scenario		
Resource	**Conservative**	**Moderate**	**Advanced**
Land-Based Wind	-2.4%	-3.8%	-7.5%
Offshore Wind	-1.5%	-4.3%	-6.1%
Wholesale Solar	-1.3%	-5.3%	-7.8%
Retail Solar	-1.1%	-5.7%	-8.7%

In converting generating capacity to energy, we used the capacity factors shown in **TABLE 11**.

TABLE 11: CAPACITY FACTORS

Resource	Capacity Factor
Land-Based Wind	36%
Offshore Wind	52%
Wholesale Solar	16%
Retail Solar	14%

Source: Wind capacity factors based on ISO-NE average historical hourly generation profiles. Solar capacity factors from "Rhode Island Renewable Energy Growth Program: 2020 Ceiling Price Recommendations to DG Board, Sustainable Energy Advantage, September 23, 2019".

B. Resource Market Value

The resource market value consists of energy market revenues, capacity market revenues and REC revenues. *Section III.A – Resource Market Value* of the Report describes the sources and assumptions used to derive the market revenues by resource. The energy market revenues were estimated using Brattle's GridSIM model, which projects annual generation mix, capacity mix, and hourly market prices over time to 2040, based on state environmental mandates and renewable resource costs as developed above. More information about the GridSIM model is provided in Section VI of this Technical Support Document.

C. Ratepayer Above-Market Cost of Technology Bookends and Technology Portfolios

To help illustrate the impacts of the candidate renewable technologies, we define a Technology Bookend corresponding to each of the four primary candidate technologies, Land-Based Wind, Offshore Wind, Wholesale Solar and Retail Solar. A given Technology Bookend consists of enough of the given resource type to fill the entire renewable energy gap with that technology – i.e., to achieve the 100% renewable electricity goal by adding only that technology on top of Rhode Island's existing and committed resources. In addition, we defined a number of Technology Portfolios that consist of various combinations of these four primary renewable technologies. The overall Above-Market Cost of each of these Bookends and Portfolios is presented in the Report. It consists of the resource acquisition cost minus the market value of the energy and capacity of the resource, with an adjustment to reflect the purchase or sale of market RECs as necessary to account for temporary deviations from an assumed RES requirement trajectory prior to 2030, reaching 100% in 2030.

IV. Economic Impact Analysis

A. Economic Impact Modeling

The second primary criterion used to characterize the impact of renewable electricity technologies and portfolios is their impact on Rhode Island's economy, as measured by state gross domestic product (GDP) and in-state employment. These economic impacts were estimated using NREL's JEDI models[5] and the IMPLAN model[6].

1. JEDI Models

Developed by the National Renewable Energy Laboratory (NREL), The Jobs and Economic Development Impact (JEDI) models estimate the economic impacts of constructing and operating various types of power generation plants in Rhode Island, based on industry data and norms. For this Report, the JEDI models for offshore wind, land-based wind, and photovoltaic generators, which included distributed and utility solar, were used. The JEDI model is used to break down the total cost of building and operating a generator of a particular type into granular categories, such as the cost of buying new equipment or labor cost, and identifies how much of the spending for each category is local to Rhode Island. We used JEDI data to break down the total capital costs of each technology into these JEDI categories, and then mapped these categories to IMPLAN sectors.

2. IMPLAN

Impact Analysis for Planning (IMPLAN) is a commercial input-output model, widely used to measure the impacts of regulatory changes and major infrastructure investments. To measure the impact of alternative types and quantities of new renewable generation, such as wind or solar, on Rhode Island's economy, we measured the economic impact of the construction and operation of local resources in Rhode Island. We also measured the economic impacts related to their effect on electricity costs to ratepayers, resulting from the above-market ratepayer cost analysis described above. The construction and operating expenditures for each technology, and their effect on delivered electricity

[5] More information about the JEDI models can be found on NREL's website at https://www.nrel.gov/analysis/jedi/.
[6] More information about IMPLAN can be found at https://implan.com/.

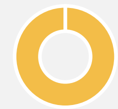
costs for consumers, were used as inputs for the IMPLAN model. IMPLAN determines the resulting impact of these factors on Rhode Island's state GDP and in-state employment.

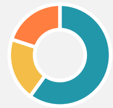
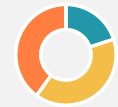
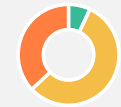
B. Economic Impact Results

1. Summary of Economic Impacts – Technology Bookends and Technology Portfolios

FIGURE 2 summarizes the estimated GDP and employment impacts for each of the Technology Bookends, and for the Technology Portfolios (combinations of different technologies). As described in the Report, these impacts are measured relative to meeting the 100% renewable goal with market REC purchases, at an assumed reference REC price of $30/MWh (high and low REC prices of $45/MWh and $15/MWh are also considered, as illustrated in Figures 20 and 23 of the Report).

FIGURE 2. GDP AND EMPLOYMENT IMPACT OF TECHNOLOGY BOOKENDS AND PORTFOLIOS
(BASE CASE COST ASSUMPTIONS AND BASE REC PRICE ASSUMPTION)

Impact	1. Land-Based Wind	2. Offshore Wind	3. Wholesale Solar	4. Retail Solar
Resource Composition				
Construction (In-State Only)				
Expenditure ($M)	n/a	$4,049	$3,525	$6,887
NPV of GDP Impact ($M)	n/a	$802	$882	$3,146
Jobs Impact (job-years)	n/a	8,550	8,582	33,539
O&M (In-State Only)				
Expenditure ($M)	n/a	$2,358	$934	$1,346
NPV of GDP Impact ($M)	n/a	$289	$280	$404
Jobs Impact (job-years)	n/a	4,331	1,589	2,289
Above Market Cost				
Ratepayer AMC ($M)	$1,026	$812	$1,091	$4,793
NPV of GDP Impact ($M)	-$547	-$419	-$594	-$2,665
Jobs Impact (job-years)	-8,805	-6,966	-9,361	-41,123
Total (In-State)				
Expenditure ($M)	**n/a**	**$6,407**	**$4,460**	**$8,233**
NPV of GDP Impact ($M)	**n/a**	**$672**	**$568**	**$885**
Jobs Impact (job-years)	**n/a**	**5,915**	**810**	**-5,296**
Total (Out-of-State)				
Expenditure ($M)	**n/a**	**n/a**	**n/a**	**n/a**
NPV of GDP Impact ($M)	**-$547**	**-$419**	**-$594**	**n/a**
Jobs Impact (job-years)	**-8,805**	**-$6,966**	**-$9,361**	**n/a**

Impact	5. Max OSW, plus Wholesale Solar	6. Max OSW, RE Programs Maintained	7. Robust OSW, RE Programs Maintained	8. Robust OSW, RE Programs Doubled	9. Incremental OSW, RE Programs Doubled	10. Solar Heavy, Some LBW, No new OSW
Resource Composition						
Construction (In-State Only)						
Expenditure ($M)	$3,864	$4,544	$4,427	$5,103	$4,986	$4,820
NPV of GDP Impact ($M)	$845	$1,303	$1,475	$1,768	$1,777	$1,661
Jobs Impact (job-years)	8,620	13,670	15,340	18,642	18,597	17,260
O&M (In-State Only)						
Expenditure ($M)	$1,148	$1,347	$1,307	$1,505	$1,465	$1,323
NPV of GDP Impact ($M)	$293	$318	$313	$338	$334	$334
Jobs Impact (job-years)	3,328	3,470	2,889	3,030	2,449	1,735
Above Market Cost						
Ratepayer AMC ($M)	$938	$1,687	$1,733	$2,478	$2,524	$2,459
NPV of GDP Impact ($M)	-$496	-$914	-$945	-$1,361	-$1,391	-$1,391
Jobs Impact (job-years)	-8,050	-14,476	-14,872	-21,258	-21,654	-21,100
Total (In-State)						
Expenditure ($M)	$5,012	$5,892	$5,734	$6,608	$6,451	$6,143
NPV of GDP Impact ($M)	$642	$707	$844	$745	$720	$604
Jobs Impact (job-years)	3,899	2,663	3,357	414	-608	-2,105
Total (Out-of-State)						
Expenditure ($M)	$0	$1,802	$1,790	$3,580	$3,568	$2,561
NPV of GDP Impact ($M)	-$496	-$196	-$231	$66	$32	-$72
Jobs Impact (job-years)	-8,050	-7,227	-7,670	-6,852	-7,295	-7,778

Note:

1. Construction Expenditures occur over the several years prior to operation; the particular time profile depends on the technology. O&M Expenditures occur during the operational life of a project, estimated to be 20 years for each of these technologies.
2. Total Expenditures reported here reflect the sum of in-state Construction and O&M expenditures (not discounted).
3. The land-based wind component of portfolios is always out-of-state, and the retail solar component is always in-state.

2. Detail on Economic Impacts – Technology Bookends and Technology Portfolios

The estimated economic impacts of each of the Technology Bookends and Technology Portfolios is illustrated below in a pair of figures, showing first the impact on Rhode Island GDP, and second the impact on in-state employment (expressed in job-years; a job-year is equivalent to a full-time job for one year, not discounted over time). Again, these impacts are relative to meeting the 100% renewable goal with market REC purchases at an assumed reference REC price of $30/MWh.

Where relevant, each figure shows the aggregate annual estimated impact of the Bookend/Portfolio assumed to consist entirely of in-state resources (solid line) and alternatively, assumed to consist entirely of out-of-state resources (dashed line). Captions on each figure show a single summary measure over time. For GDP, this summary measure is the net present value of the GDP impacts (NPV to 2020, in 2020 dollars). For the employment impact, it is the total number of net job-years over time (not discounted). Note that Land-Based Wind is considered only as an out-of-state resource, and Retail Solar is considered only as an in-state resource.

3. Economic Impact Results

FIGURE 3.1. TECHNOLOGY BOOKEND – LAND-BASED WIND – RHODE ISLAND GDP AND EMPLOYMENT IMPACT

Note: Land-based wind is considered only as an out-of-state resource because the quality of the Rhode Island wind resource does not support substantial quantities of land-based wind in state.

FIGURE 3.2. TECHNOLOGY BOOKEND – OFFSHORE WIND – RHODE ISLAND GDP AND EMPLOYMENT IMPACT

FIGURE 3.3. TECHNOLOGY BOOKEND – WHOLESALE SOLAR – RHODE ISLAND GDP AND EMPLOYMENT IMPACT

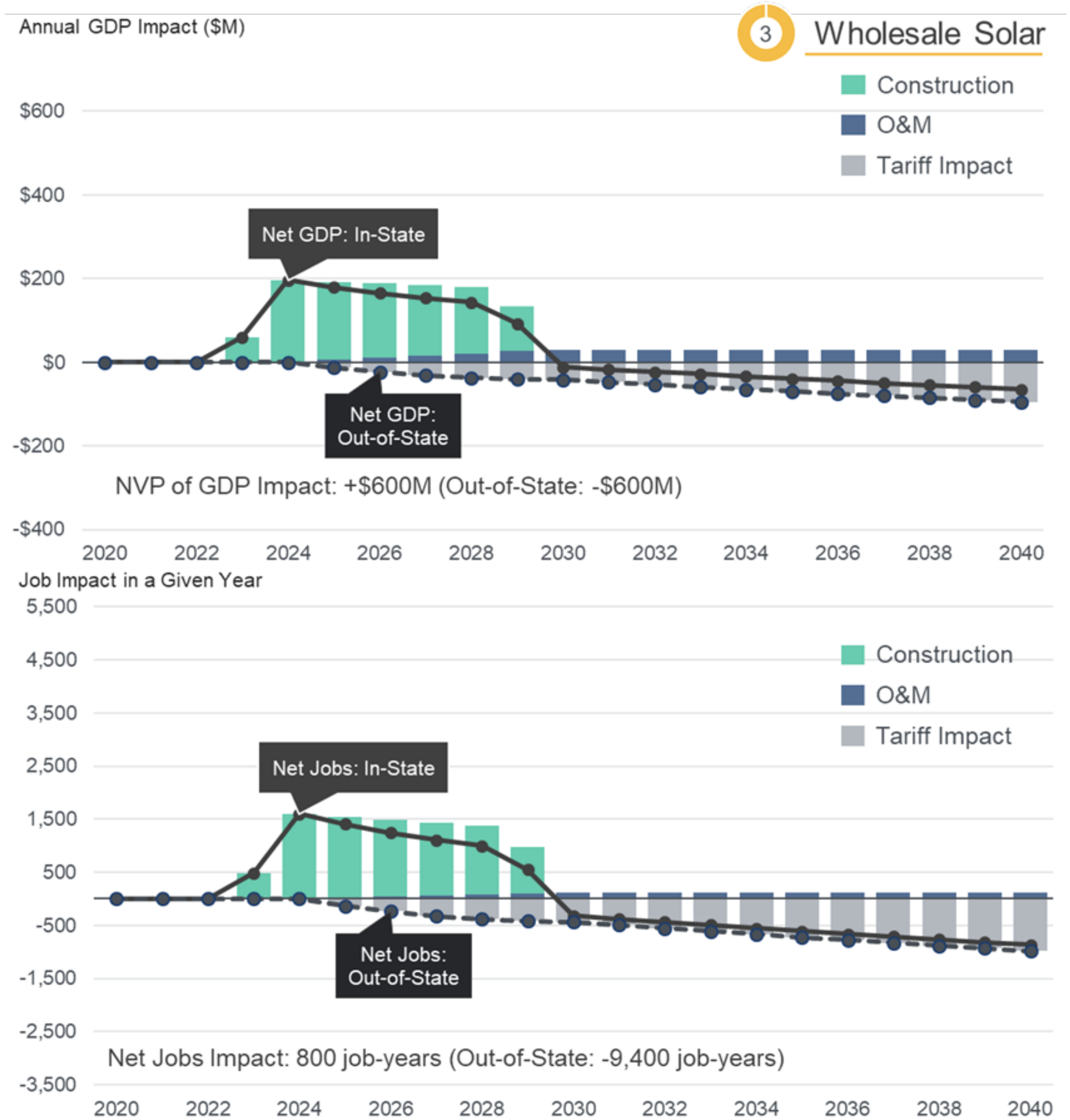
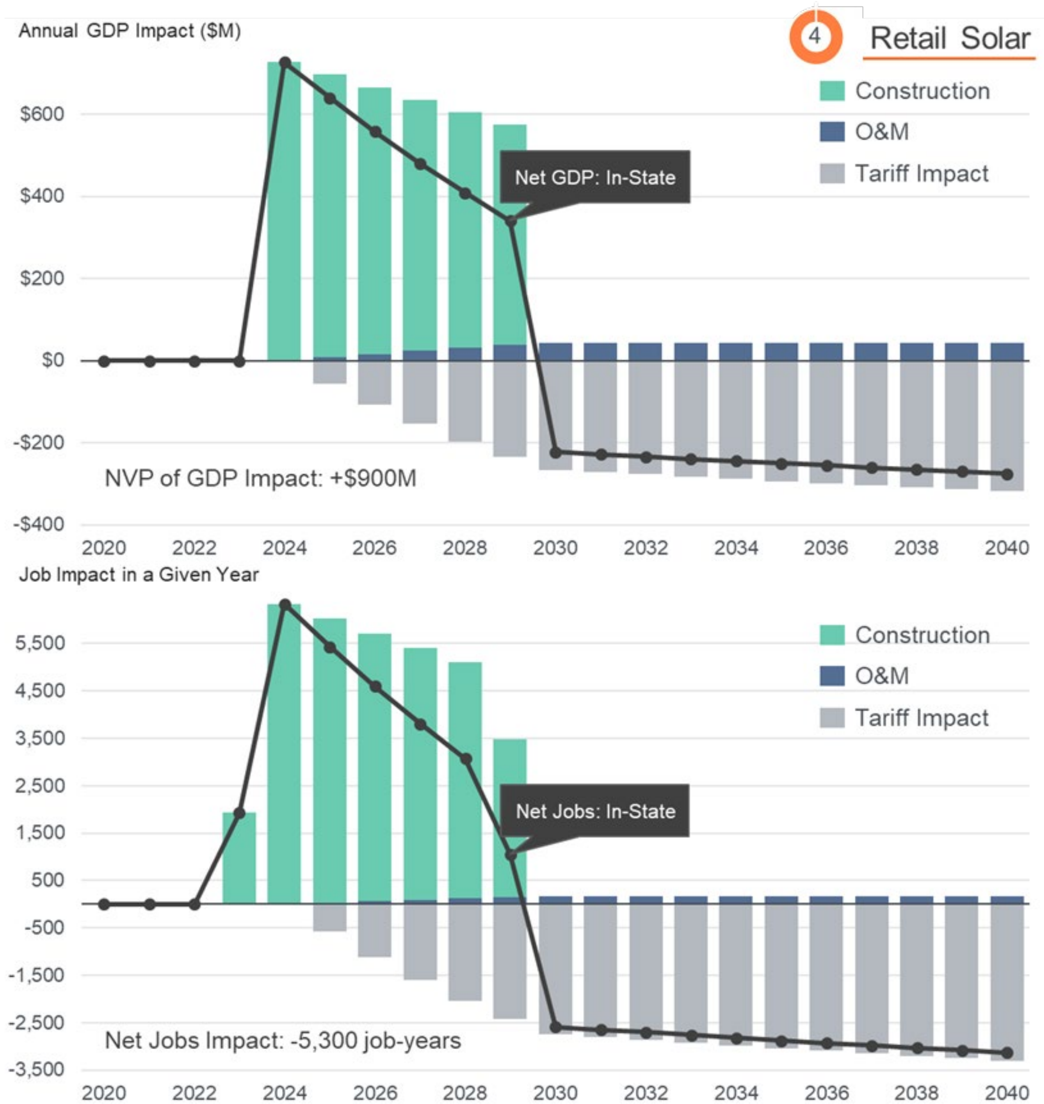


FIGURE 3.4. TECHNOLOGY BOOKEND – RETAIL SOLAR – RHODE ISLAND GDP AND EMPLOYMENT IMPACT



Note: Retail solar is considered only as an in-state resource, since only in-state projects are eligible for the Rhode Island programs that support retail solar.

FIGURE 3.5. TECHNOLOGY PORTFOLIO – MAX OFFSHORE WIND PLUS WHOLESALE SOLAR – RHODE ISLAND GDP AND EMPLOYMENT IMPACT

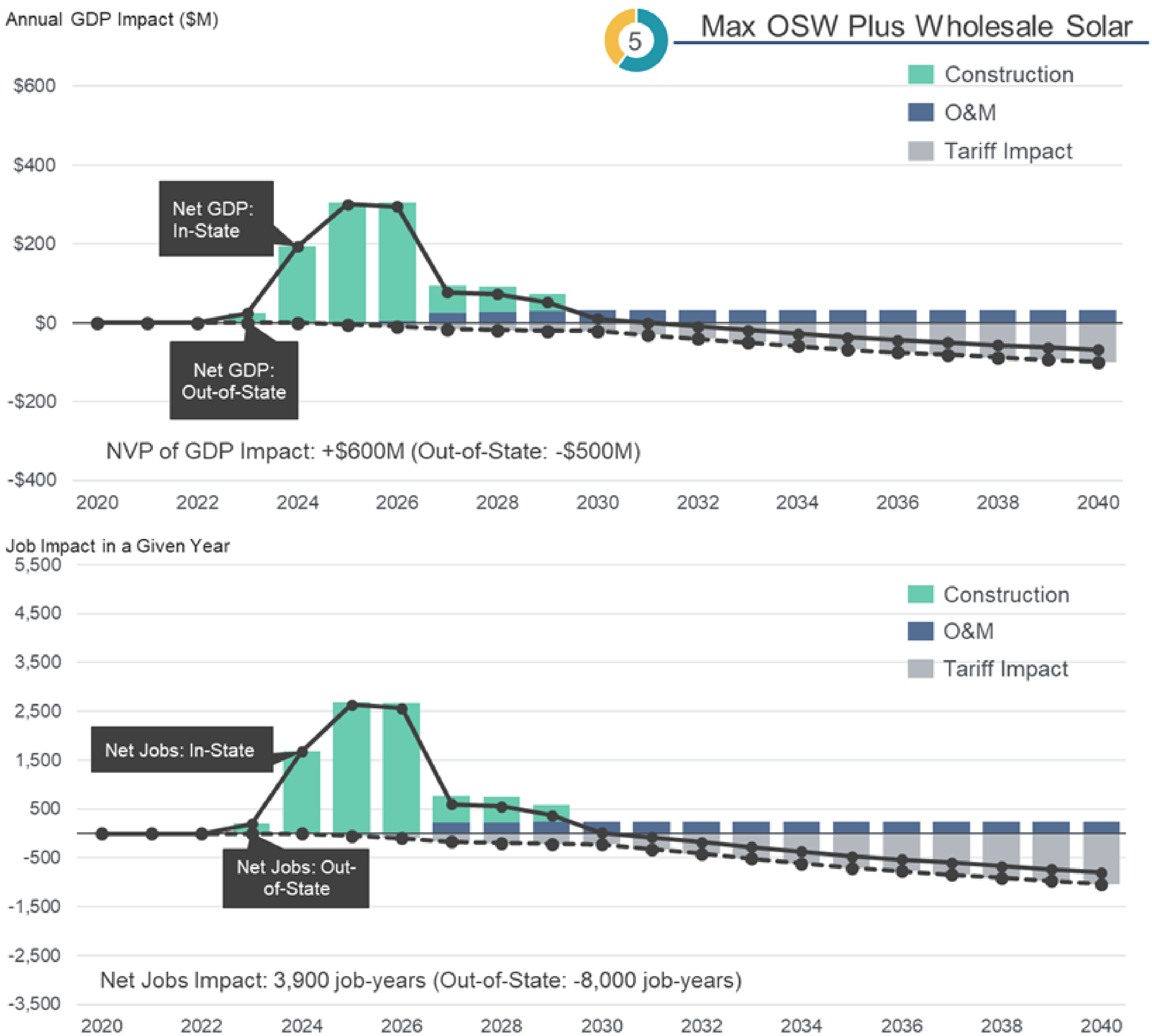
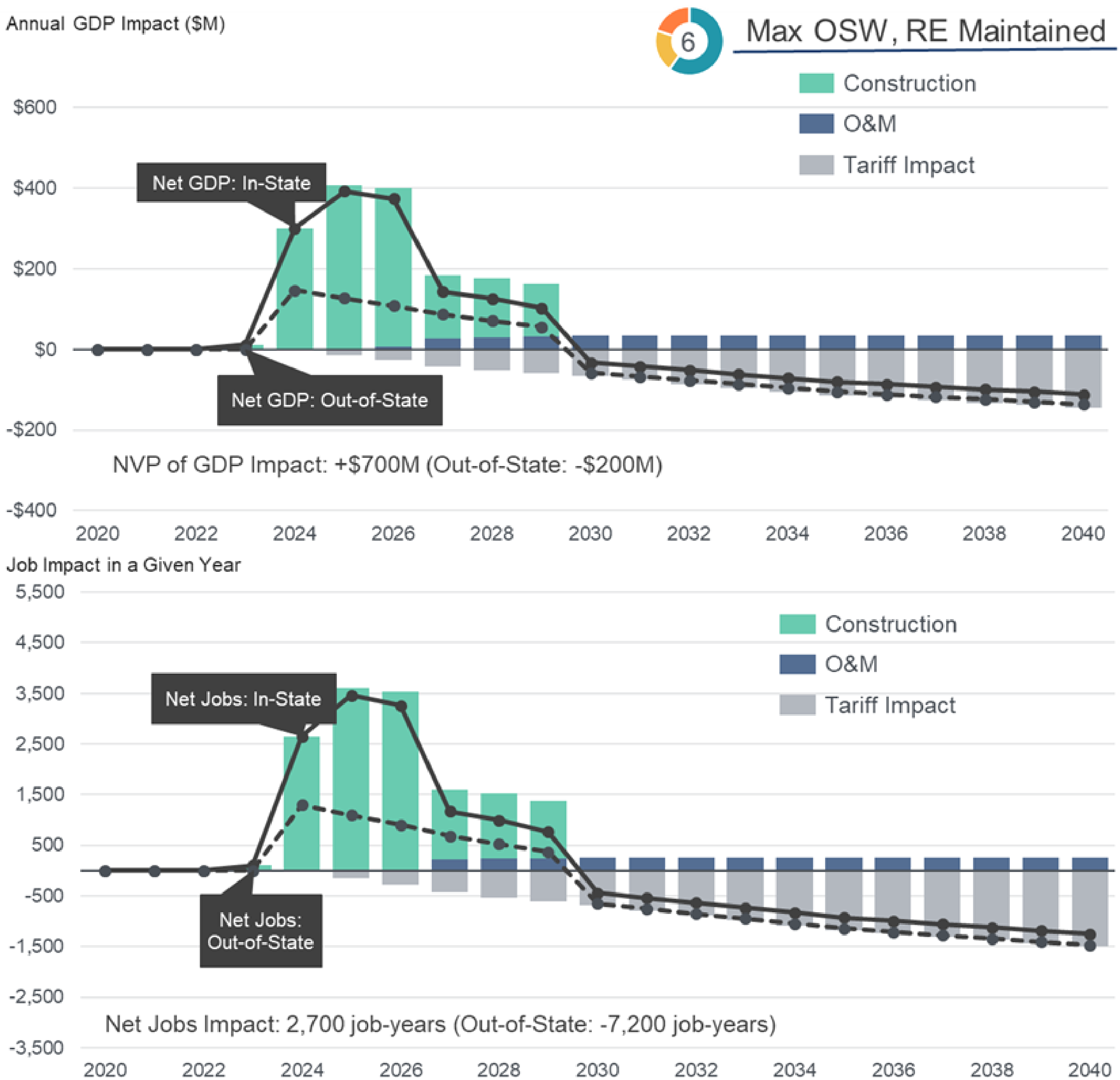
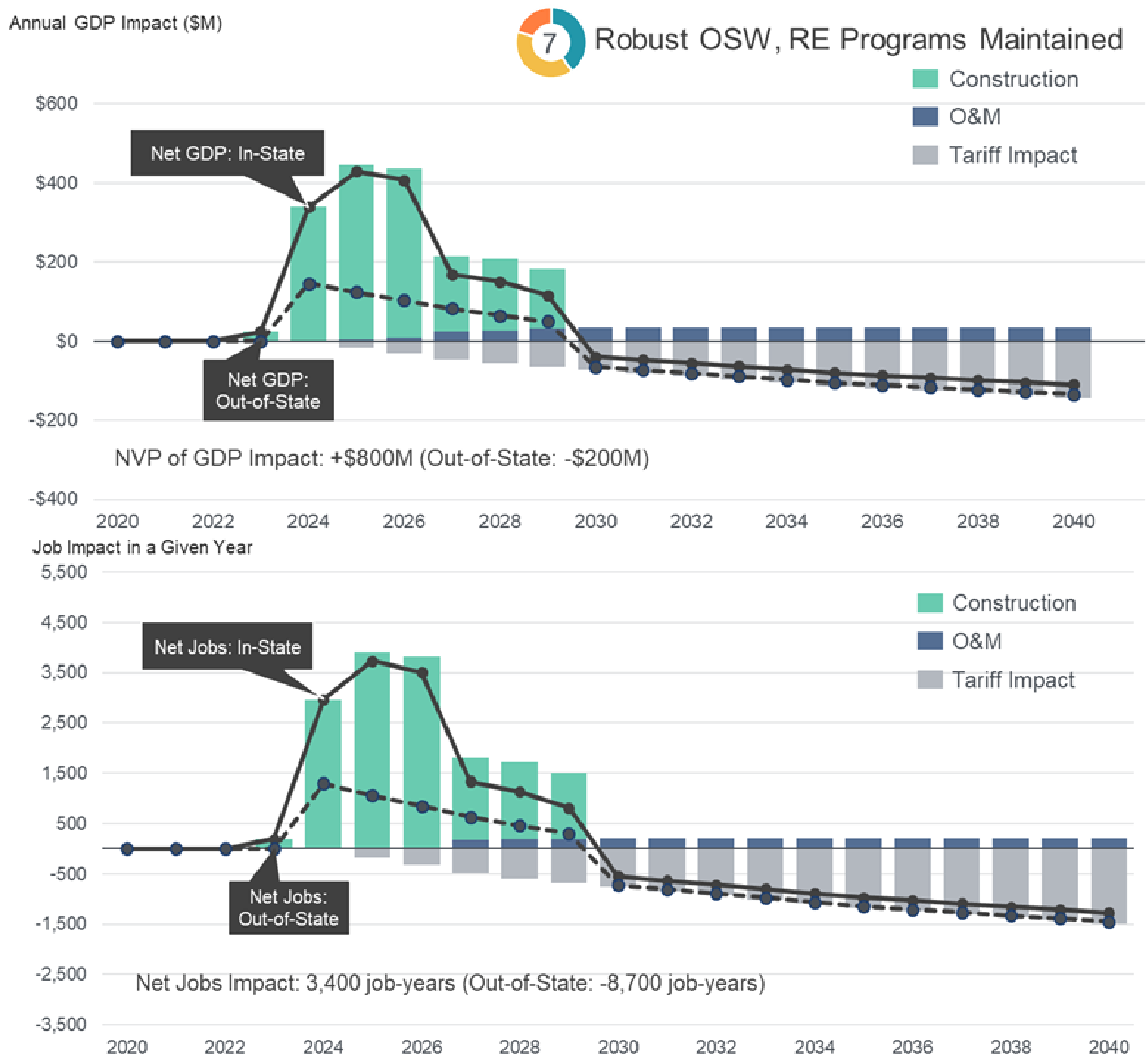


FIGURE 3.6. TECHNOLOGY PORTFOLIO – MAXIMUM OFFSHORE WIND PLUS RENEWABLE ENERGY PROGRAMS MAINTAINED – RHODE ISLAND GDP AND EMPLOYMENT IMPACT



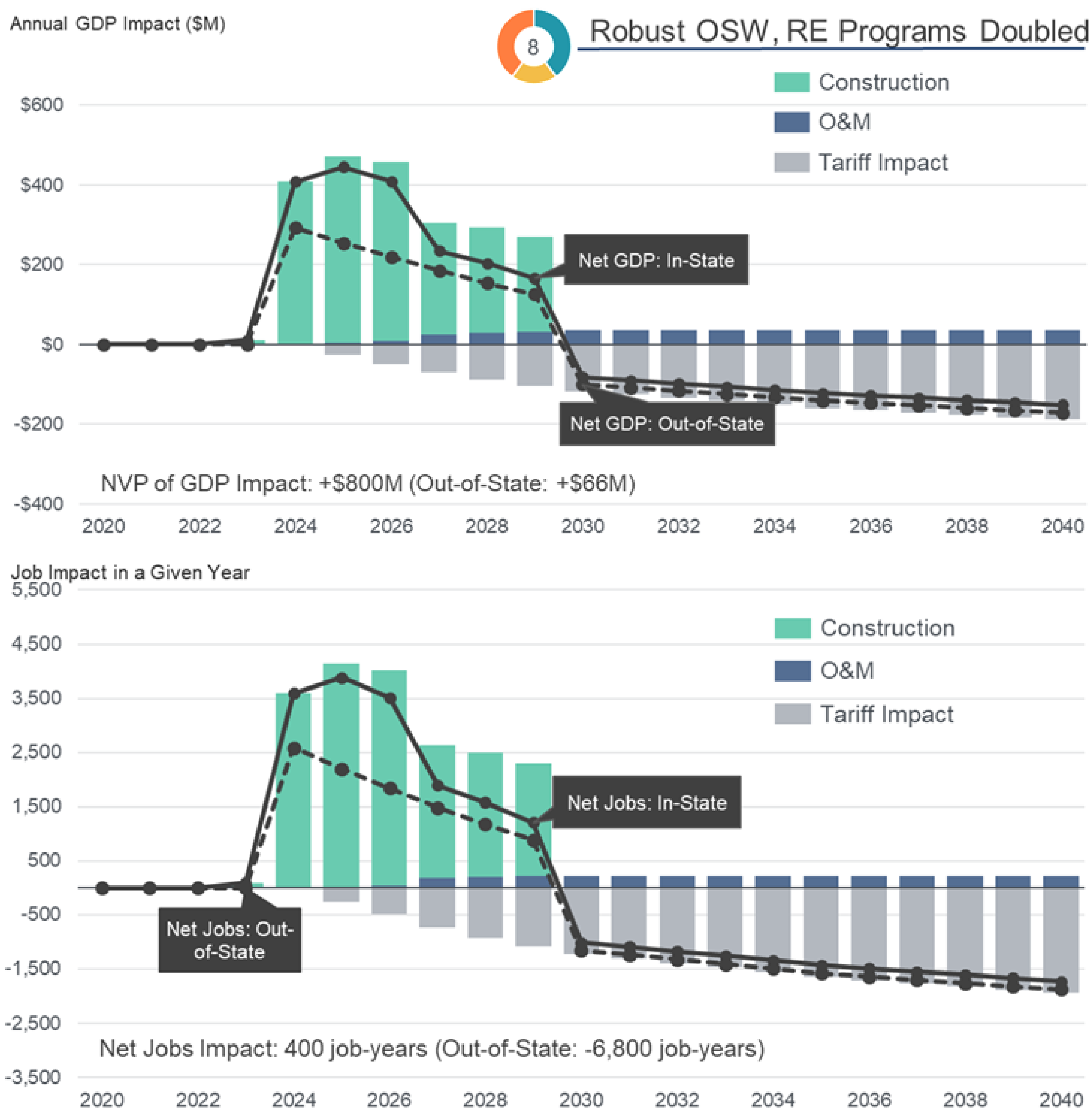
Note: The retail solar component of portfolios is always in-state.

FIGURE 3.7. TECHNOLOGY PORTFOLIO – ROBUST OSW, RE PROGRAMS MAINTAINED – RHODE ISLAND GDP AND EMPLOYMENT IMPACT



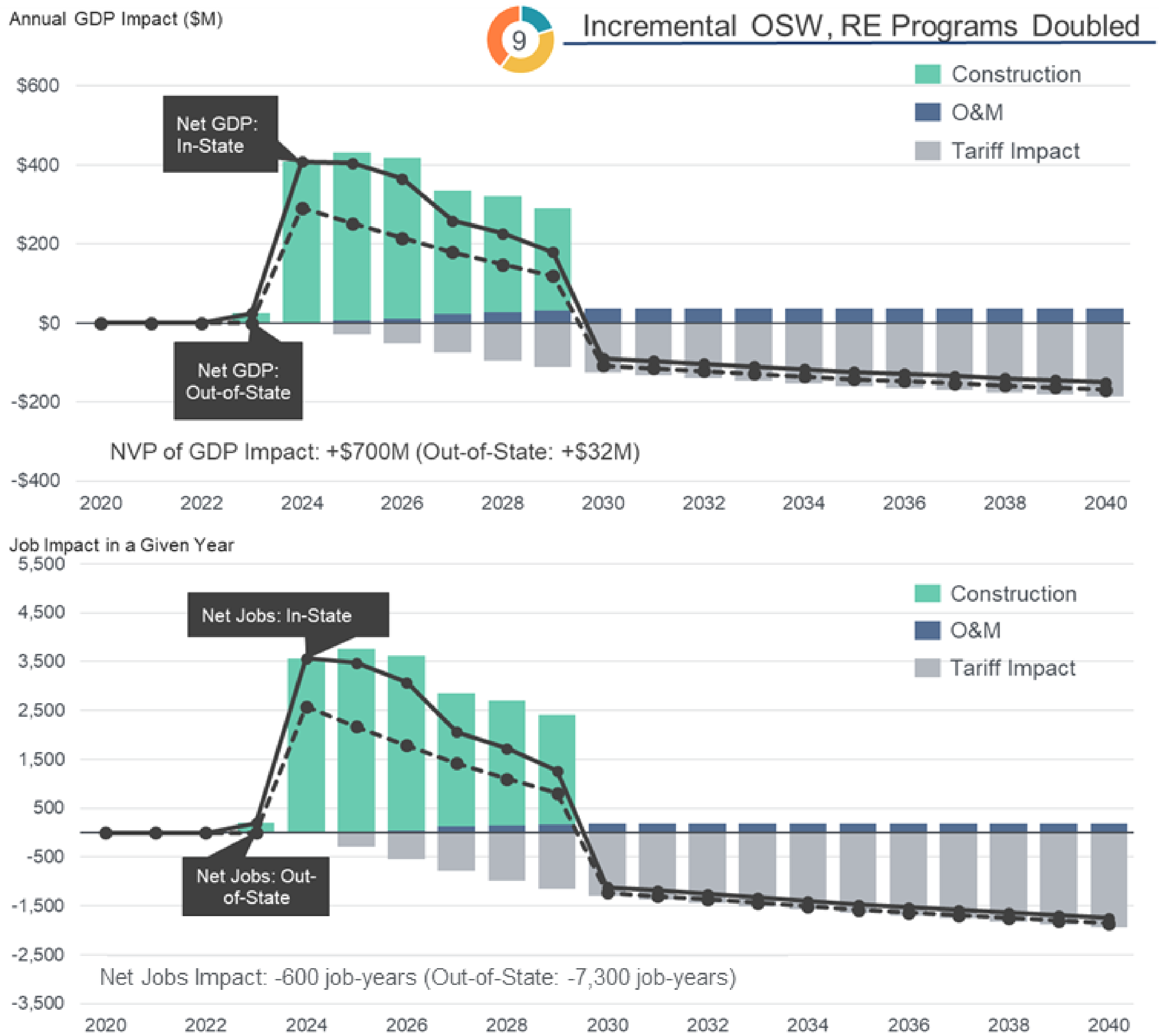
Note: The retail solar component of portfolios is always in-state.

FIGURE 3.8. TECHNOLOGY PORTFOLIO – ROBUST OFFSHORE WIND PLUS RENEWABLE ENERGY PROGRAMS DOUBLED – RHODE ISLAND GDP AND EMPLOYMENT IMPACT



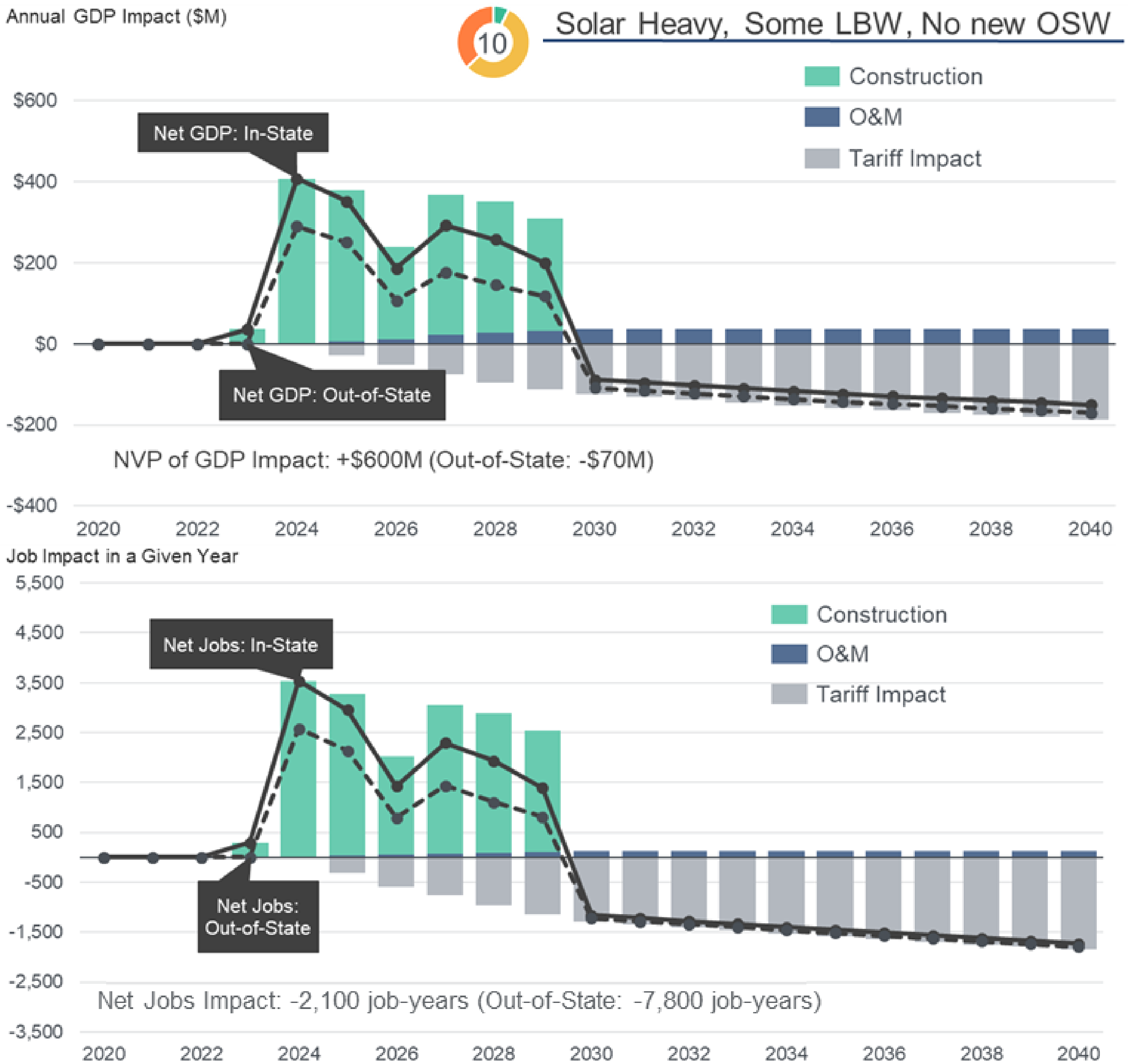
Note: The retail solar component of portfolios is always in-state.

FIGURE 3.9. TECHNOLOGY PORTFOLIO – INCREMENTAL OFFSHORE WIND, RENEWABLE PROGRAMS DOUBLED – RHODE ISLAND GDP AND EMPLOYMENT IMPACT



Note: The retail solar component of portfolios is always in-state.

FIGURE 3.10. TECHNOLOGY PORTFOLIO – SOLAR HEAVY, SOME LAND-BASED WIND, NO NEW OFFSHORE WIND – RHODE ISLAND GDP AND EMPLOYMENT IMPACT



Note: The land-based wind component of portfolios is always out-of-state, and the retail solar component is always in-state.

V. Greenhouse Gas Emissions Impact

As noted in the Report, this study did not focus on the emissions impacts of alternative ways to achieve 100% renewable electricity. Any alternative that achieves the 100% goal will have essentially the same GHG emissions impact, and thus emissions will not be a distinguishing factor among alternative pathways. Still, it is useful to put the emissions impact of the 100% goal into perspective. Rhode Island's existing RES requirement is 31% in 2030; this corresponds to about 2,400 GWh, using the Base Load Case electricity demand projection for 2030 (7,700 GWh). Increasing the renewable requirement from 31% to 100% in 2030 means displacing an additional 5,300 GWh of fossil-fired power with emission-free electricity in that year.

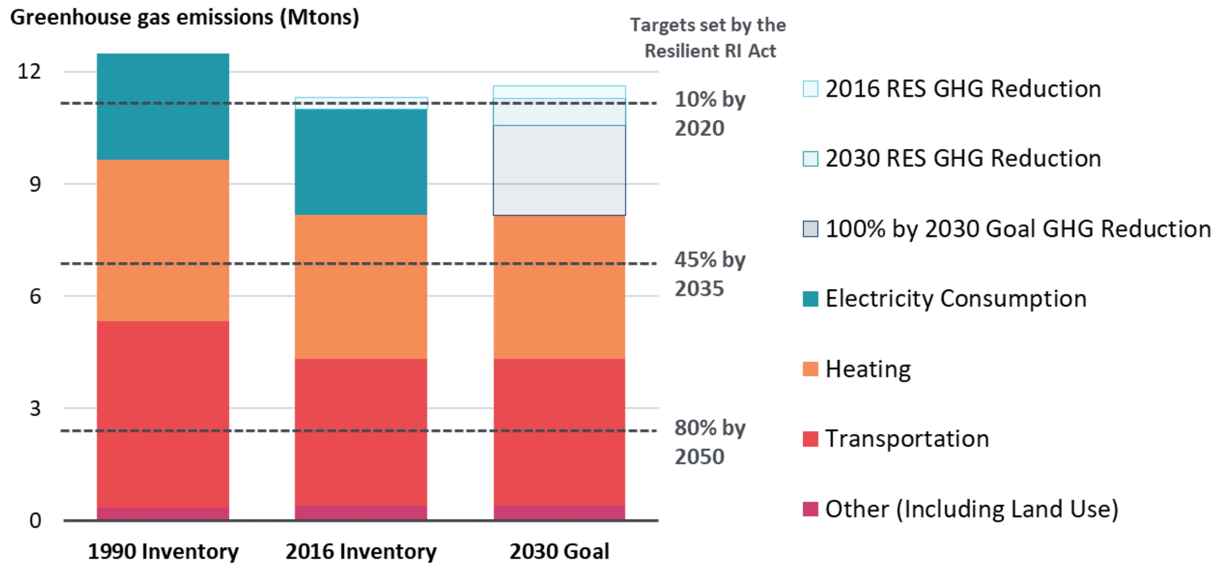
The annual emissions impact of this can be estimated using the current system marginal emission rate of 0.45 metric tons per MWh for the New England electric system.[7] At this emissions rate, the new 100% renewable goal will reduce GHG emissions by about 2.4 million tons CO_2 in 2030 (0.45 tons CO_2/MWh * 5,300 GWh * 1,000 MWh/GWh); this is beyond the reductions that would be achieved by the existing 2030 RES requirement.[8] To put this into the proper perspective, Rhode Island's long-term GHG emissions goal, established by the Resilient Rhode Island Act, is an 80% reduction by 2050, relative to the state's 1990 baseline GHG emissions of 12.48 million tons CO_2. Interim targets are 10% reduction by 2020 (which has been met) and 45% reduction by 2035. The 2.4 million tons additional reduction that will be achieved with 100% renewable electricity corresponds to 19% of the 1990 baseline – making this a very significant step toward the state's long-term emissions reduction goals, and providing the majority of the additional reductions needed to meet the 2035 interim target.[9] **FIGURE 4** shows that with the emissions reductions provided by achieving 100% renewable electricity, the additional reductions needed in other sectors will be only 1.3 million tons to meet the 2035 interim target.

7 ISO-NE 2018 Air Emissions Report, available at: https://www.iso-ne.com/static-assets/documents/2020/05/2018_air_emissions_report.pdf. Table 1-2 shows that the load weighted average CO_2 emissions rate for emitting locational marginal units (LMUs) is 971 lbs/MWh, which converts to 0.45 metric tons/MWh.

8 The difference between the existing 2030 RES and 100% is 5,300 GWh, slightly more than the 4,600 GWh gap between renewable energy installed by 2030 and 100%. This is because Rhode Island has already acquired and committed to renewables in excess of its 2030 RES requirement. See Figure 3 of the Report.

9 This estimate does not include the additional GHG emissions reductions that would occur in other sectors (transportation and heating) as a result of the modest amount of electrification assumed in those sectors by 2030.

FIGURE 4: EMISSIONS IMPACT OF 100% RENEWABLE ELECTRICITY IN 2030



Note: The 2016 and 2030 RES GHG Reduction components represent the GHG reduction from achieving the 2016 RES goal of 10% renewable energy, and the additional reductions from the 2030 RES goal of 31% renewable energy. The 100% by 2030 Goal GHG Reduction component represents the incremental GHG reduction from achieving 100% renewable electricity by 2030. GHG reductions from other sectors by 2030 are not represented here; 2016 values are repeated to illustrate additional reductions needed elsewhere in the economy to meet the targets of the Resilient Rhode Island Act. Source of 1990 and 2016 inventories: Rhode Island's 2016 Greenhouse Gas (GHG) Emissions Inventory Update, September 2019, available at: http://www.dem.ri.gov/programs/air/documents/righginvent16d-pres.pdf.

VI. GridSIM Model

A. Model Overview

The Grid Scenario Impact Model (GridSIM) model is Brattle's in-house capacity expansion and planning model designed specifically for analyzing highly decarbonized electric systems.[10] **FIGURE 5** below provides an overview of GridSIM's inputs, optimization, and outputs. GridSIM simulates hourly system operations and optimal resource investment and retirement over a multi-decade time horizon, while achieving reliability and environmental mandates. It produces hourly energy and ancillary service price projections, and how hourly, daily and seasonal patterns of energy market prices will be transformed by significant renewable additions over time, as well as storage resources, which are both encouraged by and help to mitigate some of the price extremes. These capabilities are key in the context of evaluating future energy revenues from renewable generation.

FIGURE 5: GRIDSIM INPUTS, OPTIMIZATION, AND OUTPUTS

Within each year modeled, GridSIM optimizes system operations at hourly granularity, enabling robust and highly detailed modeling of intermittent wind and solar resources and energy storage resources, which is necessary to accurately represent highly decarbonized systems. GridSIM analyzes twelve three-day representative periods to account for key chronological considerations that affect future operations and market prices. GridSIM co-optimizes the

[10] Additional information can be found at http://brattle.com/gridSIM.

resources necessary to meet demands for energy, ancillary services, and capacity. GridSIM's outputs include identification of the least cost resource mix to achieve decarbonization and reliability objectives, implied costs and energy prices, and hourly generation and transmission flows.

B. Model Assumptions

To analyze the future New England regional power system for this study, Brattle simulated every fifth year from 2020 to 2050 using GridSIM. The assumptions used in the model are consistent with assumptions developed in conjunction with Rhode Island stakeholders. Key assumptions are summarized below.

1. System Assumptions

- We modeled the ISO-NE system as a single zone energy market with no transmission constraints between zones.
- Imports are available from neighboring markets up to a fixed transfer capability that remains fixed over the timeframe of the analysis, as further described below.
- The GridSIM simulations reflect the current ISO-NE wholesale market rules and policies, including a sloped-demand curve for the capacity market, state-specific renewable energy goals, and long-term carbon policies.

2. Electricity Demand Assumptions

- New England-wide electricity demand for 2020 to 2029 is based primarily on ISO-NE's 2020 CELT forecast through 2030.[11] We adjusted the Rhode Island component of this New England electricity demand forecast to match the growth of energy efficiency and behind-the-meter solar PV penetration in National Grid's Rhode Island forecast, to be consistent with other aspects of our analysis.
- New England-wide electricity demand is extended to 2040 based on the recent study titled "Achieving 80% GHG Reduction in New England by 2050" that projected regional 2050 electricity demand, including new demand from widespread adoption of heating and transportation electrification, to achieve an 80% reduction in economy-wide emissions by 2050.[12]

[11] ISO-NE 2020 CELT Forecast, available at: https://www.iso-ne.com/system-planning/system-plans-studies/celt/.

[12] Jurgen Weiss and J. Michael Hagerty, Achieving 80% GHG Reduction in New England by 2050, prepared for Coalition for Community Solar Access, The Brattle Group, September 2019.

- The hourly shape of conventional (non-electrification) electricity demand is based on the actual ISO-NE 2018 hourly demand, with adjustments based on increased BTM generation. Details on the hourly electrification demand are available in the Technical Appendix of the recent study of regional 2050 electricity demand.[13]

3. Generator Assumptions

- The existing fleet of generation resources in ISO-NE is based on our review of generation resources included in the 2020 CELT report, ABB Energy Velocity Suite, and S&P Market Intelligence's generation database.
- Resources with announced retirement dates, including Bridgeport Harbor 3 (2021), Mystic 7, 8 & 9 (2022), and Yarmouth 1 & 2 (2023), were retired at those dates.
- New renewable resources were added based on the most recently announced programs and procurements, as shown in **TABLE 12**.

[13] Jurgen Weiss and J. Michael Hagerty, Achieving 80% GHG Reduction in New England by 2050: Technical Appendix, prepared for Coalition for Community Solar Access, The Brattle Group, September 2019.

TABLE 12: NEW RENEWABLE ENERGY RESOURCE ADDITIONS

Year	State	Name	Resource Type	Capacity (MW)
2020	Rhode Island	Hope Farms & Wood Hills	Solar	40
2020	Connecticut	TBD	Solar	165
2020	Massachusetts	SMART	Solar	230
2021	Massachusetts	Vineyard Wind 1	Offshore Wind	400
2022	Massachusetts	Vineyard Wind 2	Offshore Wind	400
2021-2022	Rhode Island & Massachusetts	Farmington, Quinebaug, Sanford Airport, Chinook	Solar	180
2022	Massachusetts	NECEC	Large Hydro	1,200
2023	Rhode Island	Revolution Wind	Offshore Wind	400
2023	Connecticut	Revolution Wind	Offshore Wind	304
2023	Connecticut	Gravel Pit	Solar	50
2024	Maine	TBD	Distributed Renewable Generation	375
2025	Massachusetts	SMART Program	Solar PV	2,970 (3,200 total)
2025	Massachusetts	Mayflower Wind	Offshore Wind	804
2025	Connecticut	Park City	Offshore Wind	804
2030	Connecticut	TBD	Offshore Wind	1,200
2030	Rhode Island	RE Growth Program	Solar	420
2035	Massachusetts	TBD	Offshore Wind	1,600

- Rising renewable portfolio standard (RPS) mandates are based on the aggregation of state renewable targets, which reach region-wide levels of about 28% in 2025, 43% in 2030, 48% in 2035, and 53% in 2040.
- The electric system is required to achieve 80% GHG reductions in 2040, as a proxy interim target for achieving long-term (mostly 2050) GHG emissions reduction goals set by the New England states.
- Renewable resource generation profiles are based on 2018 ISO-NE generation data.[14]
- New resource capital costs are consistent with the resource acquisition costs presented in Section III.A of the Report.

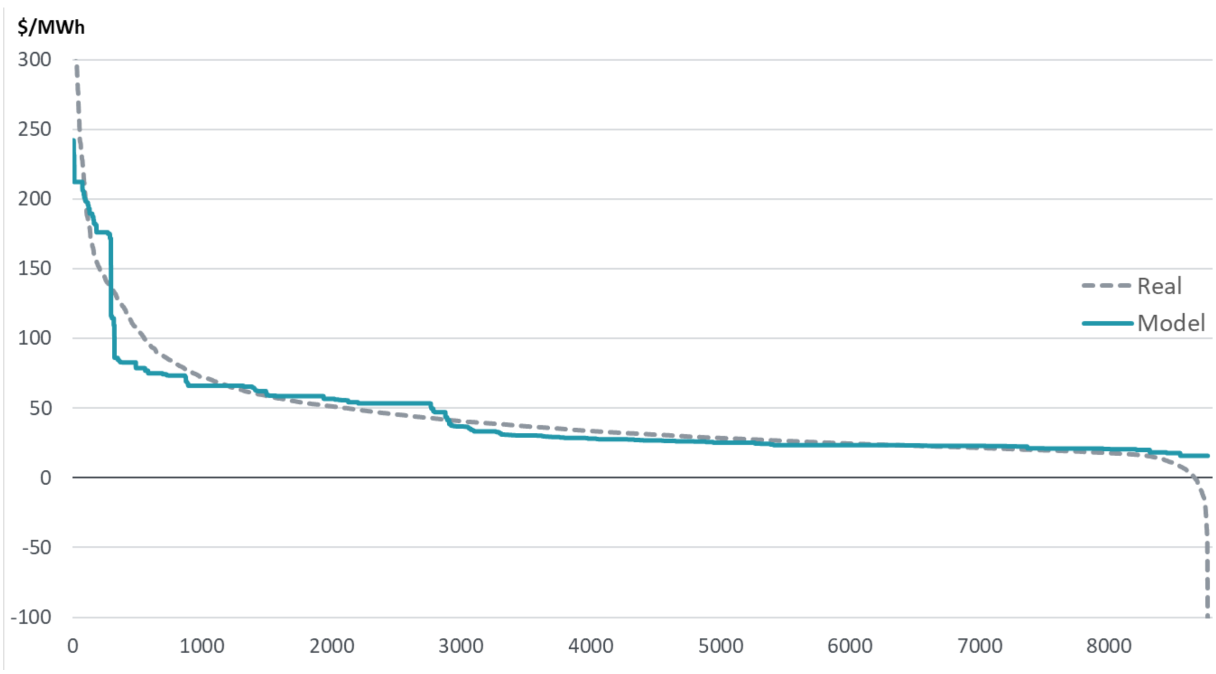
[14] ISO-NE, Operations Report, Daily Generation by Fuel Type, available at: https://www.iso-ne.com/isoexpress/web/reports/operations/-/tree/daily-gen-fuel-type

- Natural gas prices in the near term are based on NYMEX futures prices for the Algonquin Citygates hub. In the long term they are based on prices projected by the 2020 Annual Energy Outlook. We apply daily gas price variations to the monthly average prices based on 2018 gas prices.
- Imports from New Brunswick, Quebec, and New York are capped at the 2018 hourly imports and offer into the energy market at prices reflecting an efficient combined cycle natural gas plant, to account for the opportunity cost of the imports.

C. Rhode Island GridSIM Inputs and Results

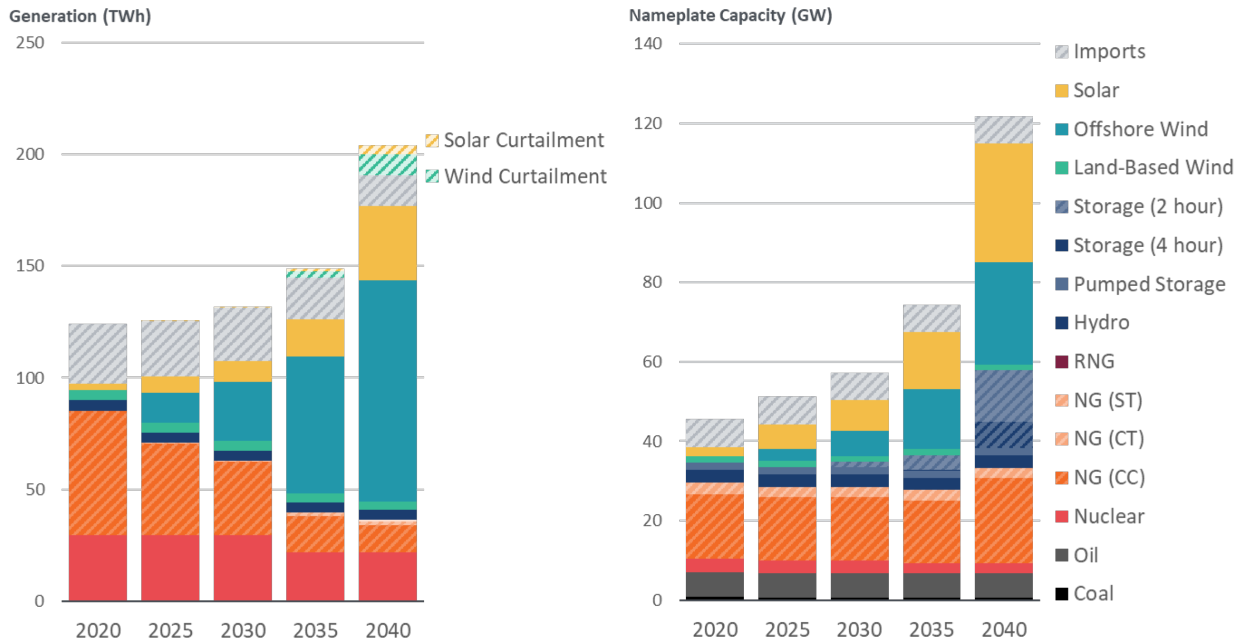
- We validated the model results by running a case with market conditions similar to 2018, including natural gas prices and generation resources, and comparing the resulting prices to actual historical prices. As shown in **FIGURE 6**, the model developed prices that are similar to the actual 2018 prices, with all-hour average prices within 5% of actuals.

FIGURE 6: GRIDSIM VALIDATION – 2018 HISTORICAL AND GRIDSIM MODEL PRICE DURATION CURVE COMPARSION



- The GridSIM simulations resulted in an outlook of future resources necessary for every fifth year from 2020 to 2040 to maintain system reliability and achieve renewable energy objectives at lowest cost to consumers. **FIGURE 7** below shows that 26 GW of offshore wind and 30 GW of solar will be necessary by 2040 as overall electricity demand and RPS requirements increase, primarily in the 2030 to 2040 timeframe. In 2040, renewables account for 71% of electricity generation (54% wind and 17% solar). In addition, 20 GW of battery storage will need to be added from 2030 to 2040 to balance the output of growing levels of renewable generation with load.

FIGURE 7: GRIDSIM RESULTS – NEW ENGLAND GENERATION AND CAPACITY OVER TIME



- As discussed in Section III.A of the Report, we estimated the energy market values of the renewable resource portfolios to fill the 100% renewable electricity gap based on the prices projected by GridSIM. Figure 8 of the Report illustrates the average annual energy price earned by each of the primary renewable technologies over time.