New England 2030 Power System Study

Demand and Resource Assumptions

May 15, 2009

This document contains the assumptions being developed by the New England states, with technical support from the ISO, for the New England Governors' 2009 economic study request. The study is for a future scenario of large-scale integration of renewable resources (i.e., wind) for a single year in the 20-year timeframe (around 2030). The level of wind integration is intended to be consistent with the assumptions in the ISO's wind integration study, which is being conducted in parallel with this economic study.

The assumptions include demand and supply levels for New England, representative future Installed Capacity Requirements (ICR), demand resource penetration, plug-in hybrid electric vehicle (PHEV) penetration, a Maine proposal for converting homes from oil to electric heat, the level of existing resources (generation, demand resources, and imports), four wind-integration cases, energy storage, retirement of older oil- and coal-fired generators, and expansion of interconnections with neighboring regions. The study will evaluate approximately 30 cases, including a base case (with additional wind resources and no unit retirements), an alternate base case (with additional natural gas-fired resources instead of additional wind resources), and multiple sensitivities. The study will evaluate a range for most assumptions (i.e., low, medium, and high).

The study approach is to evaluate a preferred future resource scenario. The approach is not to add resources to meet projections of future demand for electricity, and is not to add specific types of resources to meet any particular state or federal policy objectives, but rather to evaluate specific economic and environmental characteristics of each scenario.

Additional information is contained in several attachments.

Attachment 1:	An initial list of cases to be evaluated as part of the study
Attachment 2:	Assumptions for the ISO's Wind Integration Study
Attachment 3:	Maine oil-heat to electric-heat conversion assumptions
Attachment 4:	Oakridge National Laboratory assumptions for penetration of PHEVs

Regional Peak Demand

2030 Summer 50/50 Peak – 34,500 MW[1] (Gross) will be used for this single year snapshot

- Load forecast is based on the RSP09 forecast extrapolated to 2030; does not include adjustments for Energy Efficiency (EE) measures

Table 1: Projected Peak Demand

Year	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	**2030**
Peak (MW)	30,960	31,200	31,500	31,800	32,100	32,400	32,700	33,000	33,300	33,600	33,900	34,200	34,500

Table 2: Representative Net Installed Capacity Requirements

Year	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	**2030**
NET ICR (MW)[2]	34,500	34,800	35,100	35,400	35,700	36,000	36,300	36,600	36,900	37,200	37,600	37,900	38,200

Demand Resources

- Establish three separate Demand Resource scenarios to bracket the probable range of regional penetration
  - **Low Demand Resources Case (5%)**
    - Passive Demand Resources: On peak and Seasonal Peak (EE) – 1,725 MW[3] by 2030
    - Active Demand Resources: Real-Time Demand Response – 1,650 MW[4] by 2030

[1] The 2018 50/50 peak of 30,960 MW increased at 0.9% per year and rounded to the nearest 100 MW.
[2] Net ICR calculated assuming 111.3% of the 50/50 peak load and rounded to the nearest 100 MW. Net ICR reflects the amount of generating and demand resources to be procured in the Forward Capacity Market (FCM) (based on total tie benefits of 1,665 MW and excluding Hydro-Québec Interconnection Capability Credit (HQICC)).
[3] Assumed to be 5% of gross peak with Transmission & Distribution (T&D) gross-up in rating. (34,500 MW x 0.05 =1,725 MW)

    - Real-Time Emergency Generation – 800 MW every year

- **Medium Demand Resources Case (10%)**
    - Passive Demand Resources: On peak and Seasonal Peak (EE) – 3,450 MW[5] by 2030
    - Active Demand Resources: Real-Time Demand Response – 3,100 MW[6] by 2030
    - Real-Time Emergency Generation – 800 MW every year
- **High Demand Resources Case (15%)**
    - Passive Demand Resources: On peak and Seasonal Peak (EE) – 5,175 MW[7] by 2030
    - Active Demand Resources: Real-Time Demand Response – 4,400 MW[8] by 2030
    - Real-Time Emergency Generation – 800 MW every year

Table 3: 2030 Net Peak Load Calculations

	Low Demand Resources (5%)	**Medium Demand Resources (10%)**	**High Demand Resources (15%)**
2030 Original Peak (Gross MW)	34,500	34,500	34,500
Passive Demand Resources (MW)	1,725	3,450	5,175
Active Demand Resources (MW)	1,650	3,100	4,400
Emergency Generation (MW)	800	800	800
2030 Net Peak for Existing Electricity Generating Technologies (MW)	30,325	27,150	24,125

[4] Real time DR assumed to be 5% of net peak with T&D gross-up in rating (34,500 MW – 1,725 MW = 32,775 MW x .05 = 1,650 MW).
[5] Assumed to be 10% of gross peak with T&D gross-up in rating. (34,500 MW x .10 =3,450 MW)
[6] Real-time DR assumed to be 10% of net peak with T&D gross-up in rating (34,500 MW – 3,450 MW = 31,050 MW x .1 = 3,100 MW).
[7] Assumed to be 15% of gross peak with T&D gross-up in rating. (34,500 MW x .15 =5,175 MW)
[8] Real-time DR assumed to be 15% of net peak with T&D gross-up in rating (34,500 MW – 5,175, MW = 29,325 MW x .15 = 4,400 MW).

Plug-in Electric Vehicles

- Establish three separate PHEV scenarios based on a range of potential penetration
  - **Low PHEV Case**: 0.833 million vehicles in New England by 2030 (assume 1/3 of High PHEV Case)
  - **Medium PHEV Case**: 1.666 million vehicles in New England by 2030 (assume 2/3 of High PHEV Case)
  - **High PHEV Case**: 2.5 million vehicles in New England by 2030 based on Oakridge National Lab projections[9]

Table 4: PHEV Analysis for 2030 Assuming 2.0 kW Power Connector

	Low PHEV (33%)	Medium PHEV (66%)	High PHEV (100%)
Penetration (Million PHEV)	0.833	1.666	2.500
Max Off-Peak charging (MW)	1,679	3,358	5,037
On-Peak Delivery to the Grid (MW)	0	0	0
Annual Charging Energy (GWh)	2,293	4,586	6,880
Energy Delivery to the Grid (GWh)	0	0	0
New England Annual Energy (Gross GWh)	162,256	162,256	162,256
Percent of New England Energy Requirements (%)	1.4	2.8	4.2

Maine Proposal to Convert Oil Heat to Electric Heat

Maine's Ocean Energy Task Force, recognizing the state's potential for utilizing offshore wind power to make electricity, is discussing the possibility of minimizing the state's use of oil for home heating by advancing electric heat as an alternative. "There appears to be room for improvement..." according to the

[9] Please see attached EXCEL Spreadsheet (Attachment 4).

State of Maine Comprehensive Energy Plan 2008-2009, which states that “80% of residences and business use oil for heating, which is highest per capita in the nation.”

- Maine Public Utility Commission (PUC) suggested assumptions are provided in Attachment 3.

Capacity Resources

Existing Installed Capacity (reflects 2012/13 Capability Year - FCM Qualified Resources)

- Generation – 31,400 MW
  - Intermittent – 1,100 MW (small wind and small hydro resources)
- Purchases – 1,100 MW (cleared Forward Capacity Auction #2 (FCA2))
- Demand Resources:[10]
  - On-peak and Seasonal Peak (EE) – 650 MW
  - Real-Time Demand Response – 1,100 MW
  - Real-Time Emergency Generation – 800 MW

New Resource Alternatives

Resource Additions

- Generation – Wind
  - Establish four separate wind penetration scenarios to bracket the probable range of regional wind penetration. Use a 12,000 MW (nameplate) case as the high end and tie in with ISO’s on-going wind integration study, which is studying approximately 7,500 MW of onshore wind and 4,500 MW of offshore wind.[11] (See Attachment 2)
  - The initial three cases will be set at 2,000 MW, 4,000 MW, and 8,000 MW (nameplate), split evenly between onshore and offshore projects.
  - Offshore wind will be split evenly 1/3 each for Maine, Massachusetts and Rhode Island for all four cases.
  - For the initial three cases, the onshore wind will be adjusted to be consistent with the state-by-state percentages in the 12,000 MW case.

[10] Includes 8% T&D Loss Gross-up.
[11] Additional cases could be conducted to evaluate wind penetration beyond the 12,000 MW threshold.

Table 5: 12,000 MW Wind Case[12]

State	On shore (MW) 7,500	Off shore (MW) 4,500
Connecticut	0	0
Maine	4,500	1,500
Massachusetts	1,000	1,500
New Hampshire	1,200	0
Rhode Island	150	1,500
Vermont	650	0

Table 6: 8,000 MW Wind Case

State	On shore (MW) 4,000	Off shore (MW) 4,000
Connecticut	0	0
Maine	2,500	1,330
Massachusetts	500	1,330
New Hampshire	600	0
Rhode Island	60	1,330
Vermont	350	0

[12] Please see Attachment 2 for detailed development of the wind assumptions

Table 7: 4,000 MW Wind Case

State	On shore (MW) 2,000	Off shore (MW) 2,000
Connecticut	0	0
Maine	1,250	665
Massachusetts	250	665
New Hampshire	300	0
Rhode Island	30	665
Vermont	175	0

Table 8: 2,000 MW Wind Case

State	On shore (MW) 1,000	Off shore (MW) 1,000
Connecticut	0	0
Maine	625	330
Massachusetts	125	330
New Hampshire	150	0
Rhode Island	20	330
Vermont	90	0

- Generation – Natural Gas
  - As an alternate base case, substitute 1,500 MW of natural gas combined cycle units for 4,000 MW of wind to approximate the energy output of wind in the base case.

- Energy Storage
    - Establish several generic scenarios to bracket the probable range of new energy storage technologies. This could be developed based on high, medium, and low scenarios, or more simply with and without the energy storage. The technologies could include new pumped storage hydro, batteries, compressed air, or other technologies.

Table 9: Energy Storage Sensitivities

	Low Storage	**Medium Storage**	**High Storage**	**Giant Storage**
Storage Size (MW)	1,000	2,000	3,000	5,000
Storage Capability	Daily	Daily	Daily	Daily
Round Trip Efficiency (%)	85	85	85	85
Weekly Storage	No	No	No	No
Reduces ICR (Replaces Existing Generating Resources)	No	No	No	No

Figure 1: Effect of Demand Resources on Hourly Loads for Peak Week

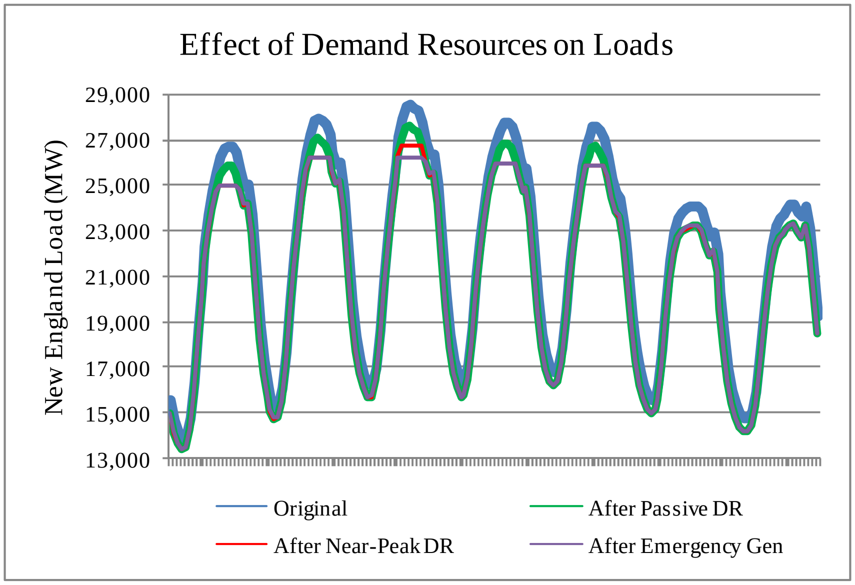
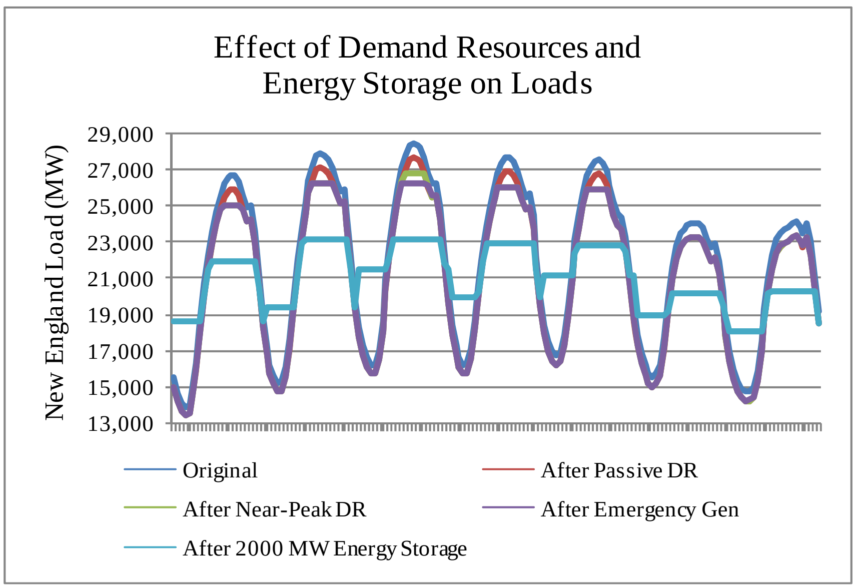


Figure 2: Effect of Demand Resources and Energy Storage on Hourly Loads for Peak Week



- Resource retirements and possible repowering
  - Establish three separate approaches to modeling existing coal and oil unit retirements
    - Assume retirement of all units > **70** years old as of 2030
    - Assume retirement of all units > **60** years old as of 2030
    - Assume retirement of all units > **50** years old as of 2030
  - Establish multiple re-powering scenarios to correspond with each combination of events being modeled. Assume natural gas combined cycle/natural gas peaking resources are located at the existing sites as needed to satisfy the projected ICR requirements.

Table 10: Age Ranges of Coal and Residual Fuel Oil (RFO) Steam Generators in 2030

Age Range of Units (Years)	MW
>=40 and <50	181
>=50 and <55	1,156
>=55 and <60	3,107
>=60 and <65	1,880
>=65 and <70	1,250
>=70 and < 75	927
>=75	290
Total	8,791

Table 11: Threshold Years for Coal and RFO Steam Generators in 2030

Age Threshold of Units (Years)	MW
>=40	8,791
>=50	8,610
>=55	7,454
>=60	4,347
>=65	2,467
>=70	1,217
>=75	290

Table 12: Power plants likely to fall into calculations for resource attritions

Generator	Capacity (MW)	Fuel Type	In-service Date(s)[13]
Brayton Point Station	1,100 440	coal oil	1963-69 1974
Bridgeport Harbor 3	370	coal	1968
Canal 1&2	1,100	oil	1968-76
Merrimack Station	430	coal	1960-68
Mount Tom	145	coal	1960
Mystic 7	565	oil	1975
Middletown Station	765	oil	1958-73
Montville Station	490	oil	1954-71
New Haven Harbor Station	450	oil	1975
Newington Station (PSNH)	400	oil	1974
Norwalk Harbor Station	330	oil	1960-63
Salem Harbor Station	310 430	coal oil	1952-58 1972
Schiller 4&6	95	coal	1952-57
Somerset 6	110	coal	1959
West Springfield 3	107	oil	1957
Wyman (Yarmouth) Station	820	oil	1958-78

[13] Based on ISO's *Capacity Energy Loads and Transmission (CELT)* report

- Establish scenarios to look at the impact of expanded interconnections with our neighbors:
    - No change
    - New 1,500 MW tie with New Brunswick
    - New 1,500 MW tie with Quebec
    - Increased capability across New York/New England interface
    - 9,600 MW interconnection into Norwalk per Joint Coordinated System Plan (JCSP)
    - Combinations of the above
    - Assumptions will have to be made on the nature of the energy across the interface to define the impact on costs, emissions, etc. as shown in Attachment 1, proposed cases 22 through 27.

Attachment 1 – Initial list of cases to be evaluated

	Case	Description
1	Base	One Year 2030 Only; All resources in with no retirements; • All resources in with no retirements • Passive Demand Resources (EE) of 3,450 MW • Active Demand Resources of 3,100 MW • Real Time Emergency Generation of 800 MW • Assume medium PHEV penetration of 2/3 of Oak Ridge's 2.5 million estimate with a 2 kW power interface connector • Medium Maine conversion from oil to electric heat • Wind Penetration of 4,000 MW (2,000 onshore; 2,000 offshore)
1a	Base – Natural Gas	Same as Base Case except add 1,500 MW of new efficient natural gas combined cycle (CC) units in place of 4,000 MW of wind to emulate the energy from wind in the Base Case
2	Retire 70	Same as Base Case except 1,000 MW of units older than 70 years old will be retired and replaced with an equal amount of new efficient gas combined cycle (CC) (1,217 MW)
3	Retire 60	Same as Base Case except 4,000 MW of units older than 60 years old will be retired and replaced with an equal amount of new efficient gas CC (4,347 MW)
4	Retire 50	Same as Base Case except ~9,000 MW of units older than 50 years old will be retired and replaced with an equal amount of new efficient Gas CC (8,610 MW)
5	Repower 70	Same as Base Case except 1,000 MW of units older than 70 years old will be retired and replaced with a re-powering that is natural gas fueled and is less efficient than a new gas CC (1,217 MW)
6	Repower 60	Same as Base Case except 4,000 MW of units older than 60 years old will be retired and replaced with a re-powering that is natural gas fueled and is less efficient than a new gas CC (4,347 MW)
7	Repower 50	Same as Base Case except ~9,000 MW of units older than 50 years old will be retired and replaced with a re-powering that is natural gas fueled and is less efficient than a new gas CC (8,610 MW)
8	High DR	Same as the Base case except higher DR • Passive DR (EE) of 5,175 MW • Active DR of 4,400 MW • Real Time EG of 800 MW
9	Low DR	Same as the Base case except higher DR • Passive DR (EE) of 1,725 MW • Active DR of 1,650 MW • Real Time EG of 800 MW
10	High PHEV	Same as the Base case except using 100% of Oak Ridge's PHEV penetration estimate of 2.5 Million by 2030
11	Low PHEV	Same as the Base case except using 1/3 of Oak Ridge's PHEV penetration Oak Ridge's 2.5 Million
12	Higher Electric Heat	Same as the Base case except higher Maine conversion from oil to electric heat
13	Lower Electric Heat	Same as the Base case except lower Maine conversion from oil to electric heat
14	2,000 Wind	Same as the Base case except wind penetration of 2,000 MW (1,000 onshore; 1,000 offshore)
15	8,000 Wind	Same as the Base case except wind penetration of 8,000 MW (4,000 onshore; 4,000 offshore)
16	12,000 Wind	Same as the Base case except wind penetration of 12,000 MW (8,000 onshore; 4,000 offshore)
17	Giant Storage	Same as the Base case except 5,000 MW of new storage with daily energy discharge / recharge (20 percent of 2.5 million PHEV at 10 kW each able to peak shift).
18	High Storage	Same as the Base case except 3,000 MW of new storage with daily energy discharge / recharge

	Case	Description
19	Medium Storage	Same as the Base case except 2,000 MW of new storage with daily energy discharge / recharge
20	Low Storage	Same as the Base case except 1,000 MW of new storage with daily energy discharge / recharge
21	Biomass	Convert units over 70 years old to burn Biomass, based on unit size constraints
22	1,500 NB Wind	Same as the Base case except 1,500 MW of wind in NB
23	1,500 HQ Hydro Profile Delivery	Same as the Base case except 1,500 MW of additional Hydro based imports (modeled like current HQ economic imports)
24	1,500 HQ Base Load Profile Delivery	Same as the Base case except 1,500 MW of HQ interconnection would be 100% capacity factor hydro (from Labrador?)
25	1,500 HQ Wind Profile Delivery	Same as the Base case except 1,500 MW of additional Wind profile imports
26	1,000 MW NY Wind Profile Delivery	Import 1,500 MW of Wind from New York due to increased interconnections with New York
27	JCSP Wind	Inject 9,600 MW of wind / coal into Norwalk (decide an amount of coal and wind percentages for Regional Greenhouse Gas Initiative (RGGI) type emission leakage accounting)

Attachment 2 – New England 2030 Power System Study, Wind Assumptions

For wind power development in New England, in theory, the “low hanging fruit” will be developed first. This means that probable sites for wind development will proceed with the best onshore locations first. The term “best” would have to include:

- Highest annual mean wind speed
- Exclusion from urban and natural resource areas
- Areas that are lower in elevation
    - reduces blade icing problems
    - reduces installation costs
    - reduces impact on viewshed
- Areas where the ground slope is manageable
    - reduces installation costs
    - reduces wear and tear on turbines due to high vertical inflow
- Areas where there is a large concentration of developable sites
- Areas nearest existing transmission
- For offshore development
    - shallow water—reduces cost of installation
    - outside of the three nautical mile limit—facilitates permitting

It is somewhat difficult to predict the ranking of importance of the above criteria. However, applying screens based on the above criteria to the Levitan & Associates, Inc. (LAI) Phase II Available Onshore Locations results (slide 29) essentially eliminates all class 7 and class 6 onshore sites as can be seen below in Figure 1.

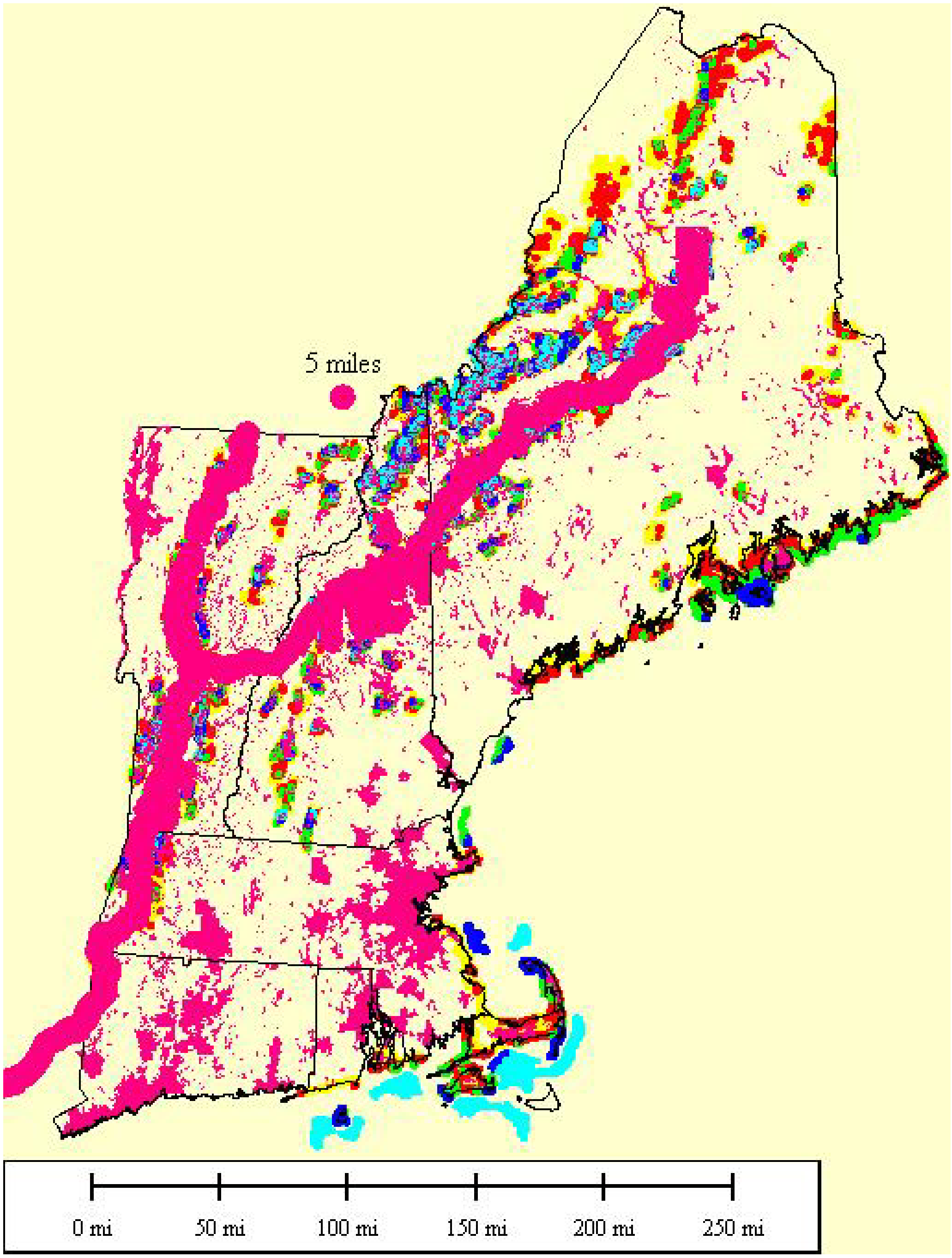


Figure 1: Wind Sites in New England, Screening Applied

In Figure 1, the pink color that overlays much of New England (and essentially all of the onshore class 6 (dark blue) and class 7 (aqua) wind sites) indicates regions that will most probably not be developed for reasons of high elevation, high slope, and/or proximity to protected or urban areas. A five-mile buffer zone around the Appalachian Trail and Long Trail are clearly visible as long pink trails connecting in central Vermont that together form the shape of the letter "y".

Excluding the class 6 and class 7 onshore wind sites, decreases the overall available onshore Installed Capacity (ICAP) from 47,124 MW to 42,171 MW. Raising the criteria for economic viability from class 3 wind speeds to class 4 wind speeds reduces the overall available onshore ICAP from 42,171 MW to 15,399 MW. Table 2 shows the results of these screens, Table 1 is reproduced from the LAI Phase II study results presentation for convenience.

Table 13: LAI Phase II Onshore ICAP

Region	**Total**	Class 7	Class 6	Class 5	Class 4	Class 3
CT	**35**	0	0	1	3	31
ME	**26904**	925	1,547	2,969	5,807	15,656
MA	**6585**	25	177	440	1349	4594
NEMA	**300**	0	0	0	8	292
SEMA	**5154**	0	130	362	1,136	3,526
WCMA	**1131**	25	47	78	205	776
NH	**6125**	597	706	847	1,358	2,617
RI	**653**	0	22	100	100	431
VT	**6822**	286	668	872	1,553	3,443
Total	**47124**	**1833**	**3120**	**5229**	**10170**	**26772**

Table 2: Post Screening Onshore ICAP Totals

Region	**Total**	Class 7	Class 6	Class 5	Class 4	Class 3
CT	**4**	0	0	1	3	0
ME	**8776**	0	0	2,969	5,807	0
MA	**1789**	0	0	440	1349	0
NEMA	**8**	0	0	0	8	0
SEMA	**1498**	0	0	362	1,136	0
WCMA	**283**	0	0	78	205	0
NH	**2205**	0	0	847	1,358	0
RI	**200**	0	0	100	100	0
VT	**2425**	0	0	872	1,553	0
Total	**15399**	**0**	**0**	**5229**	**10170**	**0**

LAI Phase II does not break down the offshore ICAP results by state, so an estimate of the results has been made based on the ratio of the areas shown in LAI Phase II slide 50. Table 3 (below) gives the results of this breakdown.

Table 3: Breakdown of Offshore Wind by State

Region	**Total**	Class 7	Class 6	Class 5
CT	**0**	0	0	0
ME	**550**	300	100	150
MA	**6250**	5198	902	150
NH	**50**	0	0	50
RI	**2440**	2440	0	0
VT	**0**	0	0	0
Total	**9290**	**7938**	**1002**	**350**

When a more stringent water depth screen is applied (30m instead of 60m), essentially all of the New Hampshire offshore windpower sites are eliminated. While most of the offshore windpower sites in Maine are also eliminated, the one large class 7 site is not eliminated: there is a lack of information regarding water depth. Some of the sites in Massachusetts and a small portion of the sites in Rhode Island are also eliminated. Figure 2 shows graphically the results of the water depth screen—as before in Figure 1, pink indicates areas where (due to water depth) offshore windfarms will not be built.

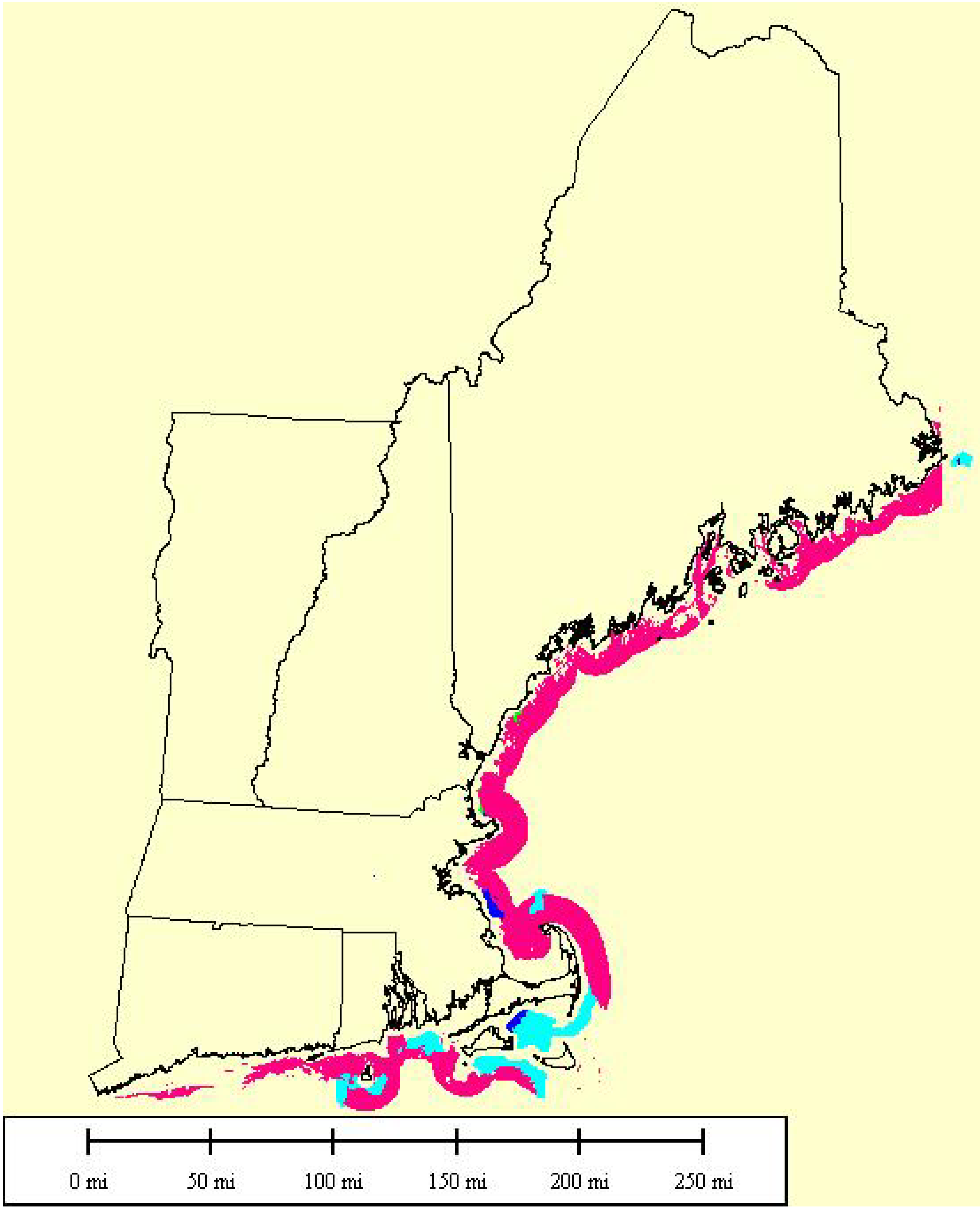


Figure 2: Offshore Wind Sites in New England, 30m max Water Depth

Table 4 shows the numerical results of the more stringent water depth criterion.

Table 4: Offshore Wind Sites Breakdown by State, 30m max Water Depth

Region	**Total**	Class 7	Class 6	Class 5
CT	**0**	0	0	0
ME	**300**	300	0	0
MA	**4800**	4198	602	0
NH	**0**	0	0	0
RI	**2040**	2040	0	0
VT	**0**	0	0	0
Total	**7140**	**6538**	**602**	**0**

Due to the extra cost of installation and difficulty in operation and maintenance of offshore windpower, it is reasonable to presume that onshore windpower sites will be developed first. Local and state initiatives promoting onshore and offshore windpower development will dictate the pace and final overall amounts of installed windpower. Table 5 summarizes the numerical results given in Tables 1 and 4: an overall total of 22.5 GW is obtained by summing the onshore and offshore results.

Table 5: New England Windpower ICAP after Additional Screens

	Onshore (MW)					Offshore (MW)	
Region	**Total**	Class 5	Class 4		**Total**	Class 7	Class 6
CT	**4**	1	3		**0**	0	0
ME	**8776**	2,969	5,807		**300**	300	0
MA	**1789**	440	1349		**4800**	4198	602
NH	**2205**	847	1,358		**0**	0	0
RI	**200**	100	100		**2040**	2040	0
VT	**2425**	872	1,553		**0**	0	0
Total	**15399**	**5229**	**10170**		**7140**	**6538**	**602**

If the assumption is made that 20% of the electrical energy consumed in New England in 2030 will come from New England based windpower, a rough approximation can be made that 12 GW of installed windpower will be required. Table 6 shows the results of simply scaling the results in Table 5 by a constant ratio of 12 GW divided by 22.5 GW.

Table 6: New England Windpower ICAP after Simple Proportioning for 12 GW Total

	Onshore (MW)					Offshore (MW)	
Region	**Total**	Class 5	Class 4		**Total**	Class 7	Class 6
CT	**2**	1	2		**0**	0	0
ME	**4672**	1581	3092		**160**	160	0
MA	**952**	234	718		**2556**	2235	321
NH	**1174**	451	723		**0**	0	0
RI	**106**	53	53		**1086**	1086	0
VT	**1291**	464	827		**0**	0	0
Total	**8197**	**2784**	**5415**		**3802**	**3481**	**321**

Given the wide range of project support or opposition, which varies from state to state, Table 6 can be adjusted to a final table (Table 7) for recommendations for onshore and offshore windpower development assumptions for the ISO-NE footprint for the year 2030.

Table 7: New England Windpower ICAP Final Recommendations for Assumptions for 12 GW Wind

Region	**Total Onshore (MW)**	**Total Offshore (MW)**
CT	**2**	**0**
ME	**4672**	**160**
MA	**952**	**2556**
NH	**1174**	**0**
RI	**106**	**2000**
VT	**650**	**0**
Total	**7556**	**4716**

Attachment 3 – Maine Oil Heat Conversions

Assumptions Regarding Penetrations of Electric Space Heating in Maine:

- Heat pump space heating uses half as much electricity to heat the home as resistance heating and produces space heat at the equivalent of about $1.15 per gallon of oil heat when electricity is priced at $.15/kWh and $.86/ gallon at $.12/kWh[14]. Assume half of all new electric space heat is geothermal.
- kW demand = 6.3 kW for space, water heat customers[15]
- Half a million households in Maine
- Current electric heat penetration is 4%
- CMP space heat 1993 = 6.8% primary, 12.2% secondary/supplemental[16]
- Assume installed baseboard electric has been left in place[17]

Baseline of Homes that Could Increase Use Immediately

1. MW demand if homes who could switch back to primary space heating responded to a promotional rate. (.068 - .04)*500,000*6.3/1000 = 88.2
2. MW demand if supplemental heat customers satisfy 25% of their heating needs with electricity in response to a promotional rate. .122*500,000*.25*6.3/1000 = 384.3
3. Total = 88 + 384 = 472 MW

Low Conversion Rate Maine Achieves MA Penetration

1. MW demand if homes who could switch back to primary space heating responded to a promotional rate. (.068 - .04)*500,000*6.3/1000 = 88.2
2. MW demand if supplemental heat customers satisfy 25% of their heating needs with electricity in response to a promotional rate. .122*500,000*.25*6.3/1000 = 384.3
3. Maine achieves MA penetration of 12% primary electric space heat.
    a. Resistance ((.12 - .04)/2)*500,000*6.3/1000) = 126
    b. GT ((.12 - .04)/2)*500,000*3.15/1000) = 63
    c. (.12 - .04)*500,000*6.3/1000 = 252
4. Total = 88 + 384 + 126 + 63 = 661 MW

Medium Conversion Rate Maine Achieves CT penetration

1. MW demand if homes who could switch back to primary space heating responded to a promotional rate. (.068 - .04)*500,000*6.3/1000 = 88.2

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[14] G. Hart Ocean Energy Institute
[15] July 1983 CMP Research Dept. "Impact of Wood Heat on Electric Energy Consumption" 95% of electric space heat customers also heat water electrically.
[16] CMP Maine Power Reliability Program (MPRP) Filing ODR-01-68
[17] Anecdotal information from home energy auditors

2. MW demand if supplemental heat customers satisfy 25% of their heating needs with electricity in response to a promotional rate. .122*500,000*.25*6.3/1000 = 384.3
3. Maine achieves CT penetration of 15% primary electric space heat.
    a. Resistance ((.15 - .04)/2)*500,000*6.3/1000) = 173
    b. GT ((.15 - .04)/2)*500,000*3.15/1000) = 87
4. Total = 88 + 384 + 173 + 87 = 732 MW

Highest Conversion Rate Maine Achieves US Average Penetration

1. Maine achieves US average penetration of 30% primary electric space heat.
    a. Resistance ((.30 - .04)/2)*500,000*6.3/1000) = 410
    b. GT ((.30 - .04)/2)*500,000*3.15/1000) = 205
2. Total = 88 + 384 + 410 +205 = 1,087 MW

Attachment 4 – Assumed PHEV Penetration by Year 2030 based on Oakridge National Lab Projections

Table A4-1: Maximum MW Impact of Electric Plug In Hybrid Vehicles

Maximum MW Impact of Electric Plug In Hybrid Based on Three Charging Rates and GWh Annual Energy Impact
Based on "Potential Impacts of Plug-in Hybrid Vehicles on Regional Power Generagtion"
Jan 2008, Oak Ridge National Laboratory, ORNL/TM-2007/150

	Max MW at 1.4kw	Max MW at 2.0kw	Max MW at 6.0kw	Annual GWh	New Vehicles	EPHV Share	Cumulative EPHV	RSP09 Energy
2011	25	34	69	47	692936	0.025	17323	132350
2012	73	102	207	140	689066	0.050	51777	134015
2013	146	204	413	279	686090	0.075	103233	134635
2014	243	339	686	463	682260	0.100	171459	136085
2015	363	506	1025	692	679122	0.125	256350	137540
2016	507	706	1430	965	674912	0.150	357586	139025
2017	674	938	1900	1282	671567	0.175	475111	140565
2018	863	1203	2435	1643	668421	0.200	608795	142125
2019	1075	1498	3034	2047	665601	0.225	758555	143703
2020	1310	1826	3697	2494	662656	0.250	924219	145298
2021	1540	2147	4347	2933	650000	0.250	1086719	146910
2022	1770	2468	4997	3371	650000	0.250	1249219	148541
2023	2000	2790	5647	3810	650000	0.250	1411719	150190
2024	2231	3111	6297	4249	650000	0.250	1574219	151857
2025	2461	3432	6947	4687	650000	0.250	1736719	153543
2026	2691	3753	7597	5126	650000	0.250	1899219	155247
2027	2921	4074	8247	5564	650000	0.250	2061719	156970
2028	3152	4395	8897	6003	650000	0.250	2224219	158713
2029	3382	4716	9547	6441	650000	0.250	2386719	160474
2030	3612	5037	10197	6880	650000	0.250	2549219	162256

Figure A4-1: Maximum MW Impact of Electric Plug In Hybrid Vehicles

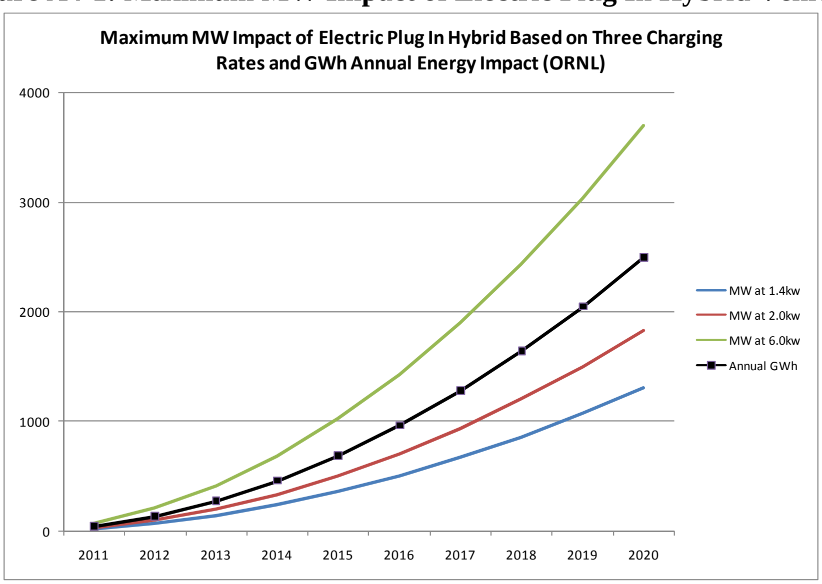

Table A4-2: 2012 to 2030 MW Impacts Over 9 Charging Hours at 1.4 kW

Hour	2012	2014	2016	2018	2020	2030	Ratio
1:00 AM	37	122	253	432	655	1806	0.500
2:00 AM	73	243	507	863	1310	3612	1.000
3:00 AM	73	243	507	863	1310	3612	1.000
4:00 AM	73	243	507	863	1310	3612	1.000
5:00 AM	68	226	471	801	1217	3356	0.929
6:00 AM	42	139	290	493	749	2065	0.572
7:00 AM	26	87	181	308	468	1290	0.357
8:00 AM	16	52	109	185	281	775	0.215
9:00 AM	5	17	36	62	94	259	0.072

Figure A4-2: 2012 to 2030 MW Impacts Over 9 Charging Hours at 1.4 kW

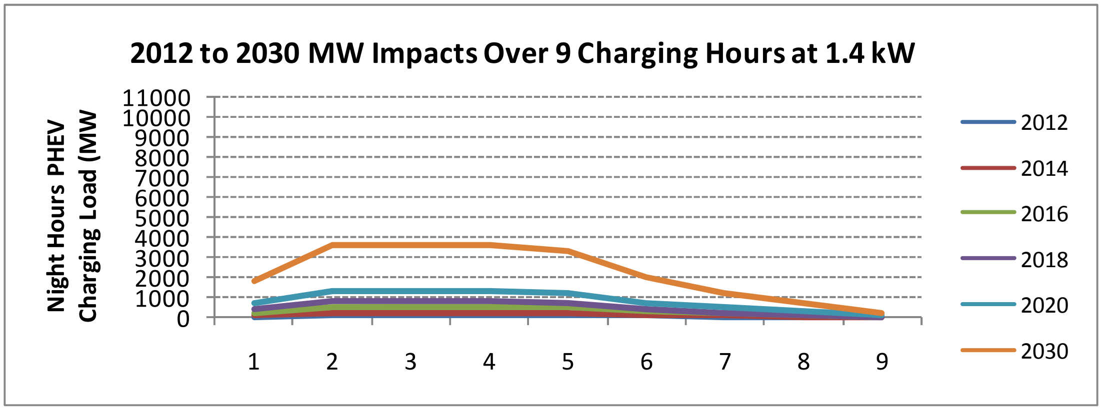

Table A4-3: 2012 to 2030 MW Impacts Over 7 Charging Hours at 2.0 kW

Hour	2012	2014	2016	2018	2020	2030	Ratio
1:00 AM	51	169	353	601	913	2519	0.500
2:00 AM	102	339	706	1203	1826	5037	1.000
3:00 AM	102	339	706	1203	1826	5037	1.000
4:00 AM	77	254	530	902	1369	3776	0.750
5:00 AM	51	169	353	601	913	2519	0.500
6:00 AM	26	85	177	301	456	1258	0.250
7:00 AM	5	17	35	60	91	251	0.050

Figure A4-3: 2012 to 2030 MW Impacts Over 7 Charging Hours at 2.0 kW

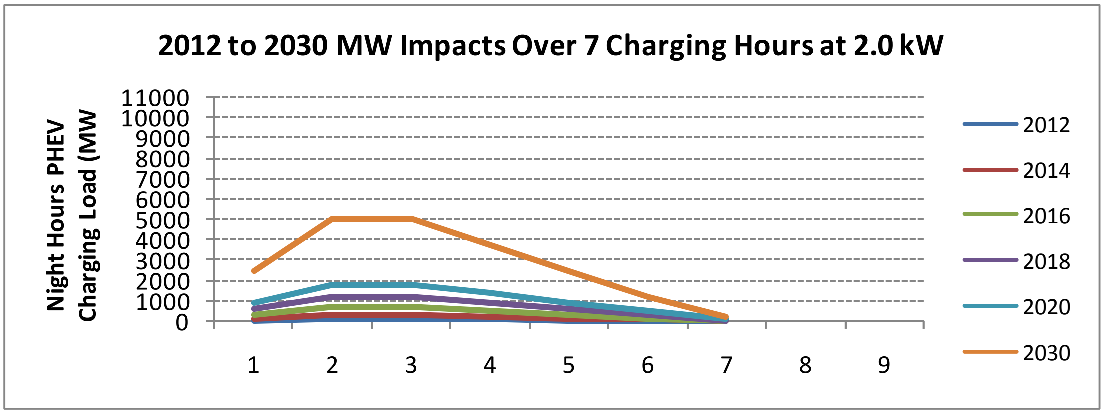

Table A4-4: 2012 to 2030 MW Impacts Over 3 Charging Hours at 6.0 kW

Hour	2012	2014	2016	2018	2020	2030	Ratio
1:00 AM	155	514	1073	1826	2773	7648	0.750
2:00 AM	207	686	1430	2435	3697	10197	1.000
3:00 AM	52	171	358	609	924	2549	0.250

Figure A4-4: 2012 to 2030 MW Impacts Over 3 Charging Hours at 6.0 kW

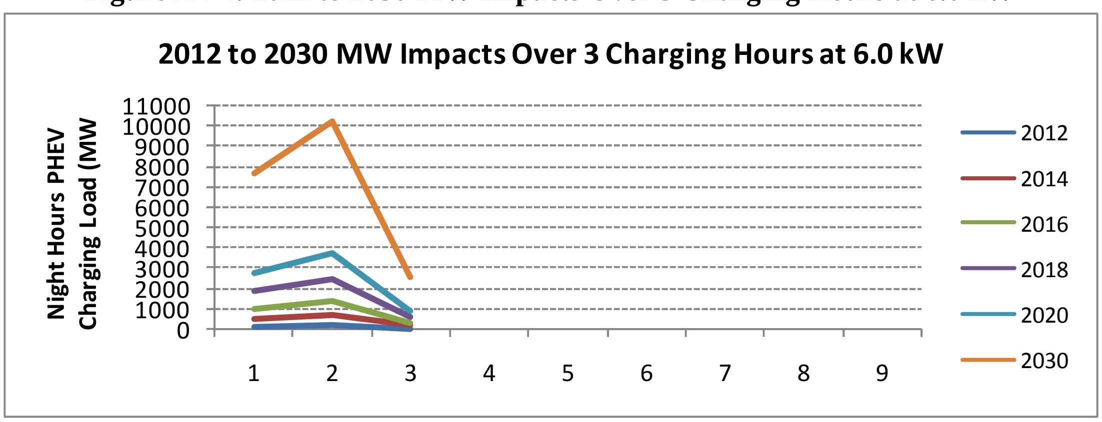

Table A4-5: 2030 PHEV Charging Impacts Over 7 Charging Hours at 2.0 kW

Hour	100% of 2.5 Million	2 / 3 of 2.5 Million	1 / 3 of 2.5 Million
1:00 AM	2519	1679	840
2:00 AM	5037	3358	1679
3:00 AM	5037	3358	1679
4:00 AM	3776	2518	1259
5:00 AM	2519	1679	840
6:00 AM	1258	839	419
7:00 AM	251	167	84

Figure A4-5: 2030 PHEV Charging Impacts Over 7 Charging Hours at 2.0 kW