Technical and Economic Limits for Renewable Power Integration in New England

Full Report

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Reiner W. Kuhr

Energy Technology Economist

Ahmad Nofal

Energy Analyst

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Abstract:

Adding wind, solar and energy storage facilities on a large scale to replace gas combined cycle plants encounters major technical and economic limits.

Doubling existing solar and wind generation plus rapid expansion of offshore wind by 2030 will require over $60 billion in new investments, will increase annual subsidies from $1 to over $5 billion, and will reduce carbon dioxide emissions by about 30%. Substantial additional investment and subsidies will be required for associated transmission and distribution improvements. Consumers who already pay the highest rates in the continental US will encounter large rate increases with negative regional economic impacts.

Most of the region's CO2 emissions are produced by gas power plants that provide grid control and reliability. Carbon abatement costs ($/ton CO2 avoided) are calculated by comparing unsubsidized costs for wind and solar with gas generation, and then dividing by the amount of CO2 avoided. Solar and wind generation will cost 2-15 times the current federal policy guideline of $51/ton as the estimated economic impact of carbon dioxide emissions. The uncertain environmental value of reducing CO2 emissions may be less than the economic damage from higher energy costs and market disruptions.

While most CO2 is produced in the evenings, solar generation occurs mid-day, and wind generation occurs intermittently. New solar and wind generation will increasingly occur at the wrong times, resulting in wasted surpluses (curtailments) and lost opportunity to reduce CO2 emissions. Some surplus generation from solar and wind will be driven into the competitive market by large operating subsidies, offering negative pricing and undermining the value of plants that need to operate during those periods. About 20% of solar and wind generation will be wasted in 2030.

Battery storage must operate in 24-hour cycles, limiting the opportunity to reduce surpluses that vary unevenly. Low utilization makes battery storage prohibitively expensive and ineffective in reducing CO2 emissions.

Subsidies for solar and wind generation will increase to over three times the market value of electricity in 2030, socializing most of the cost of regional power generation. State regulatory actions to mandate investment in solar, battery and offshore wind projects by distribution companies constitute partial re-regulation of the power industry in New England.

The authors intend to share evaluation tools and modeling approaches through a new platform for on-line collaboration between universities and other organizations.

1. Executive Summary

Over $60 billion in investments are proposed to expand solar and wind generation in New England and reduce emissions of carbon dioxide. Technical and economic limits will severely restrict the effectiveness of these investments. Understanding how these technologies operate in the power grid and their economic relationships in reducing emissions are the key to evaluating these limits. Excessive solar and wind power generation is likely to seriously damage both the regional power grid and economy as subsidies drive surplus energy into a competitive market.

Technical limits are addressed in this report by modeling the timing and interaction of power generation in the regional grid. New solar and wind generation becomes progressively ineffective and disruptive by producing heavily subsidized electricity at the wrong times. Wind and solar generation do not occur uniformly, limiting the ability of battery storage operating in 24-hour cycles to recover surpluses. Reducing the utilization and remaining life of gas power generation undermines the future flexibility and reliability of our power grid. Increasing power grid loads to support electrification of building and transportation contradicts efforts to reduce reliance on gas generation.

Understanding economic limits requires new metrics to clarify the balance between the cost of reducing carbon emissions and the damage to the economy from higher taxation and rapidly rising energy costs. Estimating carbon abatement costs for solar and wind technologies provides an indication of the relative effectiveness of investments to reduce carbon emissions.

Establishing a Social Cost of Carbon (SCC) is highly controversial but sets an important policy determination of the value of reducing emissions. SCC sets a point beyond which expenditures on decarbonization are judged to be more harmful to the economy than they are beneficial to the environment. The profound economic impact of rising energy prices and the effect of subsidies pushing surplus energy into a competitive regional wholesale market are important consequences that deserve further study and public review to inform this relationship.

The only federal policy guidance on SCC is currently set by the Biden administration at $51/ton CO2. This value is an attempt to monetize the environmental damage from one ton of CO2 produced by human activity. This policy guidance is highly controversial and likely to change with future administrations. The determination of SCC, as well as analysis of the negative economic impact of spending more than the SCC guideline, should be subject to considerable analysis and public debate given the magnitude of proposed investments.

Comparing the estimates for carbon abatement cost presented in this report reveals an alarming relationship. Investments in grid connected solar and wind power generation cost two to six times the current SCC policy guideline. Investments in behind the meter (BTM) distributed solar installations exceed SCC by a factor of fifteen. The cost of using battery storage to lower carbon emissions by reducing wasted surpluses is about 7-19 times the current SCC guideline. These results assume efficient subsidies and exclude the cost of associated grid improvements. Carbon abatement costs increase further as the utilization of solar and wind generators become reduced by the inability to use all their output.

Climate legislation requires an assessment of cost-effectiveness in pursuing pathways to Net Zero carbon emissions. The relationship between costs and benefits drives many important questions:

- How much are we spending and how are we paying to reduce carbon emissions?
- What are the resulting benefits and key uncertainties?
- Should there be a limit to how much we spend to reduce carbon emissions?
- Should we prioritize expenditures by avoiding those that are least effective?
- When do we see the declining effect of integrating batteries, solar and wind generation?
- Do we understand the impacts of pushing heavily subsidized surplus energy into competitive markets?
- Are we rapidly approaching a point of diminishing returns where additional renewable generation is progressively ineffective and disruptive with costs exceeding benefits?
- Are we effectively re-regulating power generation through state environmental regulation and socializing most of the costs of producing electricity?

These major questions and others are addressed in the work presented in this report.

Section 1.1 summarizes current grid characteristics and plans for expanding solar and wind generation, including projected costs and carbon emission reductions.

Section 1.2 defines key technical limits including the need for flexibility and reliability, transmission constraints, the mismatch in timing between CO2 emissions and solar and wind generation, and the inability of battery storage to effectively reduce surpluses.

Section 1.3 summarizes economic limits in terms of higher costs, required subsidies, relative carbon abatement costs, and wasted surpluses.

Section 1.4 addresses the question of policy guidance by selecting a Social Cost of Carbon (SCC) that sets a limit on how much should be spent to reduce carbon emissions.

Section 1.5 summarizes how surpluses and negative pricing can damage the economics of much of the region’s power generation.

Section 1.6 summarizes key policy questions that need public discussion regarding the impact of technical and economic limits on consumers and on the future power grid.

This report presents the results of a three-year academic effort to model and evaluate the relationships between energy technology, economics, and policy. Modeling approaches have been developed and applied to the calculation of carbon abatement costs and to hourly analysis of grid loads, dispatch, pricing and emissions. Extensive efforts to collect, evaluate and prepare data have been supported by networking and collaboration with several individuals and organizations representing a wide range of knowledge and experience. The authors intend to share modeling approaches and supporting information through a new platform for online collaboration between universities and other interested parties. Several multi-university initiatives will be pursued for follow-up evaluations and reports through the newly established Center for Academic Collaboration (CACI - *www.centeraci.com*).

1.1. Expanding Renewable Power Generation to Reduce Carbon Emissions

The New England power grid is a modern, efficient, low-emitting, and reliable system benefiting from access to low-cost natural gas and three operating nuclear units. Many other power grids around the world rely heavily on the use of oil and coal for much of their power generation and pay much more for natural gas. Most of the recent reduction in regional CO2 emissions is due to the economic shift to burning inexpensive natural gas, virtually eliminating the need to operate oil or coal fired plants except during extreme events. Further reductions in regional CO2 emissions are much more difficult and expensive to achieve because gas power generation is inexpensive and supports grid flexibility and reliability.

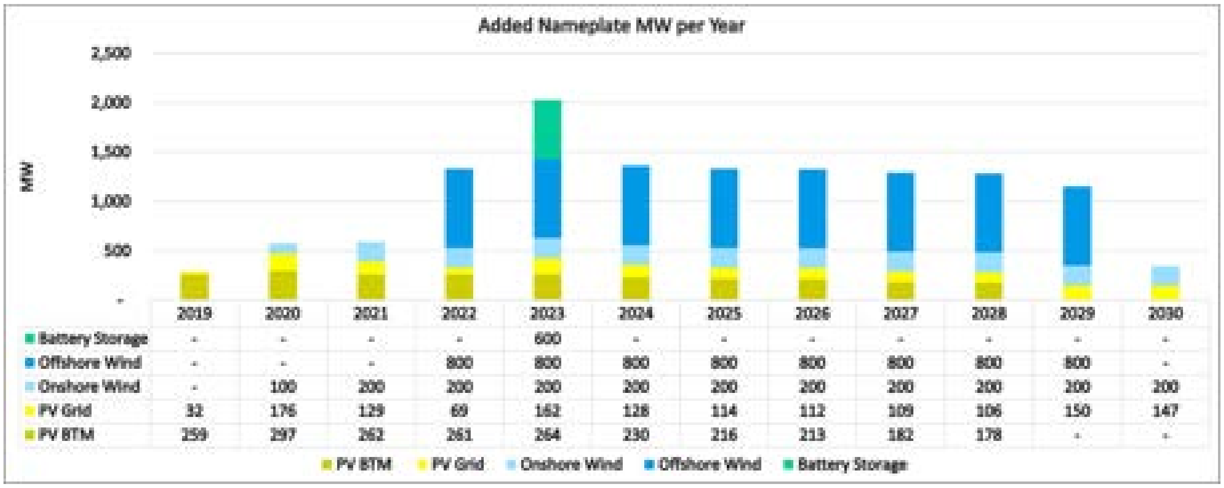
Total system load typically varies from about 10 GW during in early morning hour to peaks ranging seasonally from about 15-25 GW in the evenings. A fleet of about 16 GW of gas combined cycle plants operate to close the gap between hourly loads and other available generation. Most of the electric power CO2 emissions in New England are produced by these gas combined cycle plants that offer attractive production costs varying with the cost of gas. Some of their operation will be displaced with new, more expensive solar and wind generation. Consumers that already pay more for electricity than most of the US will pay for the higher costs through taxes and increasing electric rates.

About 33 million tons per year of CO2 are currently emitted from power generation in the region including 26 from gas combined cycles with the remaining 9 from burning wood, municipal solid waste, and landfill gas. Achieving “Net Zero” would mean reducing this rate to about 2.5 million tons per year in 2050.

New England has invested over $11 billion mostly over the last decade to install about 5,300 MW of wind and solar generation. This investment currently requires over $1 billion per year in rate and tax subsidies and avoids about 4.2 million tons per year of CO2 emissions by reducing the operation of gas combined cycle plants. The Pilgrim Nuclear Station retired in 2019 primarily for economic reasons causing carbon dioxide emissions to increase by 2.8 million tons per year.

Current New England state policies target a doubling of existing solar and onshore wind power generation from about 8.7 TWh (terawatt-hours, or 1000s MWh) in 2021 to 16.6 TWh in 2030, plus explosive growth of new offshore wind farms (14.6 TWh in 2030) based on new capacity shown in Figure 1.

Figure 1 New England Capacity Added per Year



PV BTM = behind the meter PV; PV Grid = grid-connected PV

This represents an investment of over $61 billion for about 11 GW (1000s MW) of new wind and solar installations by 2030. New photovoltaic and wind generating plants are subsidized primarily through state project mandates, tax credits, net metering and state clean energy credits. 800 MW per year of new offshore wind represents an investment of $50 billion between 2022 and 2029. Other investments represent roughly a doubling of existing solar and onshore wind generation and the addition of 600 MW of BES (battery energy storage systems). Additional BES installations are being considered. Investments in distributed PV generation are assumed to stop after 2028 due to increasing surpluses and poor economics.

As shown in Figure 2 below, this $61 billion investment will reduce CO2 emissions from 33 to below 21 million tons per year by 2030. Investments each year have declining effectiveness reducing CO2 emissions.

Figure 2 Cumulative Investments in Renewables vs Annual CO2 Emissions

Reductions in CO2 emissions level off near 21 million tons/year after 2027 as more solar and wind generation occurring during low load periods is wasted (curtailed) each year and as electrification of buildings and transportation require additional generation from gas plants.

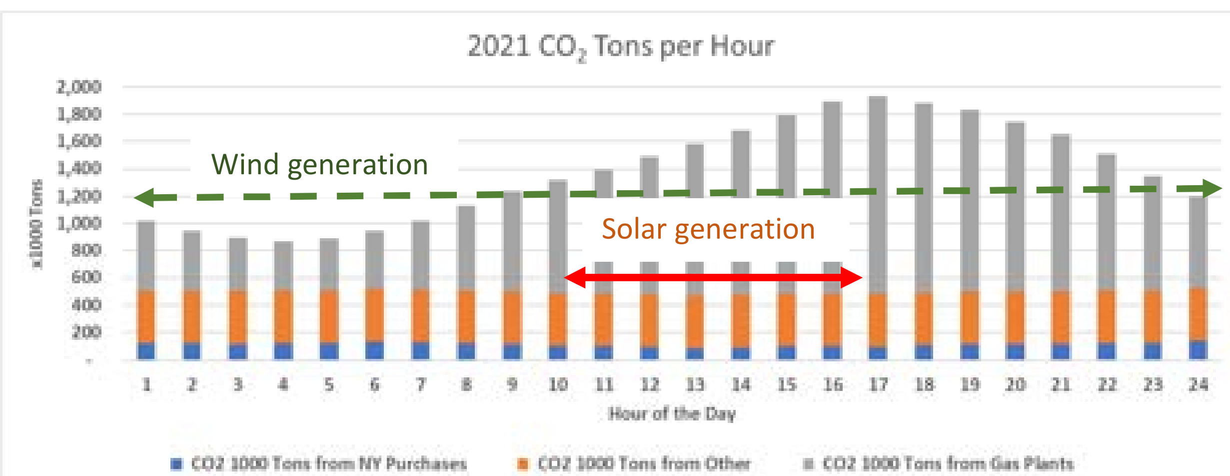
The declining effectiveness of investments and subsidies in achieving further reductions in CO2 emissions is due to the inefficient interaction of new solar and wind plants with loads, and with other generation and regional power purchases.

1.2. Technical Limits

Replacing gas combined cycle generation with renewable energy encounters several technical limitations. Gas combined cycle plants provide grid flexibility and control. Wind and solar generation are inflexible and often occur at the wrong times relative to electric loads as illustrated in Figure 3.

- Existing fossil generation capacity will continue to be needed for peak loads since extended periods with no solar or wind resources can occur.
- Some gas combined cycle generation is needed at all times, even during surpluses, to provide system control and flexibility. More wind and solar installations will result in faster changes between loads and generation. This can be partially mitigated by new inverter technology and new battery energy storage (BES) plants. CO2 emissions from gas plants increase with more frequent starts and load changes.
- CO2 emissions occur mostly in the evenings, while solar generation occurs midday and wind generation is spread intermittently (less than half the time). This limits the opportunity for solar and wind generation to reduce CO2 emissions.
- Using BES to provide generation during peak periods increases CO2 emissions unless charging is restricted to surplus wind and solar generation.

Figure 3 Annual CO2 Production by Hour



Most CO_2 production occurs in the evenings after solar generation declines and when wind is only available intermittently.

Other technical limits include lower regional solar resources, land use conflicts, natural gas pipeline capacity, supply chain problems, and current transmission capabilities.

- New England investment in solar power generation is less effective than in other regions which have better solar resources. Moving a PV installation in New England to the Southwest US would obtain 1.5 – 2 times the output.
- Expansion of onshore wind generation is limited to sites further from load centers with increasing transmission connection and integration costs. There is growing public opposition to the use of large parcels of land for wind and solar farms, which has encouraged the development of offshore wind.
- Natural gas supply to the New England power grid is inadequate during winter months when gas use shifts to building heating. This causes increased use of oil to replace gas in power plants, and the use of older, higher emitting oil and coal plants during peak winter loads. However, this occurs infrequently and has little impact on CO_2 emissions. Electrification of buildings and transportation will amplify the problems of limited winter gas supply. Balancing increasing variable wind generation during these periods will cause higher CO_2 emissions by causing more inefficient operation of gas generation
- Expansion of offshore wind generation may be limited by supply chain constraints, including the availability of special offshore construction equipment.
- The configuration of the current transmission system limits the opportunity to connect large new generation projects without huge investments. Some early offshore wind projects may connect to transmission connections formerly used by retired coal and nuclear plants, but subsequent connections become more expensive.

Adding wind and solar generation increases the amount of unusable surplus generation that result in curtailments when plants that otherwise must run are not allowed to. This effect is illustrated by comparing annual total generation by hour for 2030 as shown in Figure 4 below, assuming offshore wind is curtailed first. Curtailments occur mostly in the mornings when loads are low and when there is excessive wind generation. Adding more wind generation capacity increases curtailments early in the day, while adding solar generation capacity increases curtailments mid-day. By 2030, almost 20% of solar and wind generation is unusable because of this timing mismatch.

Figure 4 2030 Annual Solar and Wind Generation and Curtailments by Hour

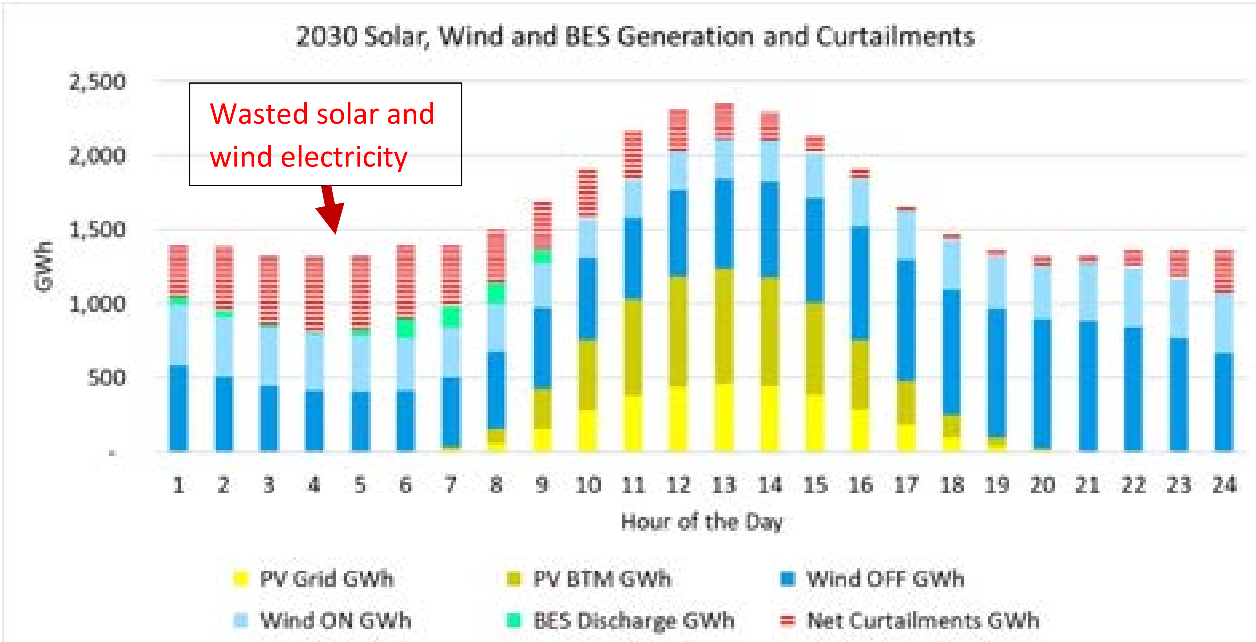
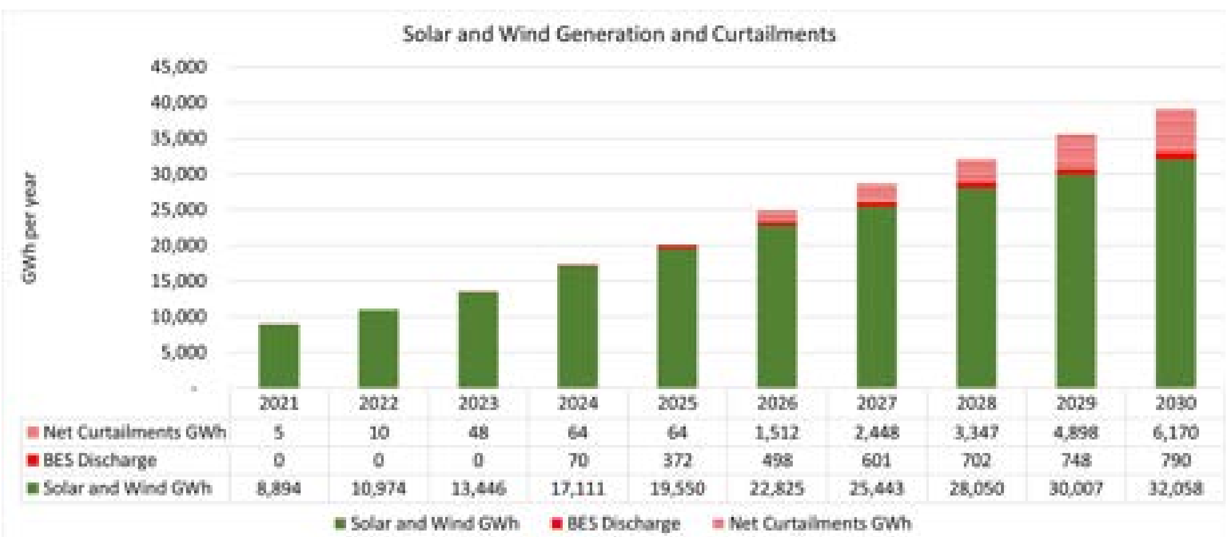


Figure 5 below shows how wasted wind and solar energy increases after 2024. A small portion of this wasted generation is recovered by 600 MW of BES installed in 2024.

Figure 5 Increased curtailments relative to new generation

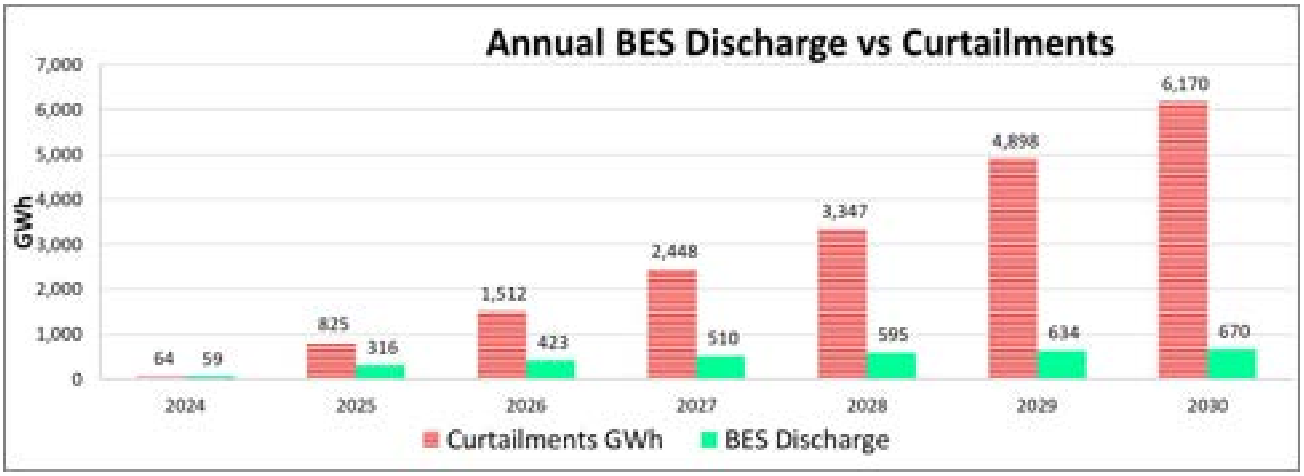


Increasing curtailments reduce the ability of new wind and solar generators to reduce CO2 emissions and reduce their income from market sales and from subsidies when they don't operate.

The role of BES to recover wasted energy from curtailments and to further reduce CO2 emissions is limited by the timing of loads and generation within 24-hour operating cycles.

- Charging BES when incremental generation is from gas combined cycle plants increases CO_2 emissions, since BES only returns about 85% of energy used for charging.
- BES operation can reduce CO_2 emissions only when charging with surplus energy from wind and solar, and when discharging to displace gas generation.
- 600 MW of BES installed in 2024 has limited utilization for CO_2 reduction until the amount of surplus wind and solar energy increases. Adding more BES would reduce its average utilization. As shown below in Figure 6, 600 MW of BES has very little impact on reducing wasted surpluses because it can only discharge 4 hours per day (16.67% of the year), and surpluses occur roughly 40% of the year by 2030.

Figure 6 600 MW Battery Storage Discharge vs Curtailments



1.3. Economic Limits

Economic limits associated with the addition of solar and wind generation to reduce CO_2 emissions should consider the higher cost of power from renewables, carbon abatement costs, the effects of increasing subsidies, and the cost of wasted energy.

Power production costs

Power production costs are estimated for existing and new power generation facilities based on published US EIA estimates adapted to the New England region.

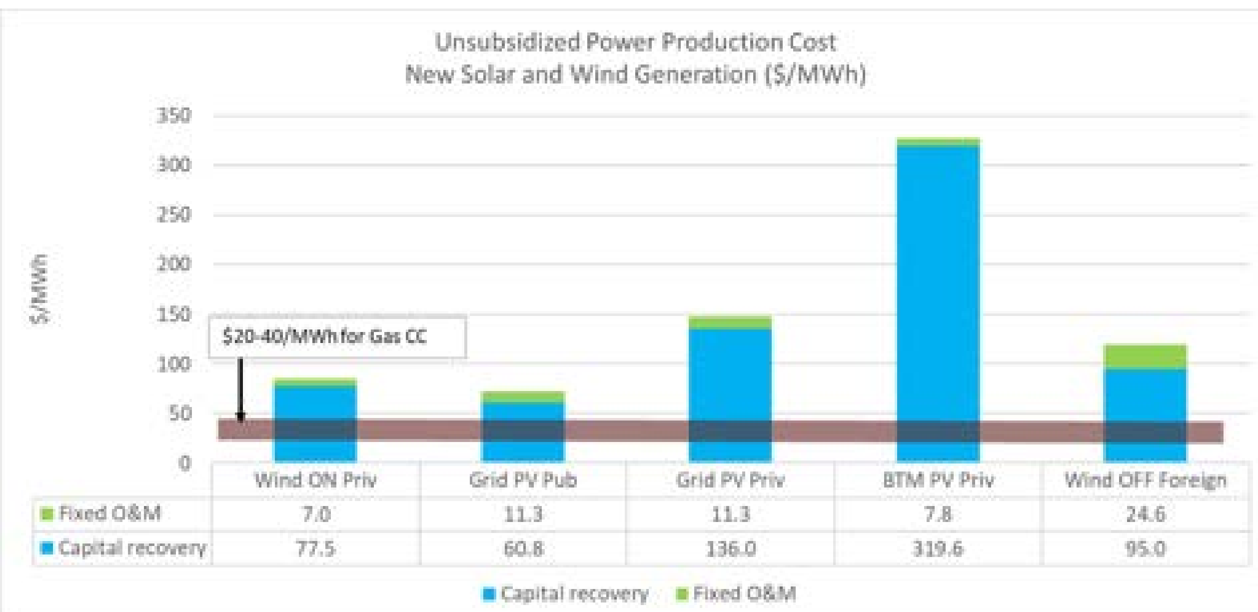
- The fuel and operating costs of generating electricity from existing gas combined cycle plants range from about $20-40/MWh depending on the price of natural gas ($2.5-5/MMBTU) and variations in power plant conversion efficiency. Although market conditions will change gas pricing from time to time, the long-term availability of inexpensive and plentiful gas production in the U.S. should support this range.
- The estimated cost for continuing to operate existing nuclear generating stations in New England is about $30-40/MWh, depending on what level of investment will be required for improvements and nuclear regulatory compliance associated with life extension.

- The cost for producing electricity from solar and wind plants is primarily driven by recovering capital per MWh produced. Cost of capital varies with ownership, lowest for public power or export financed projects and highest with private financing.

The costs of power production for new solar and wind installations are summarized in Figure 7 below. These costs represent the total expenditures required to build a new plant and are referred to as “unsubsidized” since they exclude the effect of tax benefits (accelerated depreciation, investment tax credits, performance tax credits), clean energy credits, net metering, or above-market payments through power purchase agreements.

Costs for major components of PV, wind and battery systems have declined substantially as a result of improved technology, mass production, and relocation of manufacturing plants to other countries with lower cost labor, material and less environmental regulation. Future reductions in these costs are uncertain given shortages of key materials, limited opportunity for further scale increases, and proposed policy initiatives to shift production back to the US. Also, installation costs may increase as more difficult sites are developed and grid integration becomes more difficult.

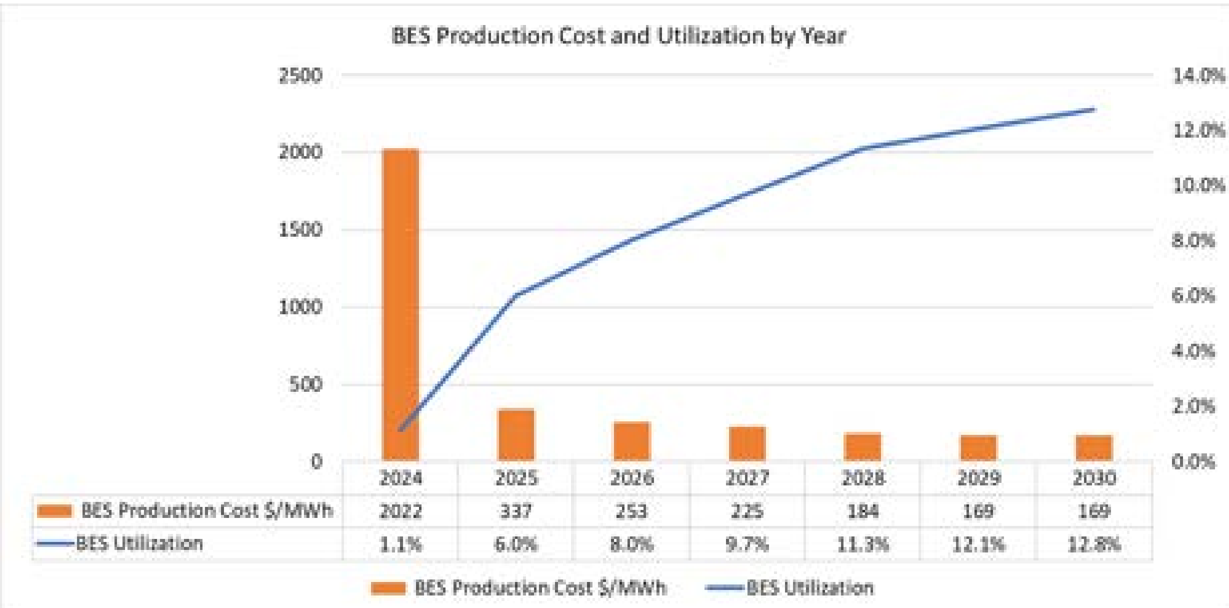
Figure 7 Power production cost for new wind and solar generation



Based on EIA assumptions adjusted for New England, 2020 dollars, “Pub” = public ownership, “Priv” = private ownership, Gas CC = gas combined cycle plants

The production cost for battery storage on a $/MWh basis is very sensitive to how much energy is discharged in a year. Most of the production cost of BES is capital recovery which increases per MWh with lower utilization. 600 MW of 4-hour battery storage begins operations in 2024 and has a maximum possible annual utilization of 16.67% if discharged daily. Curtailments increase as more wind and solar are installed as shown in Figure 6. Restricting the use of BES to reduce CO2 emissions reduces its utilization depending on how often curtailments occur in each 24-hour cycle. As shown in Figure 8 below, the production cost of using BES to reduce CO2 emissions is very high in 2024 when curtailments are low, and decreases as curtailments increase allowing more utilization. Even with high curtailments in 2030, BES utilization approaches 13% lowering output costs to $169/MWh. This excludes the cost or credit for charging energy.

Figure 8 Production Cost for Battery Storage



Adding more BES after 2024 would reduce utilization increasing BES production cost. These estimates assume that BES systems are operated only to reduce CO2 emissions. Economic benefits of utilizing BES to provide capacity and flexibility are similar to those provided by gas combined cycle plants that are displaced and not considered in estimating production costs for this analysis.

Subsidies

Subsidies for each technology are estimated as the difference between the unsubsidized cost of new plants and the avoided cost of generation for gas combined cycle plants shown in Figure 7.

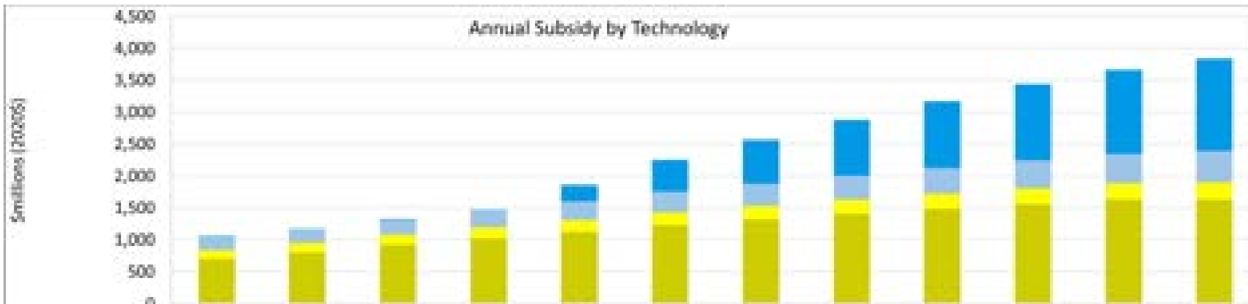
- Power production costs range from about $72-137/MWh for new grid connected solar and wind, to $328/MWh for behind the meter (BTM) solar.
- The subsidies required for each technology are calculated as the difference between their total cost and the $20-40/MWh for operating existing gas combined cycle plants.
- Federal tax credits and accelerated depreciation can cover about a third of wind and solar project costs.
- Clean energy credits vary by state and are sized to cover remaining project costs and profitability. They are adjusted annually to support increases in solar and wind

generation as required by rising resource portfolio standard targets and changing market conditions.

- State mandated projects require electric distribution companies to build BES and PV plants which become part of their rate base (assigned to all ratepayers), or to contract directly for electricity from offshore wind projects at higher-than-market prices passed along in rates.
- The cost of subsidies for natural gas production is less than \$.10/MMBtu and well within the accuracy and range of gas price variability.

Projected subsidies for wind and solar generation are shown by year in Figure 9 below in 2020 dollars based on a long-term natural gas price of \$3/MMBtu.

Figure 9 Projected Annual Subsidies by Technology



	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Wind Off Subsidy	9	9	9	9	253	497	687	875	1,040	1,196	1,314	1,442
Wind On Subsidy	213	215	230	262	293	325	349	377	405	440	462	492
Grid Solar Subsidy	141	145	163	177	185	202	214	225	236	249	257	273
BTM Solar Subsidy	701	803	920	1,022	1,125	1,228	1,318	1,403	1,486	1,558	1,628	1,628

The substantial costs of transmission and distribution improvements needed to support these solar and wind installations are difficult to determine and are not included in these estimates. Subsidies for BTM solar are disproportionately high.

As shown below in Figure 10, total subsidies increase from about \$1.1B/year in 2019 to \$3.9B/year in 2030 assuming an average subsidy of \$200/MWh. During this period market revenue (the sum of hourly generation times hourly price) declines from \$3.9B/year to \$2.1B/year. The annual cost of wasted surplus solar and wind energy grows to \$1.4B in 2030.

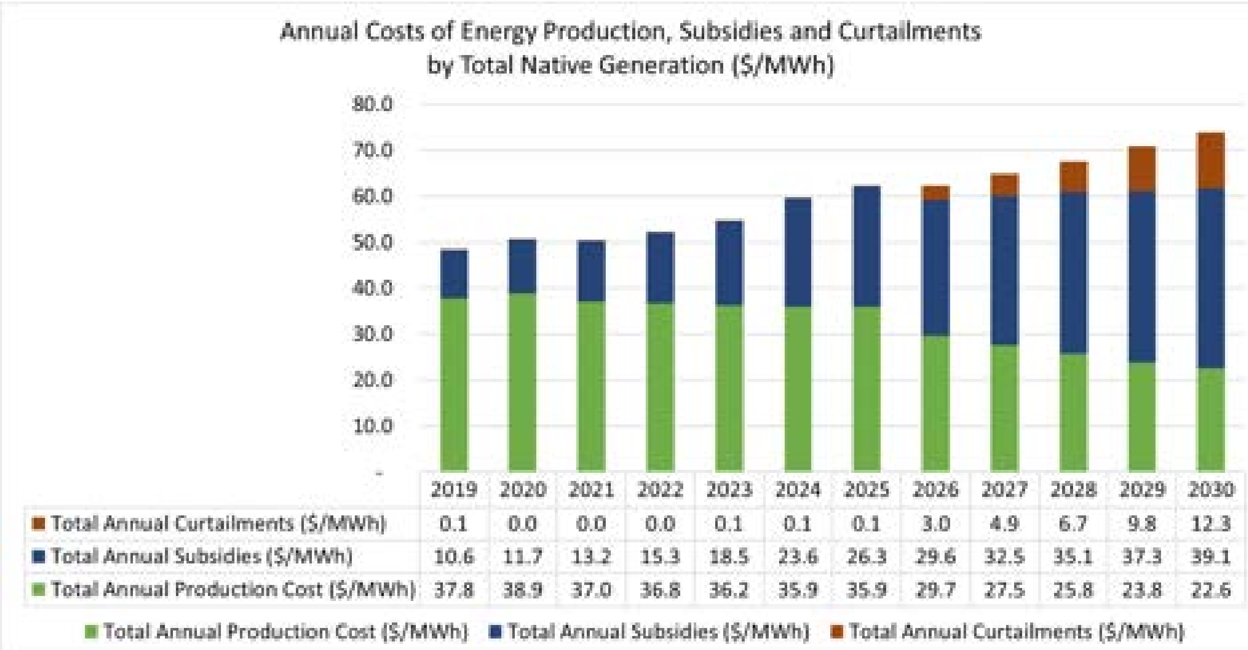
Figure 10 Changes in Market Revenue vs Subsidies

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Value of Curtailments $M	7	0	1	2	10	13	13	302	490	669	980	1,234
Total Subsidies $M	1,064	1,172	1,322	1,534	1,855	2,370	2,638	2,971	3,263	3,529	3,745	3,924
Total Market Revenue $M	3,795	3,904	3,720	3,694	3,637	3,610	3,610	2,984	2,766	2,590	2,390	2,268

This shift in magnitude from market revenue to subsidies changes the emphasis of project planning and asset management to respond to state policies rather than to grid needs. Increasing electric rates will reflect the combined effect of rising long term subsidy commitments and lower wholesale rates resulting from periods of negative pricing. Subsidies will vary with gas prices and other factors. About 7.5 million electric customers and taxpayers in the region will pay for these market revenue, subsidies, and curtailment losses.

Figure 11 below shows the cost per MWh of subsidies and curtailments relative the total market value of generation by year. This shows that by 2030, consumers will be paying for more than two thirds of their electricity through taxes and additional charges in their electric bill. Additional charges will reflect the impact of growing long-term commitments associated with mandated projects, renewable energy credits, net metering, and offtake agreements. These values exclude additional costs for transmission and distribution improvements, and for capacity and flexibility (ancillary services) costs passed along to ratepayers. Declining market value (total annual production costs) results from the growing impacts of negative pricing during curtailments which can vary widely from these estimates.

Figure 11 Subsidies, Curtailments and Market Value per MWh

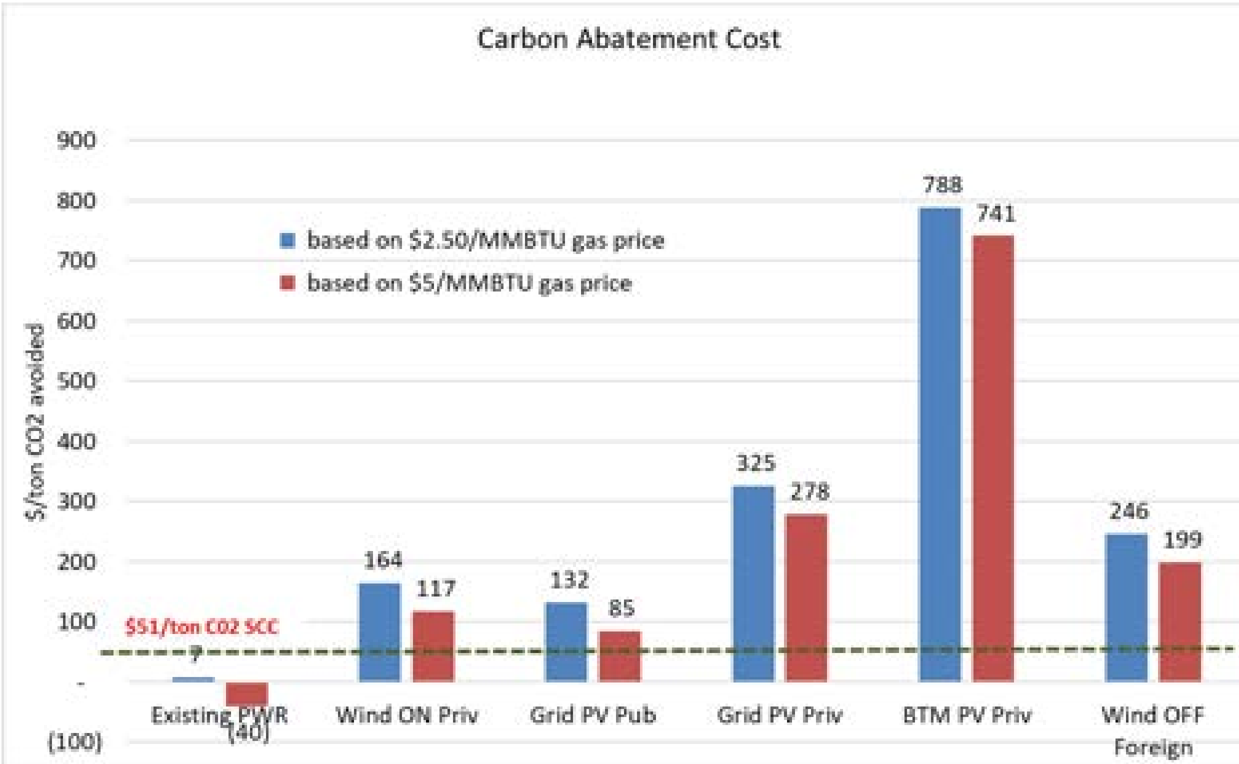


	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Total Annual Curtailments ($/MWh)	0.1	0.0	0.0	0.0	0.1	0.1	0.1	3.0	4.9	6.7	9.8	12.3
Total Annual Subsidies ($/MWh)	10.6	11.7	13.2	15.3	18.5	23.6	26.3	29.6	32.5	35.1	37.3	39.1
Total Annual Production Cost ($/MWh)	37.8	38.9	37.0	36.8	36.2	35.9	35.9	29.7	27.5	25.8	23.8	22.6

Carbon Abatement Costs

Pollution abatement cost, the cost of reducing a ton of emissions, has long been used by the Environmental Protection Agency and others to evaluate suitable environmental mitigation measures. Carbon abatement cost is calculated by comparing the costs of proposed non-emitting power production with the cost of operating existing gas combined cycle plants, then dividing the extra cost by the amount of CO2 avoided. Hourly modeling of grid behavior determines how much each type of generation operates, and how much CO2 is avoided. A range of gas prices is considered. Solar and wind installations displace fuel and variable costs from gas combined cycle plants, which continue to operate to provide grid flexibility and reliability.

Figure 12 Carbon Abatement Costs

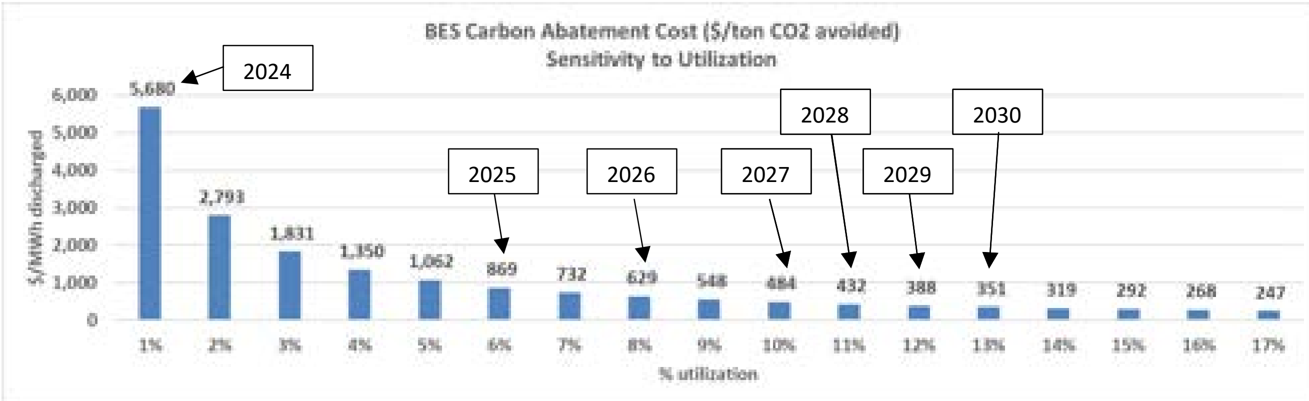


Existing PWR = operating nuclear plants; Wind ON = onshore wind; Wind OFF=offshore wind; Priv=private financing; Pub=public financing; Foreign refers to international ownership with possible export financing.

As seen in Figure 12 above, only extending the life of the existing nuclear units has favorable economics relative to a policy based Social Cost of Carbon (SCC) of $51/ton announced by the Biden administration.

The chart below in Figure 13 shows the carbon abatement cost of using battery storage to recover surplus wind and solar energy. Consistent with Figure 8, carbon abatement costs are sensitive to utilization based on the need to recover capital and fixed operating costs. Operating 600 MW of battery storage to reduce CO2 emissions in the New England system has a limited impact and is very expensive with carbon abatement costs over $350/ton. Adding more battery storage would reduce utilization for reducing emissions and increase carbon abatement costs.

Figure 13 Carbon Abatement Cost for Battery Storage



Based on 2020 dollars; BES cost does not include the cost of charging energy

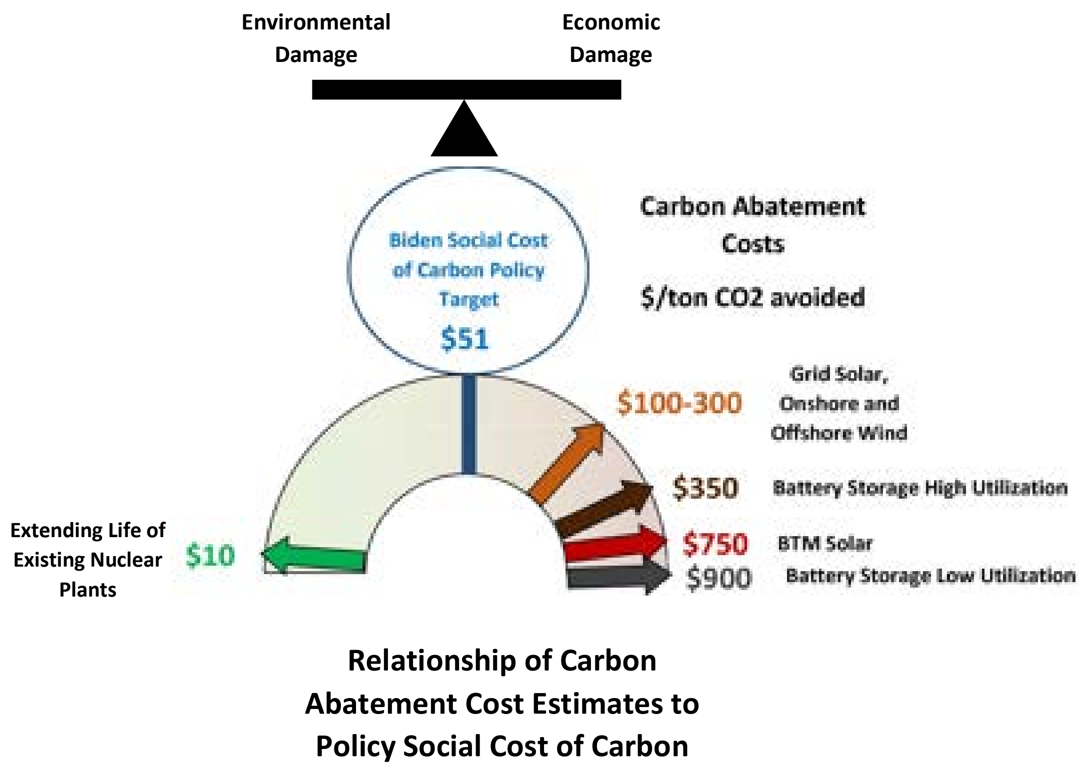
1.4. Social Cost of Carbon

Evaluating the cost effectiveness of policy options should consider the value of avoiding carbon dioxide emissions. The cost of not reducing CO2 emissions has been evaluated by the US General Accounting Office based on the present value of estimated costs of damage driven by human caused changes in climate. This "Social Cost of Carbon" (SCC) has been presented as a basis for energy policy by the Biden administration, currently set at $51/ton CO2. This announcement is highly controversial and is subject to legal challenges.

SCC is important to represent the maximum level of carbon abatement cost justified by the benefits of carbon reduction. Also, SCC represents an equivalent carbon tax, which could be applied universally in place of other subsidies. Establishing SCC is much more difficult and controversial than estimating carbon abatement costs. It represents a policy judgement. Exceeding SCC can be interpreted as wasteful spending which causes more economic harm than environmental benefit.

The chart below in Figure 14 highlights the relationship of carbon abatement cost to current policy guidance on the Social Cost of Carbon. Note that grid connected wind and solar installations cost 2-15 times the current policy SCC, and battery storage cost 7-18 times SCC. As SCC is defined, spending more than SCC to reduce carbon emissions exceeds environmental benefits and is unnecessarily harmful to the economy.

Figure 14 Relationship of Carbon Abatement Costs to Policy Target



None of the wind and solar technologies being installed would be justified based on a $51/ton policy criterion. The determination and application of SCC as the basis for energy policy has been challenged based on major uncertainties in applying climate science and modeling, and the limited effectiveness of reducing regional emissions without global support.

The process of considering SCC as a basis for New England energy policy becomes increasingly important as the scale of proposed investments and subsequent market disruptions increase.

1.5. Market Impact of Surplus Generation

During periods of curtailment, subsidized plants can bid negative energy pricing into the wholesale power market to share subsidies with the market rather than losing them by not operating. This causes competitive wholesale prices to become negative during curtailments, forcing operating plants to pay to run. The projected occurrence of negative pricing in 2030 is shown in Figure 15, an indicative price duration curve, assigning some nominal variable costs for wind and solar generators, and applying a $10/MWh uniform regional clean energy credit that triggers negative pricing. Current subsidies are much higher and would support more severe negative pricing.

Figure 15 Example of Negative Pricing

This chart shows estimated wholesale price sorted from highest to lowest by hour in 2030. Key points include:

- Highest prices occur during peak periods, during loss of key generators or transmission, and when the region experiences gas shortages in the winter.
- When there are no curtailments, prices are normally set by gas combined cycle plants with higher winter fuel costs.
- Pricing is negative during curtailments in 2030 for about 40% of the year.
- Negative pricing severely reduces annual income to nuclear power plants, solar and wind generation, municipal solid waste units, and hydroelectric plants reducing asset values and shortening economic lives by discouraging major repairs and life extension.
- Negative pricing will shift asset management decisions in response to state subsidies rather than to long term market needs.
- Flexible gas fired units needed to balance changing loads during surpluses will also have to pay to run, requiring other revenue or additional subsidies.

1.6. Key policy questions

Results of this analysis drive key questions for policy makers and for the public.

1. Do the potential benefits of carbon emission reductions justify the high cost of adding wind and solar power generation, plus the additional costs of transmission and distribution improvements? By 2030, based on total annual native (New England based) generation of about 98,000 GWh:
    a. Estimated subsidies will increase from $11 to 38/MWh. Actual electric rates will reflect allocation of costs unevenly through state regulation and different customer groups.
    b. Cost of curtailments will approach $14/MWh.
    c. Average wholesale energy prices drop from $38/MWh to $21/MWh due to negative pricing assuming no change in gas prices.

d. Cost of transmission and distribution improvements needed for new solar and wind installations will increase substantially and should be examined.
e. Long term selective support for solar and wind technologies discourages commercialization of other more cost-effective technologies and approaches.
f. These major investments will reduce CO2 emissions by only about 12 million tons/year and encounter growing waste and negative grid impacts.

2. Should a policy-based Social Cost of Carbon be recognized as a limit to cost-effectiveness?
3. Should New England's access to inexpensive natural gas be protected and expanded to support regional grid flexibility and reliability?
4. Should we prioritize subsidies based on carbon abatement cost?
5. Shouldn't additional transmission and distribution expenditures needed to support the expansion of solar and wind generation be evaluated based on their additional carbon abatement costs?
6. What are the negative economic impacts (inflation, loss of business and jobs to other regions, slower or negative economic growth, reduced discretionary spending by consumers, etc.) of major increases in the cost of electricity and how are they distributed among different states and consumer groups?
7. Should consumers be aware of the detailed tax and rate impact of subsidies for solar and wind generation before additional long-term commitments are made?
8. How can market disruptions resulting from growing surpluses be evaluated to protect future grid reliability and to avoid premature loss of investments in wind and solar.
9. Has the magnitude of solar and wind subsidies moved the power industry away from an effective competitive market intended through deregulation, losing the ability of investments to react to market needs?

Recommendations

State energy policies targeting reductions in power grid carbon emissions in New England need to undergo a critical review to evaluate their cost effectiveness and unintended impacts.

1. Each state should produce transparent reports describing how policy initiatives comply with legal requirements for cost effectiveness. An analysis of carbon abatement costs should be presented for a wide range of technology options. Carbon abatement costs should include transmission and distribution changes to support renewable generation. A ceiling on carbon abatements costs should be established based on consideration of a determination of the SCC based on open discussion and public input. The impact of current technology-specific subsidies should be reviewed to determine whether the implementation of other, more cost-effective technologies is being discouraged.

2. Regional studies should be undertaken with ISO NE to evaluate the curtailments likely to result from projected increases in solar and wind generation. The increase of curtailments over time should be considered in projecting carbon abatement costs. Also, the projected occurrence of negative pricing should be carefully evaluated to determine resulting destructive impacts on asset values and longevity of generating resources, potentially impacting future adequacy, flexibility and reliability.
3. FERC should undertake a review of whether renewable energy credits and above-market power purchase agreements with offshore wind and other projects negatively impact fair competitive bidding and investment planning in the wholesale power market. This review should also address the resulting uneven distribution of costs and benefits among states and between regulated and public owned retail electricity suppliers.
4. State RPS targets should be re-evaluated to determine if they should be suspended or redesigned due to declining effectiveness and negative impacts on the wholesale markets. Rapid deployment of additional wind and solar generation will hit an inflexion point in 2024 after which curtailments will grow rapidly with major negative effects.
5. More uniform regional and national energy policy is needed to achieve cost effectiveness and fair distribution of costs and benefits.
6. Immediate discontinuation of subsidies for BTM solar systems should be considered given their extremely high costs and low effectiveness in decarbonization.
7. A comprehensive independent review should be undertaken on behalf of electric customers to determine overall cost effectiveness and rate impacts of regional and state energy policies. Special consideration should be given to carbon abatement costs, curtailments, negative pricing, and overall effectiveness in the context of global efforts and expected outcomes regarding climate. Consumers should be fully informed on how subsidies flow into their electric rates and taxes.

The authors will support selected follow-up studies and reports with several universities and other organizations to extend the application of carbon abatement costs and hourly modeling to more technologies and regions through a new collaborative educational platform, the Center for Academic Collaboration Initiatives (*www.centeraci.com*). The full report and supporting documents will be available at this website.

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2. Introduction and Objectives

Current state energy policies in New England seek major reductions in CO_2 emissions over the next decade. Attempting to achieve "Net Zero" carbon emission targets in New England is limited by the mismatch between the timing of wind and solar generation, loads and other inflexible generation. Adding large amounts of new wind and solar generation exceeds power grid needs, become progressively expensive to consumers and disruptive to the operation of the regional competitive power market. The magnitude of these investments and impact on electric rates and taxes can have substantial negative impacts on the region's economy. The cost-effectiveness of proposed investments must be examined carefully to understand their impacts on consumer costs and on future regional power grid adequacy and reliability.

The objectives of this report are to:

1. Define important characteristics of the New England power grid that will limit the effectiveness of decarbonization initiatives
2. Demonstrate innovative modeling approaches to
   a. evaluate the costs of operating current and added electric generating installations, and to calculate the incremental cost of reducing carbon dioxide emissions (carbon abatement cost)
   b. estimate the hourly dispatch of each generator type, operating costs, wholesale price, and carbon emissions to define power grid behavior as large amounts of renewable generation are progressively added to the grid
3. Evaluate the timing of loads and generation to determine limits where the amount of discarded surplus energy (curtailments) becomes disruptive and costly
4. Evaluate the possible impact of energy surpluses on wholesale pricing as some generators bid negative prices (pay to run) to obtain their subsidies
5. Evaluate the effectiveness of adding battery energy storage(BES) to reduce wasted surpluses and increase reductions in CO_2 emissions.
6. Provide a comparison of projected carbon abatement costs for solar and wind installations and battery storage to support prioritization and to determine overall and relative cost-effectiveness
7. Evaluate the concept of the Social Cost of Carbon to represent the cost of not reducing carbon emissions (cost of damage caused by human carbon emissions) as a metric for comparison with carbon abatement costs to suggest limits on cost-effectiveness and to focus on key uncertainties that should be considered in understanding the cost-effectiveness of decarbonization policies

8. Suggest a review of state and regional policy implications

This report represents the results of three years of work to support teaching energy economics to graduate engineering students at the University of Massachusetts Lowell. Some of the work provided by students occurred through special project-oriented classes, and uncompensated volunteer work. Since no funding was provided for this work, any interpretations and conclusions presented do not reflect the influence of any funding source, private or public. Inputs and comments were obtained by networking with individuals from a number of organizations active in key related areas.

Initiatives are underway to extend the application of the approaches and modeling described in this report to a broader representation of universities in New England and to other regions, given the pervasive need to understand the effectiveness of massive proposed decarbonization investments. The study of energy economics requires a unique and broad combination of knowledge and skills spanning generation technologies and economics, grid and power market operations, power plant project development and financing, asset management, federal policy incentives, state policy incentives, climate science and projected impacts of climate change. This means that effective analysis of climate driven energy policy is extremely difficult and requires collaboration between many individuals and organizations that effectively bring together these and other skillsets and knowledge. This report represents such an effort undertaken by the authors to bring together insights from a network of experts needed for this analysis.

The authors have founded the Center for Academic Collaboration Initiatives (CACI) as a platform for supporting the extension of this work to many universities and regions in the US and around the world. This creates the opportunity to overcome limitations imposed by funding, physical resources, organizational priorities, access to expertise, and availability of participating students and faculty in all of the disciplines. CACI seeks continuing collaborative support and mentoring from a wide range of government agencies, consultants, research institutions and industry to pursue effective and important teaching, research, theses and reports. CACI may also support the opportunity for collaboration in areas outside of energy economics.

3. Current Power Grid Characteristics

Understanding the current demand for electricity, generation capabilities, daily operations, and carbon emissions of the New England power grid forms the foundation for evaluating the cost effectiveness of planned changes over the next decade.

3.1. Grid operations, market management and planning

ISO New England ("ISO NE") is the non-profit Independent System Operator authorized by the Federal Energy Regulatory Commission (FERC) to manage grid operations including generation, transmission, exchanges with other regions, and the operation of a competitive wholesale power market. It is responsible for conducting studies, analyses and planning to ensure long term adequate and reliable supply of electricity to the region.

ISO NE was established with deregulation of the regional power industry in the early 1990's caused a transition from central, regulated power system planning and management to a competitive, free enterprise market-based system. This caused private investment to replace public regulated monopoly ownership of power plants with the intent of promoting innovation and increased efficiencies driven by fair and open competition. Exceptions to this transition include the continuing existence of public power agencies primarily representing municipalities and co-ops (groups of municipalities) which own and operate some generation, and the state of Vermont which still regulates power generation. There are proposals in Maine to re-regulate power generation.

ISO NE operates a competitive wholesale power market with bidding and pricing mechanisms intended to promote investments in plants that support important grid operating criteria including adequacy, flexibility, reliability, and geographic distribution. Generators receive payments for energy, capacity and ancillary services to address those needs. The 2021 Regional Electricity Outlook (ISO New England, 2021) provides an overview of ISO NE roles and activities.

Market supply participants seek profitability by offering energy pricing based on variable (including fuel) costs on a real time, locational basis. They can also bid for capacity payments and to provide ancillary services such as spinning reserve, voltage control and standby power. Some large commercial and industrial consumers can enter into agreements where they reduce their loads during peak or emergency conditions for demand reduction payments.

ISO-NE also plans and oversees implementation of transmission system improvements and recovery of related costs through tariffs. New generation projects typically require new interconnections and some improvements to existing transmission to balance the transfer of power to loads. As regional loads change and some generators retire, ISO-NE can address adequacy, flexibility and reliability criteria by directly pursuing critical transmission improvements or by encouraging investment in certain new generation facilities through market mechanisms. Connections with adjacent power grids (New York and Canada) supply over 20% of regional energy, including important backup resources.

ISO NE operates under the supervision of the Federal Energy Regulatory Commission (FERC) which coordinates power grid oversight in other regions and is ultimately responsible for meeting overall reliability targets. Also, ISO NE must operate within state regulations including environmental rules and climate initiatives.

State energy agencies seeking to implement climate policy now dominate the planning and economics of new generation. Existing solar and wind generation in New England would not exist without historic state policy support. New power generation facilities that will be added over the next decade are driven by state and federal incentives that target specific technologies with the intent to reduce regional CO_2 emissions. This is important because specific subsidies (primarily tax incentives, clean energy credits, and direct offtake contracts from distribution companies) now determine where and how new projects are implemented, rather than wholesale market and power grid needs.

An issue of growing importance is whether the implementation of state climate policies will prevent ISO NE from effectively undertaking their responsibilities in the future, and whether the impact of these policies will prevent wholesale competitive markets from operating properly.

3.2. Current capabilities and generation

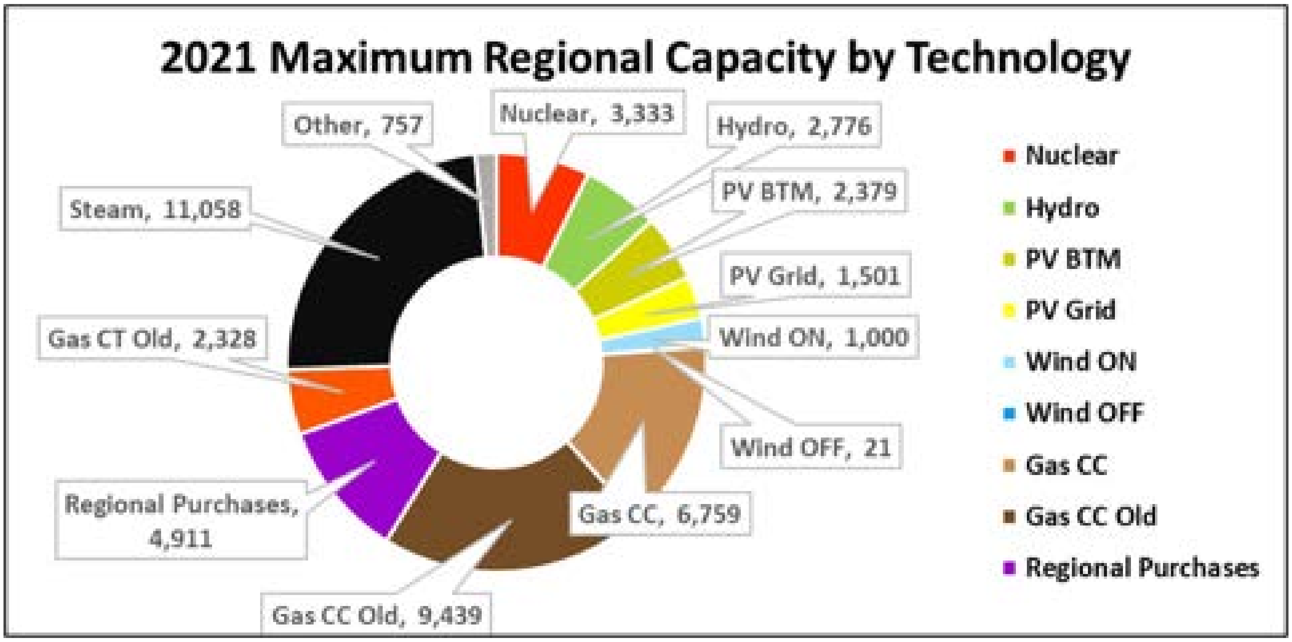
The New England power grid currently functions as one of the most economical, reliable, and low-emitting regional power systems in the US. This is due to the availability of inexpensive natural gas that has economically displaced the use of coal and oil, and the installation of a fleet of modern gas fired plants that provides inexpensive, reliable energy and capacity with the flexibility to match changing load requirements.

Extensive related information about the operation of the regional grid and planning initiatives to address changes resulting from extensive deployment of renewables is available at the ISO New England website. (ISO NE, 2021).

Generating capacity

The chart below in Figure 16 shows 42 GW of current regional generation by type. The maximum capacity from each category reflects changing conditions including sun, wind, temperatures, and water flow, as well as the regional distribution of generators and the likelihood that they can operate at the same time. These values are different than nameplate capacity which represents output of a single unit at a design point, used to calculate installation costs. Maximum capacity is derived from evaluation of actual generating data in 2019 available from ISO NE.

Figure 16 2021 Generation Capability



Onshore wind nameplate capacity is 1454 MW in the 2021 CELT report (ISO New England, 2021), currently including about 30 MW of offshore wind. Given the effect of regional and resource variations, only about 70% of the wind generation nameplate capacity in New England is ever available at the same time. Based on actual generation data, only 1000 MW of onshore wind capacity represents the highest regional output for onshore wind.

Natural gas is the predominant fossil fuel in the New England region. Gas combined cycle plants (CC) and gas combustion turbines (CT) provide over 20 GW of flexible and reliable capacity that is critical to satisfying peak loads. Modern combined cycle power plants represent the best available power industry technology for reliable, flexible, efficient and cost-effective electric power production within tightening environmental restrictions. About 7 GW of newer (installed 2003 or later) gas combined cycle plants currently operate most of the time to satisfy load requirements not met by inflexible generation. About 9 GW of older combined cycle plants operate less often when loads are high and when solar and wind production are not available. About 4 GW of combustion turbines rarely operate during peak or emergency periods. Some gas fired plants can operate for limited periods burning oil when gas becomes expensive or unavailable during extremely cold winter periods. ISO NE is implementing incentives to support investment in fuel oil inventories at dual fuel capability units that rarely run but that improve winter grid reliability.

Over 11 GW of older coal, oil and gas fired steam turbine plants remain in service and can operate during peak and emergency periods and during winter periods when gas supply is constrained by heating use.

The Seabrook and Millstone nuclear plants provide about 3.3 GW of year-round reliable, non-emitting generation. They operate as must-run base load plants normally interrupted only for refueling outages every 18-24 months. These aging nuclear units have high fixed operating costs and require periodic capital investments for nuclear safety compliance and life extension. They may not receive sufficient revenue when regional prices are set by gas combined cycle plants with low gas prices, or during surpluses when prices drop sharply. Current state support is provided for these units when gas prices are low, based on their ability to produce power without CO_2 emissions.

Over 2.7 GW of hydroelectric power generation provides variable non-emitting energy and important pumped storage flexibility. About 1.5 GW at the Bear Swamp and Northfield Mountain pumped storage facilities operates through daily charging/discharging cycles and provides important grid flexibility and control. A large number of smaller and aging hydro plants operate based on the varying availability of water flow and some reservoir capacity.

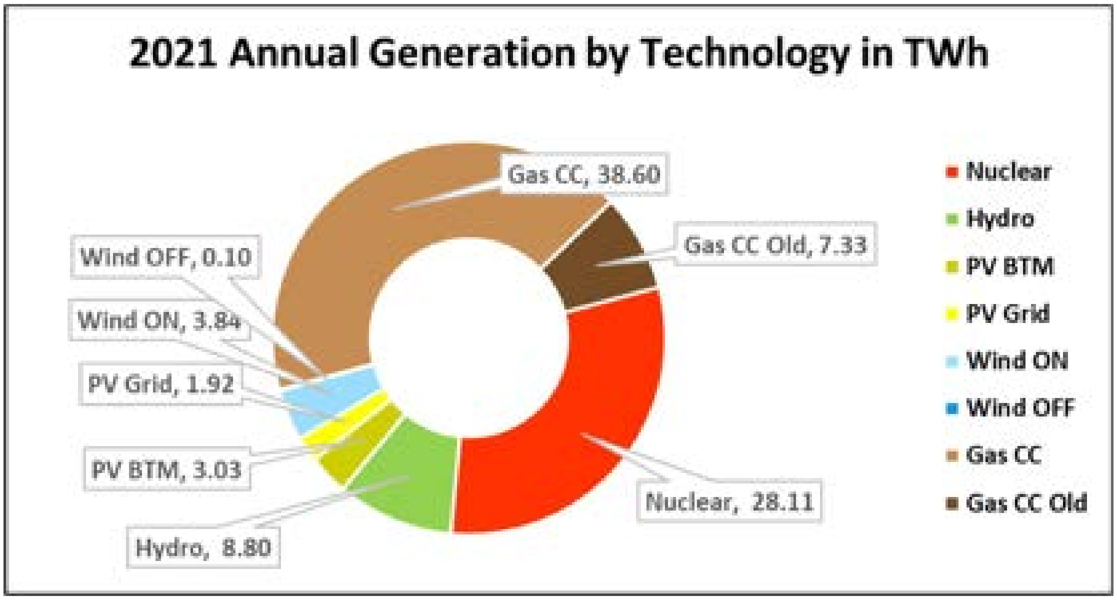
About 1.1 GW of "Other" capacity represents wood-fired and municipal solid waste (MSW) plants in the region and a small amount of landfill gas generated electricity.

About 20% of the region's electricity is purchased from Canada representing about 3.1 GW of capacity which is mostly from hydro plants, and about 1.8 GW of mainly gas combined cycle plants in NY.

Annual energy production

As shown in Figure 17, New England's 100 TWh of annual native generation is dominated by gas combined cycle plants (46 TWh) and by nuclear power (28 TWh).

Figure 17 Regional Generation in 2021 in GWh



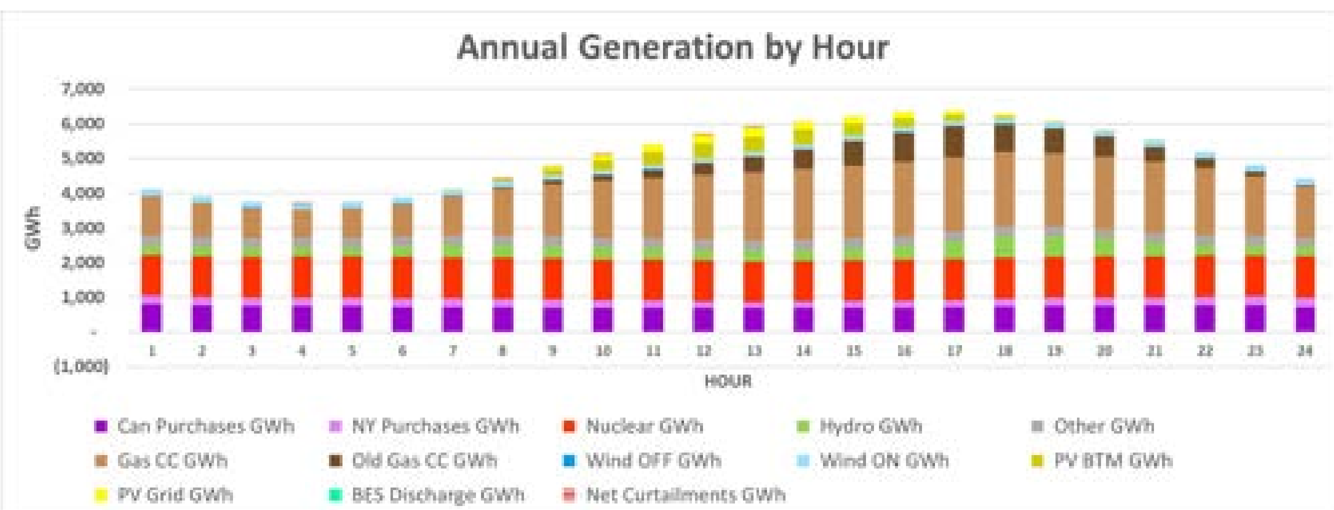
1 terawatt-hour (TWh) = 1000 megawatt-hours (MWh)

Hourly dispatch

Combined cycle plants operate every hour to track changing loads. Older combined cycle plants operate in the evenings as loads increase and as solar generation declines.

Figure 18 below shows total annual generation by technology by hour in 2021. It is important to note that most gas generation occurs in the evenings.

Figure 18 2021 Annual Generation by Hour



A large amount of this regional generation is inflexible, and normally doesn't respond to load changes without intervention by ISO-NE. Inflexible generation includes solar, wind, nuclear, some hydroelectric plants, and portions of "Other" generation such as municipal solid waste fired plants and landfill gas plants. Wood fired plants represent a small amount of regional capacity and are modeled as inflexible units, although they tend to maximize output during periods when electric rates are highest. Purchases from Canada are assumed to be inflexible and vary based on historic patterns, although arrangements are being investigated to add some flexibility to these purchases.

Purchases from New York are primarily based on the operation of gas combined cycle plants similar to those in New England, driven by inter-regional pricing opportunities.

Hydroelectric power generation includes dispatchable pumped storage that provides some system control and discharges in the evenings. Most hydroelectric generators have limited or no reservoir capacity and operate based on water flow.

Gas combined cycle plants provide very little generation at night during low loads. Some amount of gas fired generation is always in operation to provide control flexibility. Three percent of maximum annual load is assumed for modeling purposes as the minimum dispatchable capacity required from gas combined cycle plants or battery energy storage.

Some of the inflexible generation must be shut down or "curtailed" when it exceeds load requirements and transmission limits. Curtailments occur rarely but will become more important as more wind and solar generation is added.

Competitive wholesale market

Revenue is available to owners of generators through participation in competitive markets for energy, capacity and ancillary services. Most plant owners are privately owned businesses that remain profitable when revenue from these markets is sufficient to cover their fixed operating costs and to provide a competitive return on investment. ISO-NE manages these markets through competitive bidding processes based on projected needs for generation adequacy and reliability.

Energy pricing is set competitively through a regional process where the highest bidder sets the regional price, subject to some differences for locational constraints. Currently wholesale energy pricing is normally set by gas combined cycle plants except during limited periods of very high summer loads, when gas supply becomes limited due to heating demand on the coldest winter days, and when loads are very low overnight. Energy prices set by gas combined cycle plants are usually based on a combination of natural gas prices and variable operating costs. Fluctuations in regional gas pricing represent the combined effect of a variety of long-term supply agreements and spot prices. Gas pricing, and resulting regional energy prices, tend to increase during peak periods as more generation uses spot prices. Prices tend to decrease during night-time periods as more efficient generation uses lower cost gas from long term contracts. Most actual gas supply arrangements are confidential due to market competition, so modeled gas pricing is based on historic variations during the year and treated as a high-level variable that can be evaluated to understand economic sensitivities.

Gas combined cycle plants receive capacity payments that help cover annual fixed costs to cover permanent staffing, scheduled maintenance, and taxes. Older gas combined cycle plants were designed to operate continuously, but now operate a small percentage of the year, and rely increasingly on capacity payments to stay profitable. Many of the older steam plants, which have substantial fixed costs, are expected to retire over the next decade if the amount of capacity payments received annually through competitive bidding are insufficient for profitability.

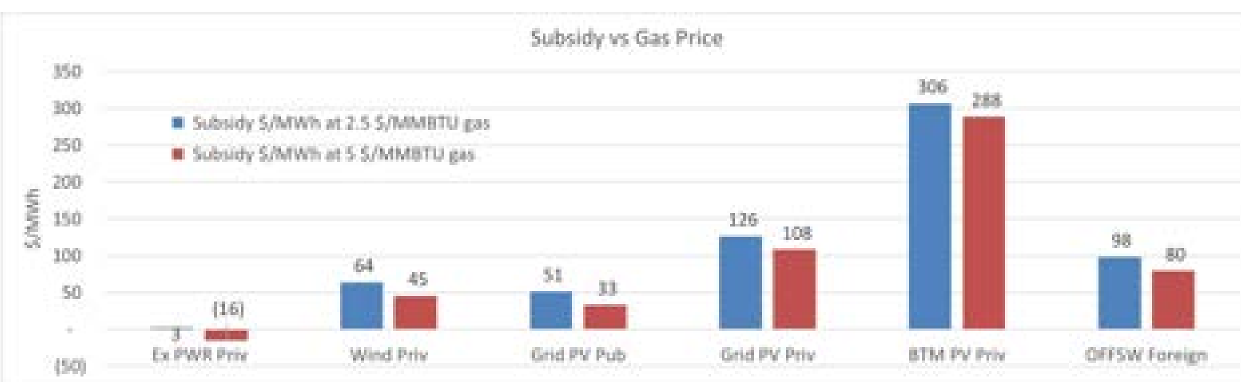
When disruptive changes to grid operations occur that threaten generation adequacy or reliability, ISO-NE can adjust market mechanisms and arrange for special payments to certain generators until long-term market-driven corrective changes occur. Older steam plants provide important stand-by capacity that may be needed during emergency or extreme grid conditions at key locations. Their projected retirement is carefully reviewed by ISO-NE to consider the need for other changes to generation or transmission.

State and federal subsidies

State and federal subsidies for clean energy now dominate the planning and implementation of new generation in New England. Investment tax credits now cover a large fraction (30+%) of the investment cost of some facilities. Accelerated depreciation further reduces the effective capital cost of some projects. Clean energy credits provide payments that are larger than the market value of electricity, in some cases by an order of magnitude. Power purchase agreements can support state mandated projects by paying several times the market value of generation.

The total value of subsidies for each technology shown in Figure 19 is estimated by subtracting the cost of fuel and variable operating costs for gas combined cycle plants from the life cycle production cost of each technology, described in Section 4.4 Reference designs and costs.

Figure 19 Estimated Subsidies to Date in $/MWh



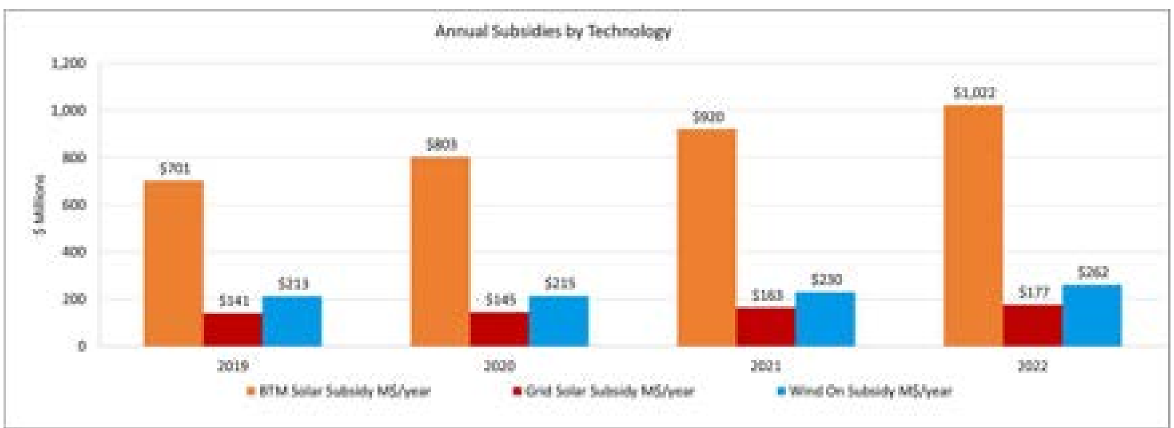
Assumes 2021 dollars with no inflation

The subsidy required to support continued operation of existing nuclear plants is sensitive to life extension cost assumptions but may disappear with higher gas prices. Due to lower capital recovery costs, public owned grid PV requires lower subsidies than privately owned plants. Subsidies for behind the meter (BTM) PV systems are highest and less sensitive to changes in gas pricing.

Not only do these subsidies impact the development and financing of new generation facilities, but they also influence bidding in the competitive energy market during surpluses, when curtailments threaten receipt of subsidies. For example, the federal production tax credit, often used by wind generation projects, is awarded based on actual generation. This provides an incentive for the owner of a wind generator to offer lower or negative energy pricing to avoid being curtailed during periods of surplus inflexible generation. Similarly, state clean energy credits provide payments for actual generation and can result in lower or negative pricing by solar and wind generators. State mandated power purchase agreements, such as for offshore wind generation, establish incentives and penalties in the event of curtailments which could result in bidding negative prices.

Total recent annual subsidies for wind and solar generation in New England are estimated based on total installed capacity in the following chart in Figure 20.

Figure 20 Annual Subsidies for Wind and Solar 2019-2022



As shown above most of the recent subsidies support behind the meter (BTM) solar installations even though these installations provide relatively small energy production.

Negative pricing impacts energy revenue to all generators by making them pay to run during those periods. All inflexible generation (including nuclear, some hydro, solar and wind) suffers economically from negative pricing through loss of annual revenue and the related drop in asset value. As more renewable generation is forced into the grid through state and federal incentives, there will be increasing surpluses and rising potential for earlier retirement of assets that lose income. This can result in market forces that drive a long-term shift in value from energy to capacity, lowering payments for energy and increasing payments for reliable capacity.

Federal subsidies for natural gas production are very small in comparison. According to the US Energy Information Administration (US EIA, 2018), the annual value of tax incentives for natural gas production is about $3 billion. With an annual production of about 33 quadrillion BTU, this amounts to less than $0.10/MMBTU, which is neglected given variability in gas pricing assumptions.

Growing subsidies now dominate the planning and financing of new plants, as market income reflecting market needs has a declining role in attracting investment.

3.3. Recent investments in renewable power generation

Clean energy subsidies have resulted in the investment of more than $11 billion to install about 5.3 GW of solar and wind generation by 2021 as shown in Figure 21. In addition to these investments in renewable generation capacity, additional costs are incurred in related modifications to transmission and distribution systems, and for higher operating costs to maintain grid reliability and flexibility as supply variability increases.

Existing solar and wind generation facilities include wind farms, distributed behind the meter (BTM) installations, and grid-connected photovoltaic (PV) installations. Photovoltaic (PV) generation capacity currently represents over 4.8 GW (ISO New England, 2021) at the end of 2021. This capacity includes grid connected and behind the meter (BTM) installations which displace output from gas combined cycle plants during hours of sunlight. New England produces its maximum regional PV output only about 15% of the time on average based on 2019 data.

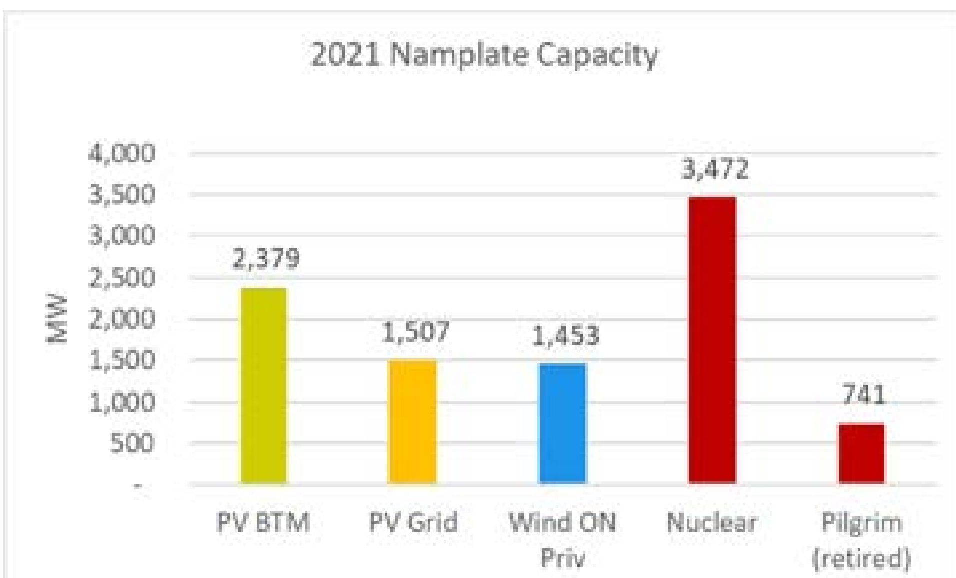
These investments have been driven by tax credits, net metering and state clean energy credits (RECs) that support increasing state renewable energy portfolio standards. In many cases the value of federal and state subsidies exceeds the total costs of these installations.

Figure 21 2021 Cumulative Investments in Renewables

Total investments in clean energy as reported by Statistica (Statista, 2022) exceeded $100 billion per year in 2021.

The cumulative installed capacity of wind and solar now exceeds that of nuclear generation in the region as shown below in Figure 22. The Pilgrim nuclear station retired in 2019 but is shown for comparison.

Figure 22 Installed Renewable and Nuclear Capacity 2021



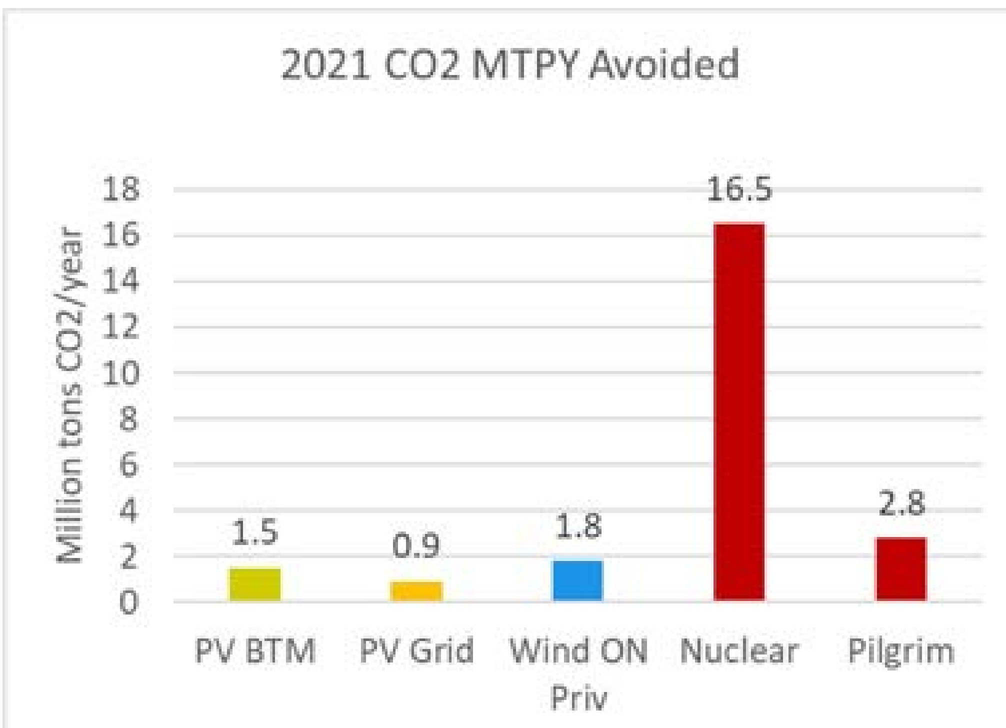
Wind generation currently represents about 1.5 GW of capacity (ISO New England, 2021) but less than 1 GW is produced at any moment due to regional wind resource distribution.

3.4. Current regional CO2 emissions

The operation of nuclear, wind and solar generators in New England reduced the operation of gas combined cycle plants, with estimated reductions in CO2 emissions shown in Figure 23. Although the region's 5.2 GW solar and wind generation capacity exceeds the 3.3 GW of operating nuclear capacity, it offsets only about 4.2 million tons/year of CO2 emissions, relative to 13.7 million tons/year offset by the three operating nuclear units. If the Pilgrim nuclear station had not been retired, it would be avoiding another 2.8 million tons/year.

Although BTM solar capacity represents the largest recent decarbonization investment ($6.5 billion), it provides a relatively small decarbonization effect (about 1.3 million tons/year). The investment in BTM solar is clearly disproportional to its effectiveness, as will be further shown through the evaluation of carbon abatement costs.

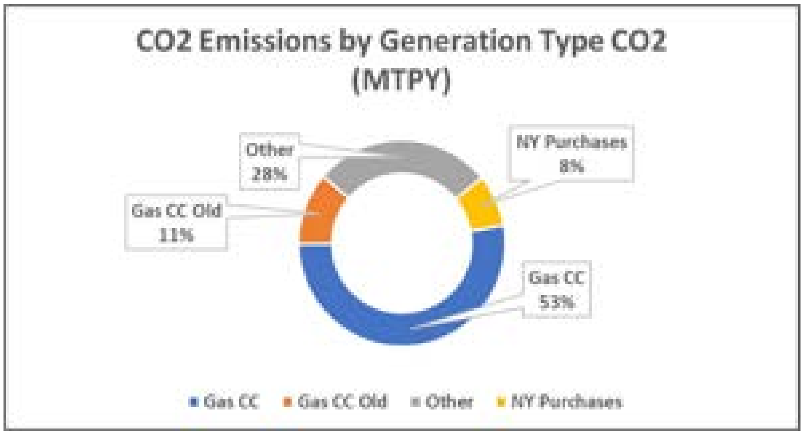
Figure 23 Current Wind and Solar CO2 Reductions



New England 2021 CO2 emissions from power generation were about 33 million tons per year. Worldwide 2020 CO2 emissions from fossil fuels were about 40 billion tons per year, with about 5 billion tons per year from the US. (European Commission, 2022)

Regional CO2 emissions are dominated by the operation of gas combined cycle plants as shown below in Figure 24. NY purchases are primarily from the operation of gas combined cycle units in that region. The “Other” category represents wood fired, municipal solid waste (MSW) and landfill gas power generation.

Figure 24 Major Regional CO2 Emission Sources in 2021



These estimates are developed based on the generation and emission rates shown below in Table 1. Emission rates were estimated to match annual emissions published by ISO NE and others. CO2 emissions from New England power generators are reported by the U.S. Environmental Protection Agency (EPA) but take several years to update.

Table 1 Basis for Estimating 2021 CO2 Emissions

	GWh/yr	CO2 tons/MWh	CO2 (MTPY)	CO2 (MMTPY)
Gas CC	39,908	0.45	18,052	16,376
Gas CC Old	6,084	0.51	3,125	2,835
Gas CT	8	0.58	5	4
SUBTOTAL	46,000	2.22	21,181	19,215
Other	6,639	1.39	9,229	8,372
SUBTOTAL	52,639	3.61	30,410	27,587
NY Purchases	5,608	0.48	2,709	2,457
TOTAL	58,247	-	33,118	30,045

MTPY=million tons per year; MMTPY=million metric tons per year

CO2 emissions decline annually as the amount of power generation from gas combined cycles is reduced by progressive installation of solar and wind generation.

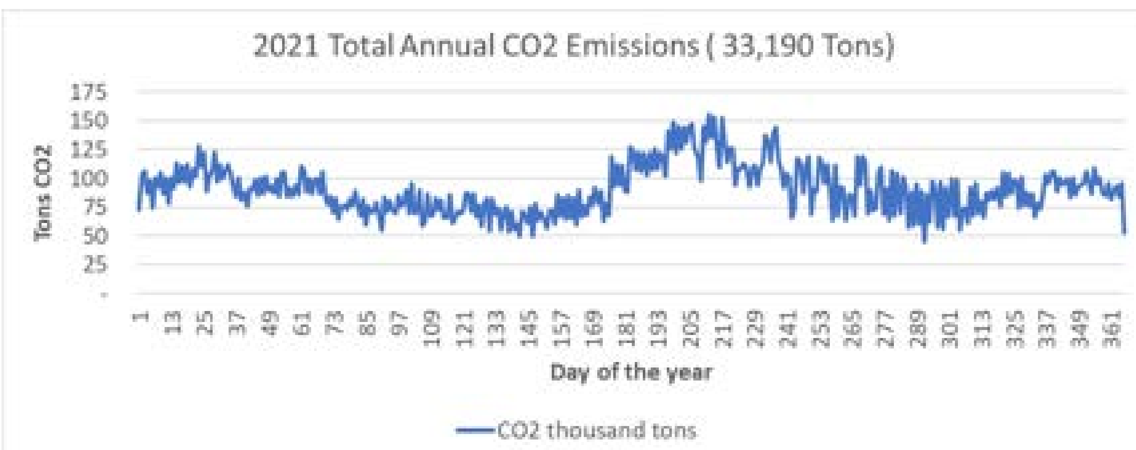
CO2 emissions from gas combined cycle plants vary based on their conversion efficiency (heat rate) and the number of hours they operate. Some gas fired combined cycle plans switch to oil firing during short periods in the winter when gas supply is restricted for heating use. Operation of old oil and coal fired steam units during emergencies and extreme conditions is rare and does not contribute significantly to annual regional CO2 emissions.

Some of the annual CO2 emissions can be attributed to necessary grid operational flexibility provided by gas fired units and by some hydro units. This becomes important in understanding how much gas generation can be offset by renewables without encountering operational problems. ISO-NE continues to study how much flexible generation is needed to enable system control with large increases in solar and wind generation. (ISO New England, n.d.) Some indication of this requirement can be obtained by observing how much gas generation is operational when there is surplus energy available that is curtailed. A value of 3% of the maximum annual load is assumed for modeling purposes which is much smaller than the amount of gas generation which currently occurs during hours when there are curtailments. Future addition of new inverter technology on solar, wind and battery systems are projected to provide ways to reduce reliance on gas units for system flexibility and control (ISO NE, 2016).

The New England power grid imports and exports power from other regions, which impacts regional CO2 emissions. Imports from New York tend to come from gas fired generation, while imports from Canada represent mostly hydroelectric generation.

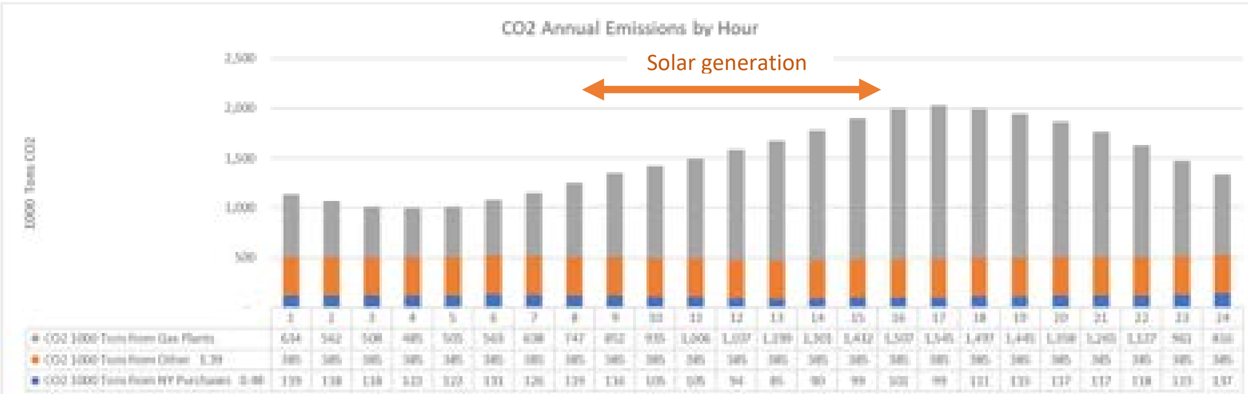
As shown below in Figure 25, carbon emissions in New England are highest in the winter months when solar generation is low, and in the summer when evening air conditioning loads peak causing less efficient gas units operate.

Figure 25 2019 Daily CO2 Emissions



The opportunity to reduce CO2 emissions is limited by the timing of added generation relative to the behavior of other generation, regional purchases and changing loads. Highest emissions occur during evening peak load periods when solar generation declines, during summer peak load periods, and during winter periods when the solar resource is lowest. Annual CO2 emissions by hour are shown below in Figure 26.

Figure 26 2021 CO2 Emissions per Hour



This chart provides an indication of the limits to CO2 reduction by adding solar and wind generation. It is important to consider the timing of emissions on an hourly basis and compare the timing of solar and wind generation. Hourly modeling measures these limitations by considering variations over time in resources, loads and inflexible generation.

Emissions drop mid-day as solar power production occurs. More than half of the CO2 emissions occur in the evenings after hour 15. Peak CO2 emissions occur in the evening with peak system loads and the absence of solar power production. Doubling solar generation will only reduce CO2 emissions during mid-day, while most CO2 is produced in the evenings. Wind generation only occurs 30-50% of the time, which means that the bulk of CO2 produced in the evenings can be reduced by less than half. Progressive addition of solar and wind generation becomes less effective as more energy is produced during hours where gas generation cannot be reduced further.

3.5. State and federal energy policy targets

Current state and federal energy policy initiatives aggressively target reductions in emissions of carbon dioxide from the use of fossil fuels in electric power production.

President Biden announced targets to achieve a carbon pollution-free power sector by 2035 and a net zero emissions economy by no later than 2050.

Most New England states are targeting "Net Zero" CO2 emissions by 2050, which on a regional basis represents an 80% reduction from 2009 power sector emission rates (55 million tons/year) to about 11 million tons per year by 2050. Specific state legislation and emission reduction mandates are summarized below (ISO New England, 2021). Most of the state legislation establishing these mandates has some reference to achieving cost-effective emission reductions, but specific criteria for achieving cost-effectiveness are not provided.

Interpreting these goals as the basis for determining required reductions in power sector carbon emissions is difficult given different approaches in each state. Also, many state implementation plans seek to reduce building and transportation emissions through electrification which will increase power sector emissions. Further study is needed to fully understand timing and grid behavior in response to building and transportation electrification.

Decarbonization options for buildings and transportation include electrification to shift from the use of fossil fuels to more electric generation, which may result in increased operation of gas power generation with increased emissions. Substituting electric vehicles for gasoline and diesel engine vehicles and substituting electric heat pumps to replace oil and gas heating systems are likely to increase the use of gas fired power generation by increasing loads during periods when solar and wind are not available.

Table 2 summarizes New England state legislation and requirements for decarbonization.

Table 2 New England State Mandates for Greenhouse Gas Reductions

State	Legislation	Mandate
Maine	Act To Promote Clean Energy Jobs and To Establish the Maine Climate Council (2019)	Requires the state to reduce GHG emissions to 45 percent below 1990 levels by 2030 and 80 percent by 2050.
Connecticut	Act Concerning Connecticut Global Warming Solutions (2008)	Requires the state to reduce its GHG emissions to 80 percent below 2001 levels by 2050. In 2018, the state established an interim benchmark for GHG emissions reductions of 45 percent below 2001 levels in 2030.
Rhode Island	Resilient Rhode Island Act (2014)	Requires the state to reduce GHG emissions to 80 percent below 1990 levels by 2050.
Massachusetts	Global Warming Solutions Act (2008)	Requires the state to reduce GHG emissions to 80 percent below 1990 levels by 2050. In 2020, using the authority under the Global Warming Solutions Act, the Massachusetts Executive Office of Energy and Environmental Affairs issued a letter of determination setting a net zero emissions limit by 2050.
Vermont	Act Relating to Addressing Climate Change (2020)	Requires the state to reduce GHG emissions to 26 percent below 2005 levels by 2025, 40 percent below 1990 levels by 2030, and 80 percent below 1990 levels by 2050.
New Hampshire	New Hampshire Climate Action Plan (2009)	Calls for an 80 percent reduction in GHG emissions below 1990 levels by 2050.

Pathways to achieve targeted reductions in regional CO2 emissions from power generation have been explored in several recent studies and planning documents. E3's recent report (Energy Environmental Economics and Energy Futures Initiative, 2020) evaluates potential regional emission reductions and the growth of electrical loads resulting from electrification of transportation, building and industrial energy use. E3 interprets regional policy decarbonization targets for the electric power sector to achieve 95% of regional energy production from carbon free generation by 2050 with about 2.5 million TPY CO2 emissions. Achieving 2.5 million TPY will require eliminating the operation of gas combined cycle plant and substantially reducing the operation of the regions wood, municipal waste and landfill gas facilities. Also, it will require a shift to other technologies, such as energy storage, alternate fuels and a new generation of advanced flexible nuclear generation to maintain system reliability, flexibility and control.

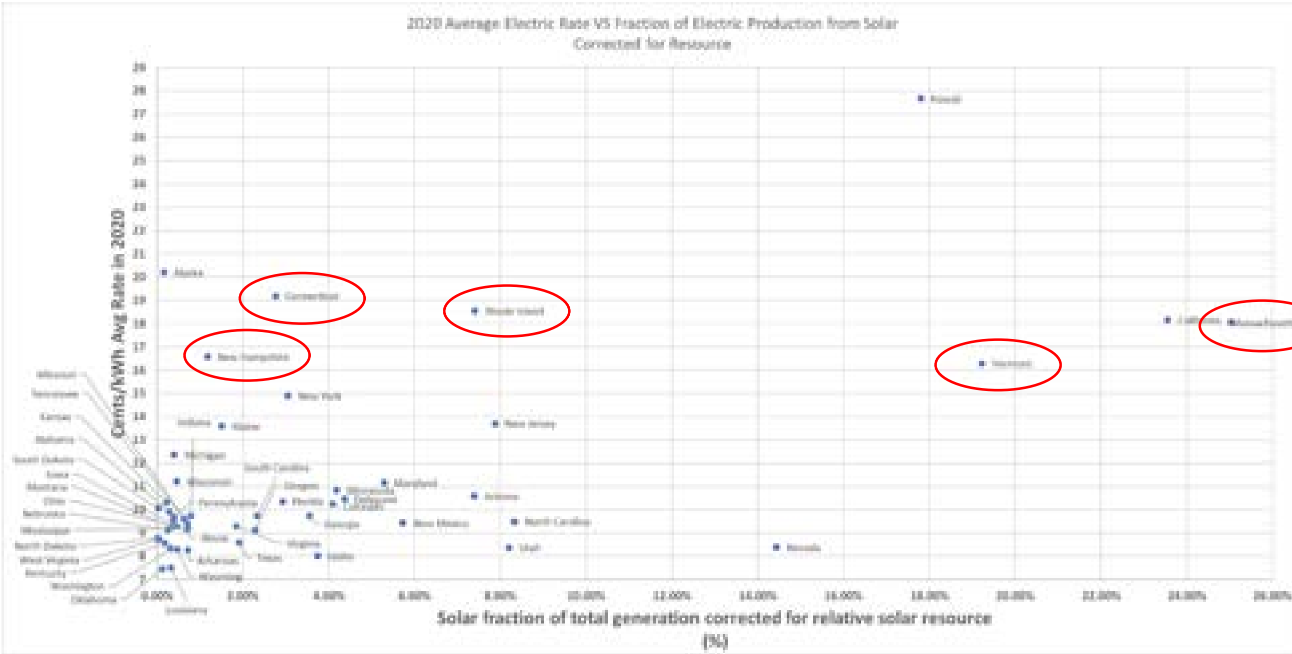
3.6. New England electric rates

The cost of subsidies for solar and wind generation has a substantial impact on consumer electric rates as demonstrated by rapid rate increases in California and much of Europe. Rising electric rates drive inflation, move businesses and jobs to other regions, and reduce consumer spending on other products and services with broad economic impacts.

New England electric rates have grown much faster than the US average, impacted by the cost of clean energy credits, state mandated projects, net metering, transmission and distribution improvements unique to adding solar and wind facilities. Massachusetts represents about half of the energy consumption in New England and consumes about twice as much electricity than it generates. Massachusetts' aggressive policy support for renewable power generation has contributed to rapid growth in electric power bills to almost twice the national average, even though the regional wholesale market gives access to the low cost power based on efficient use of inexpensive gas.

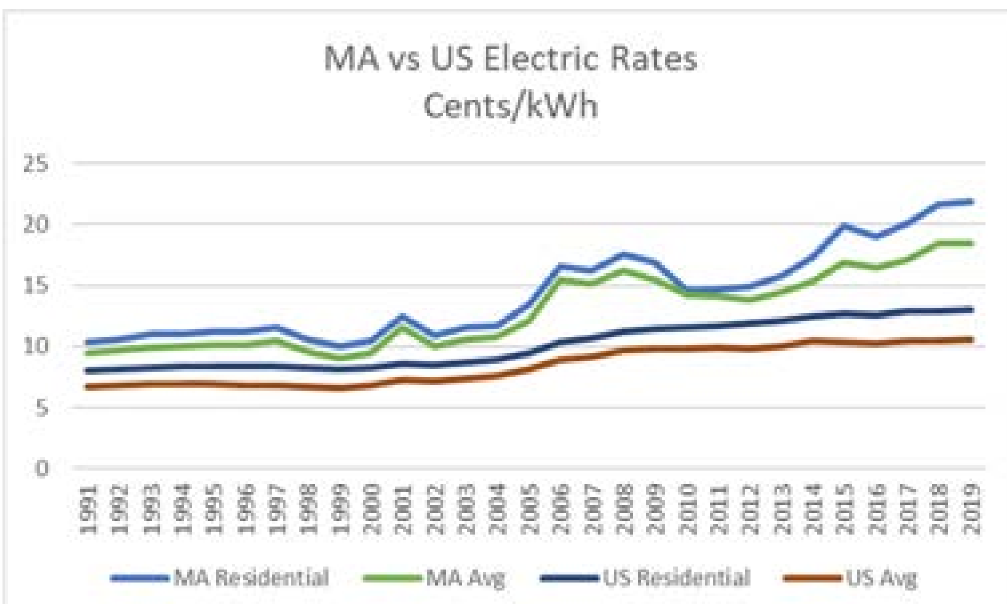
Recent increases in consumer electric bills reflect the additional costs of decarbonization policies. According to the US Energy Information Administration, the average retail price of electricity in the U.S. was 10.54 cents/kWh in 2020, while the average price for Massachusetts was 18.4 cents/kWh which was only exceeded by a few states. (EIA, 2021) The chart in Figure 27 below compares average state electric rates with the percentage of electric generation from solar corrected for relative solar resource.

Figure 27 Relationship of 2020 Electric Rates to Solar Projection Adjusted for Resource



A historical comparison of US and Massachusetts residential and average electricity prices is shown below in Figure 28.

Figure 28 MA vs US Historical Electric Rates



Source – US EIA

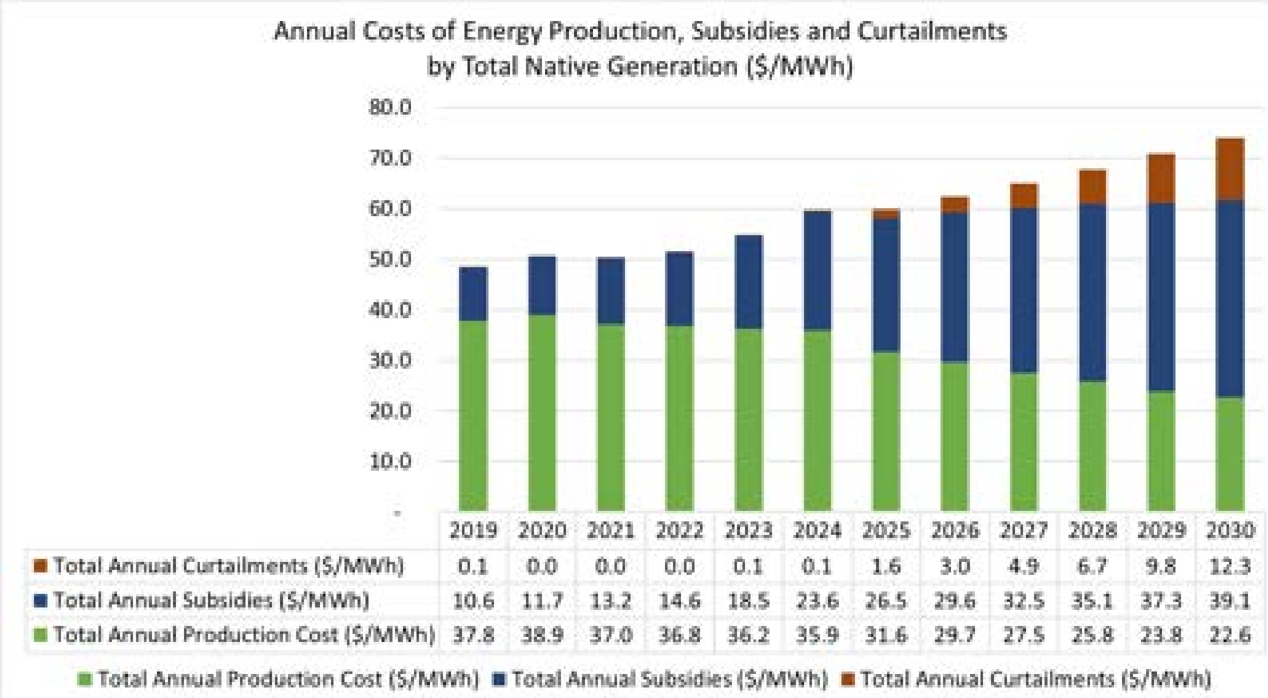
During the period from 2014 to 2019, solar generation in MA more than tripled from 931 GWh to 3280 GWh. During the same period average electric rates increased about 20% from 15.4 cents/kWh to 18.4 cents/kWh. Increases in electric rates reflect a number of different factors such as fuel prices, plant retirements (e.g., Pilgrim Nuclear Station in 2019), new investments in transmission and distribution, growing cost of net metering for BTM solar installations, state required contracts with renewable energy projects, and the impact of including progressively higher costs for renewable energy credits in electric bills.

A report issued by the US International Trade Commission (ITC) (US International Trade Commission, 2021) attempts to relate reductions in CO2 emissions with corresponding increases in consumer electric rates. The report includes a comprehensive description of related information and concludes that "Massachusetts can meet its increased renewable and clean energy commitments with relatively small increases in the retail electricity rates charged to residential and commercial consumers." An extensive bibliography includes listings of other studies that address rate impacts of renewable subsidies. This study considers the increases in costs to consumers due to increases in renewable energy credits, as well as decreases resulting from the market impact of increased renewables generation in the power grid resulting in lower wholesale prices. It does not address tax subsidies, such as tax credits or accelerated depreciation. It did not include hourly modeling of the grid to evaluate curtailments and applies generalized levelized cost analysis for various scenarios subject to many assumptions. It excludes BTM generation which draws the highest subsidies and has a substantial rate impact. It does not consider the impact of state mandated projects financed through utility rate base, or the cost of transmission and distribution improvements. It considers reductions in wholesale pricing resulting from surplus renewable generation but does not include the costs (higher capacity and ancillary services payments) for retaining the fleet of gas fired combined cycle plants needed for grid reliability and flexibility. For these reasons, its presentation of results appears to be very misleading. Additional work is required to provide a clear understanding of policy driven electric rate impacts.

Contrary to the conclusions of the US ITC report, projected indicative wholesale market prices, subsidies, and cost of curtailments, shown in Figure 29 below and discussed further in Section 7, show an alarming rise in the basis for electric rates. Large investments in transmission and distribution improvements are not included which will add substantially. Subsidies are likely to be higher due to inefficiencies, and results are sensitive to gas price fluctuations. These projected subsidies include tax benefits such as tax credits and accelerated depreciation. Estimates are based on 2020 dollars, and $3/MMBtu gas.

Electric rates vary widely by state, type of customer and other factors. The models developed for this report do not attempt to calculate specific electric rates.

Figure 29 Projected Production Cost, Subsidies and Curtailments



	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Total Annual Curtailments ($/MWh)	0.1	0.0	0.0	0.0	0.1	0.1	1.6	3.0	4.9	6.7	9.8	12.3
Total Annual Subsidies ($/MWh)	10.6	11.7	13.2	14.6	18.5	23.6	26.5	29.6	32.5	35.1	37.3	39.1
Total Annual Production Cost ($/MWh)	37.8	38.9	37.0	36.8	36.2	35.9	31.6	29.7	27.5	25.8	23.8	22.6

4. Calculating Carbon Abatement Cost

A primary objective of this report is to demonstrate the calculation of carbon abatement costs as a metric for evaluating the relative cost-effectiveness of decarbonization options in New England. This methodology is intended to support energy policy development and review, as well as teaching and research related to energy economics.

Carbon abatement cost is defined as the unsubsidized cost of adding new lower-emitting facilities, minus the savings from reduced operation of existing plants, divided by the number of tons CO2 that are displaced.

Wind and solar electric generation in New England are only attractive for investment because of policy subsidies targeting reductions in CO2 emissions. These currently include tax credits and accelerated depreciation, clean energy credits, net metering and state regulatory mandates. For example, electric distribution utilities are directed by the state regulator to finance and build battery energy storage installations, and to contract directly with offshore wind producers. These costs and long term obligations are included in approved electric rates.

Therefore, unsubsidized carbon abatement cost provides the primary measurement of the cost effectiveness of these subsidies in reducing carbon emissions. Carbon abatement cost can support economic prioritization of options and can be considered relative to a Social Cost of Carbon (SCC) as a limit to avoid poor investments and wasteful subsidies where costs exceed benefits.

4.1. Background

Using emission abatement cost as a metric for requiring environmental controls has a long history and includes the economic analysis of reducing emissions of pollutants such as sulfur oxides, nitrogen oxides and particulates. The determination of Best Available Technology by the US Environmental Protection Agency has considered abatement costs to drive emission reductions in areas not in compliance with air quality standards. (Environmental Protection Agency, 2021)

Calculation of carbon abatement costs has recently been addressed in several economic studies. A recent paper "The Cost of Reducing Greenhouse Gas Emissions" (Gillingham & Stock, 2018) provides a review of carbon abatement costs measured by 50 economic studies of policy initiatives over the last decade. It shows a wide range of abatement costs relying primarily on high level analyses which did not consider important details regarding the displacement of carbon emissions or the hourly interactions between renewable power and the existing power grid.

More recently, Energy and Environmental Economics and Energy Futures Initiative issued a report "Net-Zero New England: Ensuring Electric Reliability in a Low-Carbon Future. (Energy Environmental Economics and Energy Futures Initiative, 2020), which models a number of scenarios to achieve Net Zero carbon emission targets for New England and presents a range of carbon abatement costs that increase as lower emission targets are approached. The carbon abatement costs presented by E3 are significantly lower than those evaluated in this report because its analysis does not include BTM solar, which is the most expensive technology. Also, their use of levelized costs for various generation technologies does not remove subsidies, assumes generic capital recovery costs (without regard to ownership), and uses optimistic cost projections for renewables provided by NREL.

A valid evaluation of carbon abatement costs must compare realistic unsubsidized production costs with the cost of displaced electricity considering hourly grid interactions, loss of unusable generation when it exceeds market needs, and other effects of replacing flexible gas power generation with inflexible renewables.

4.2. Required knowledge and skills

A rigorous approach of economic analysis and hourly grid modeling requires substantial multi-disciplinary knowledge and skillsets, obtained by networking and collaboration with many experts. The field of energy economics is multidisciplinary often extending beyond the capabilities of individuals, universities, and even large organizations. Evaluating the economics of decarbonization requires a combined understanding of energy technologies, how plants are built and financed, utility regulation, life cycle economics, power grid operations and planning approaches. These areas are important not only in teaching and research, but in the application and interpretation of carbon abatement cost as a metric for evaluating policy proposals.

Key knowledge areas include:

- Engineering knowledge of key technologies, fuels and resources to interpret design and operational characteristics and limitations that impact grid operations and economics.
- Experience with actual projects to interpret siting and environmental constraints, project scope, cost estimates, schedules and project risks as applied to economic analysis and projections.
- Experience with plant operations and maintenance to support interpretation of costs, dispatch, degradation, outages and operational flexibility.
- Project financing experience to understand the impact of different forms of ownership on economic assumptions, investment decisions and planning horizons, and what conditions prompt new investment, life extension and retirement of existing investments.

- Modeling skills to allow efficient and reliable simplified modeling approaches, self-documenting features, and to support transferability to other users and regions for a range of research and teaching applications.
- Power grid operations in terms of transmission and distribution design and operations, dispatch of large numbers and type of generation, operation of wholesale markets and pricing, load behavior, energy exchanges with adjacent regions, system reliability, flexibility and control, and forecasting changes to loads and generation with varying resources.
- Experience with energy policy mechanisms, subsidy structures and regulation as the basis for setting environmental goals, jurisdictions, economic criteria, planning timeframes and overall effectiveness and priorities in economic modeling and projections.

These areas of knowledge are required to assemble and understand the variety of data and assumptions needed for hourly modeling of the grid to allow calculation of CO_2 emissions displaced by adding renewable generation and the determination of carbon abatement costs.

4.3. Calculation approach

Carbon abatement cost is simply the subsidy required for new lower-emitting facilities per ton of CO_2 avoided presented on a current year or levelized basis.

$$\textit{Carbon abatement cost} = \frac{\textit{(cost of new generation) – (savings from avoided generation)}}{\textit{tons of CO2 avoided}}$$

Carbon abatement cost is determined as \$/ton CO_2. Cost of new generation, savings and additional costs can be included as \$. These values are levelized over the economic life of the new low carbon generation. This analysis assumes that there is no real growth in any costs over the economic life. First year costs can be used to simplify understanding of the process and to reduce the complexity of associated assumptions and economic projections. Tons are used as 2000 lb, while some similar analyses use metric tons (tonnes) as 1000 kg.

For example, the unsubsidized power production cost of a new 200 MW privately financed onshore windfarm in New England is \$84.53/MWh and it displaces 752,000 MWh per year of electricity (based on an average capacity factor of 42.9%) otherwise produced by gas combined cycle plants, which emit an average of 0.39 tons CO_2 per MWh costing an average of \$39.20/MWh (based on \$5/MMBtu gas price). The carbon abatement cost is the difference in cost (\$84.53-39.20/MWh) divided by 292,000 tons of CO_2 avoided (752,000 MWh x 0.39 tons CO_2/MWh), resulting in \$116.7/ton CO_2. This result is sensitive to a number of economic, financing, cost and performance assumptions. Since non-CO_2 emitting technologies are capital intensive, carbon abatement cost is very sensitive to capital cost recovery per kWh, which is very sensitive to cost of capital (based on ownership) and to annual operating hours which are established by hourly modeling.

4.4. Reference designs and costs

Performance characteristics and unsubsidized costs are developed for solar, wind, nuclear, and battery energy storage installations are defined for New England conditions. Hourly modeling of the New England power grid determines CO2 emission reductions based on reduced operation of gas combined cycle plants.

Carbon abatement costs are calculated based on cost and performance assumptions for representative existing and new installations which have the greatest impact on future CO2 emissions.

Existing gas combined cycle plants

The fleet of operating combined cycle plants in New England is divided into two categories to simplify modeling. Older gas combined cycle plants installed before 2003 represent less efficient turbine technology with higher plant heat rates. Newer plants installed after 2003 represent the most efficient and lowest emitting gas power generation technology. Combined cycle plants that can operate on oil are not modeled separately since operating on oil happens infrequently and represents a very small portion of CO2 emissions.

Operating costs and heat rates are obtained from the DOE EIA 2020 Energy Outlook, summarized below for a range of fuel prices. Heat rates are adjusted to match data provided by ISO-NE to represent average operating conditions. Currently operating gas combined cycle plants set regional wholesale electric rates most of the year, bidding into the competitive wholesale energy market based on their fuel cost and variable operating cost.

The cost of producing power from existing gas combined cycle plants provides the basis for calculating Carbon Abatement Cost. Considering only fuel and variable O&M, these plants produce power for about $20-42/MWh when the price of natural gas ranges from $2.5-5/MMBtu as shown below.

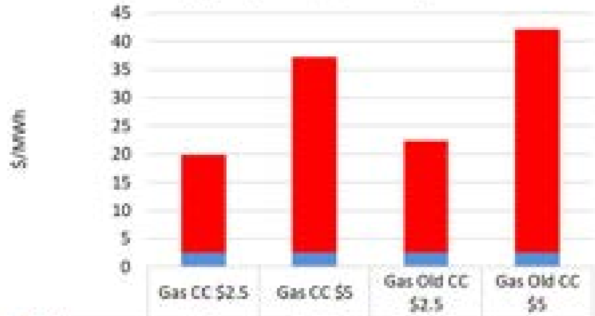
ISO-NE forecasts that existing gas combined cycle plants, except for the Mystic Station that is scheduled for retirement, will be needed to maintain overall regional system adequacy and reliability through 2030. New wind and solar generation will not replace any existing combined cycle plants that are still needed to meet summer peak loads. Beyond 2030, more gas generation will be required to support electrification of buildings and transportation.

Fixed operating costs, by definition, are incurred on an annual basis and are not related to plant output. Therefore, as these plants operate less hours per year, fixed operating costs have to be recovered through less output, or through higher prices for capacity payments and ancillary services. When fixed O&M costs are shown on a per MWh basis, they will vary based on estimated output per year.

Determining the future economic viability of gas combined cycle plants as their utilization is reduced becomes important if retirements are likely leading to a shortage of reliable capacity. This is an important issue in evaluating future regional planning needs.

Savings from the reduced operation of existing gas combined cycle units are evaluated in an hourly production model. The value of energy replaced by new wind and solar generation is estimated based on the fuel cost and variable operating costs for gas generation as shown in Figure 30.

Figure 30 Production Cost of Existing Gas Combined Cycle Plants



	Gas CC $2.5	Gas CC $5	Gas Old CC $2.5	Gas Old CC $5
Fuel	17.3	34.7	19.8	39.6
Variable O&M	2.5	2.5	2.5	2.5

As shown in Figure 30, the avoided cost from reducing gas combined cycle plant operation ranges from about $20-42/MWh based on fuel prices ranging from $2.5-$5/MMBtu. These values are in 2021 dollars assuming no real cost growth.

Cost estimates, performance calculations and power production costs are developed for all major New England power technologies using the CACI New England Technology Model, a simplified spreadsheet life cycle economic model. It works together with the CACI New England Market Model which provides hourly production cost calculations to determine the utilization of each generation category and resulting CO2 emissions.

Ownership and financing for new plants

When a power plant is constructed or acquired by a new owner, there are financial commitments to repay loans or bonds, to provide power to group of customers, and/or to provide a return to investors. Owners consider various risks of construction, operation, and market participation to establishing expectations regarding return on investment. Different forms of ownership distribute these risks in ways that change the effective cost of capital investment recovery.

Ownership and financing assumptions have a first order impact on the levelized cost of capital recovery. A number of economic assumptions are selected as the basis for this comparison to represent public, private, regulated and foreign export financing for new projects.

These ownership options represent a range of planning horizons (period of time that future expenditures dominate decisions). The planning horizon impacts how plants are designed, built, operated and retired using economic optimization. An indicative planning horizon is shown for various ownership/financing categories based on the number of years in the future that the value of a current investment drops by 75%. This value is roughly indicative of how long into the future planners and investors consider important when making financial and asset management decisions related to each form of ownership.

As shown below in Table 3, many underlying economic assumptions can vary considerably for actual projects and investors/owners.

Table 3 Ownership Impacts on Capital Recovery

Ownership	Discount Rate	Construction Interest	Tax Rates (Fed + State)	Levelized Annual Cost of Capital*	Planning Horizon (years)**
Private	10%	6%	21%+8%	14.7%	15
Regulated	8%	0%***	21%+8%	12.4%	18
Public	3%	3%	0	6.7%	47
Foreign	1%	1%	21%+8%	5.7%	139

*Planning horizon is defined as the number of years that the present value of a $1 investment decreases to $.25 based on the discount rate.
**For offshore wind projects
***Assumes a regulated utility can recover capital through customer rates as the plant is constructed.

Capital costs

Capital costs in $/kW for several new plant designs with different ownership/financing assumptions are summarized in Figure 31 below. These are derived from EIA published estimates (U.S. Energy Information Administration, 2021) in 2020 dollars, adjusted to include typical project development costs, owners costs for site preparation and interconnections, and construction interest.
Ownership/financing assumption impacts construction interest, with regulated financing assumed to make construction progress payments to avoid construction interest.

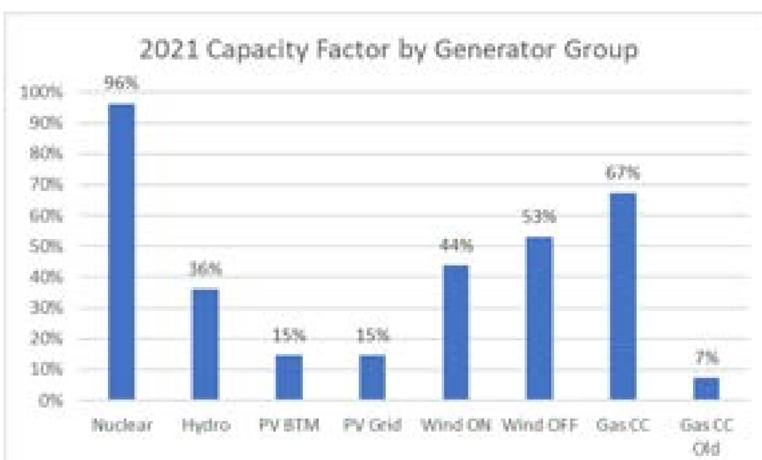
Figure 31 Total Financed Capital Cost for New Plants

CT = simple cycle combustion turbines; Reg = regulated utility financed; CC = combined cycle; SMR = small nuclear modular reactors; Pub = public power financed; Priv = private financing; Grid PV = grid-connected PV; BTM PV = behind the meter PV; BES = battery energy storage; OFFSW = offshore wind; Foreign = foreign export financing

Plant utilization

Higher plant utilization reduces the contribution of capital recover and fixed operating costs to total production costs per unit of electricity. The annual energy produced by a generator has a first order impact on production cost. The cost of capital recovery is fixed every year, so its contribution to production cost in $/MWh is the total annual cost of capital recovery divided by the number of MWh produced. Similarly, recovery of fixed operating costs increases per MWh produced with lower output. Capacity factor is the amount of energy produced per year divided by the theoretical amount that would be produced if the plant operates every hour at maximum capacity. The chart below compares the actual average capacity factor for each generator type based on 2019 data from ISO New England. Actual capacity factors for specific plants vary widely and are sensitive to how output capacity is measured. "Nameplate capacity" is normally used based on output at specific design conditions.

Figure 32 Average Utilization by Technology in 2021



Operating costs

Each type of plant incurs operating costs that must be recovered on an annual basis.

Fuel costs apply to fossil fired plants and wood fired plants that pay for fuel when it is consumed to produce electricity, normally expressed as $/MBTU (million BTU) of fuel heat content. The overall efficiency of a plant converting fuel to electricity is the plant heat rate expressed as BTU/kWh. Multiplied together these provide the plant fuel cost in $/MWh. Municipal solid waste (MSW) fired plants receive payments to take waste and incur penalties when they don't. Nuclear power plants periodically replace fuel on a fixed cycle (typically 18 months) during refueling outages that may not be scheduled to optimize fuel utilization. Wind and solar generating plants don't incur fuel costs. Battery storage plants have to pay for charging energy of which 15% is lost due to cycling inefficiency.

Variable operating costs occur only when a plant produces electricity and are typically expressed as $/MWh. They include consumables (such as water, chemicals, electricity, and some replacement parts), and the cost of inspections, repairs and replacements that accumulate over longer periods from wear and tear as the plant operates. The distinction between fixed and variable costs is not always clear and consistent given different budgeting and maintenance practices and can vary by how a plant is operated. Plants that start up and shut down frequently or operate at varying loads are likely to incur more wear and tear than those that operate continuously. Solar and wind generation have no variable costs according to most published studies and data, but there is growing experience with maintenance and the effects of disconnecting generators during surplus periods that may suggest reduced utilization has some variable cost effects.

A plant is dispatched, or bids into a competitive market, based on the determination of combined fuel and variable operating costs. If a privately owned plant cannot recover fuel and variable costs based on competing generation at a given time, it won't operate. Therefore, fuel and variable costs are only incurred and reimbursed when a plant operates. Some kinds of plants, such as combustion turbines, operate less efficiently and incur more maintenance when they operate at part loads or start and stop frequently in order to obtain payments for ancillary services to provide grid flexibility. Currently, combined cycle plants set wholesale prices most of the time based on their fuel and variable costs.

Fixed operating costs occur for all generating plants regardless of utilization. They typically include taxes, full time employees, contracted services, scheduled and unscheduled maintenance, permitting and regulatory requirements and setting aside money to support major future improvements and plant decommissioning. Fixed costs are recovered when a plant receives capacity payments, or when it receives payments from wholesale energy sales that exceed its fuel and variable costs.

A private plant owner must obtain sufficient annual income from competitive energy sales, capacity payments and payments for ancillary services to recover capital, operating and fuel costs. Otherwise, the plant will fail as a commercial enterprise and the plant will retire or need special subsidies to survive.

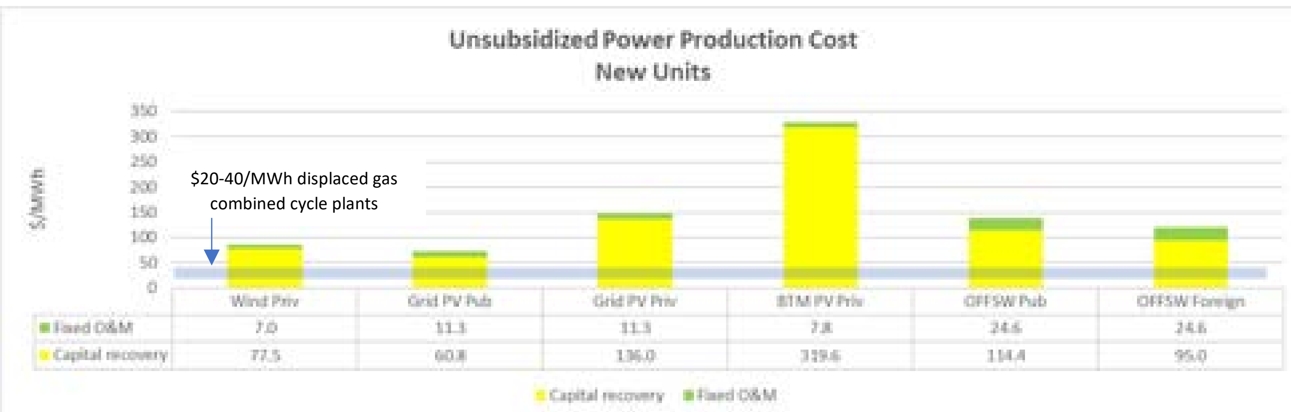
Production costs

Production cost expressed in $/MWh is calculated as the total annual costs for capital recovery, fuel and operating costs divided by annual electricity production.

Production costs for new solar, wind and battery storage facilities include capital cost recovery as well as fixed and variable operating costs based on assumptions provided by 2021 Energy Outlook (U.S. Energy Information Administration, 2021) and by other publications.

The range of production costs for operating existing gas combined cycle plants is shown below in Figure 33, including fuel costs and variable operating costs. Capital recovery, sensitive to ownership and financing assumptions, dominate these values.

Figure 33 Production Costs for New Generation



2020 dollars, various ownership financing assumptions; based on EIA Energy Outlook 2021 and other sources

Onshore wind

New privately financed onshore wind farms can produce power at about $85/MWh assuming excellent site and resource conditions. These production costs will increase as less desirable and more remote sites are developed with more expensive construction access, less attractive wind resources and more difficult grid interconnections. These unsubsidized costs are higher than wholesale power prices ($20-42/MWh) set by gas combined cycle plants. Subsidies for these projects are provided through tax credits, accelerated depreciation, state clean energy credits, and some transmission costs assigned to regional tariffs.

Grid connected PV

Privately financed grid-connected photovoltaic (PV) systems produce power at unsubsidized costs of about $147/MWh, much higher than wholesale prices set by gas generation. Publicly financed installations costs drop to $72/MWh because of lower capital recovery costs using municipal bonds. These projects are subsidized by tax benefits, state clean energy credits and a variety of other incentives including net metering and offtake agreements.

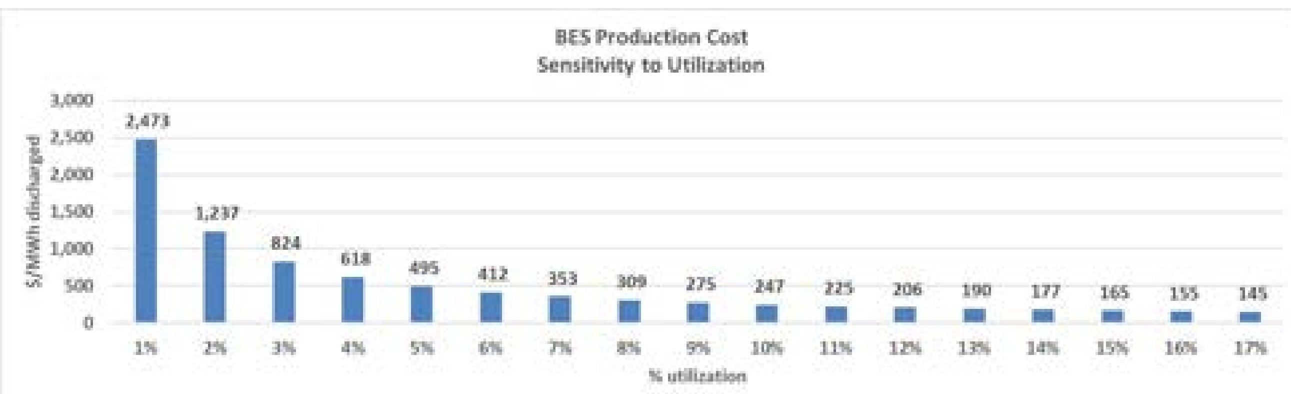
Behind the meter PV

Privately financed behind the meter (BTM) PV systems, such as rooftop solar installations, have unsubsidized power production costs at over $300/MWh which vary with different sizes, locations and orientations. They are supported primarily by tax incentives, by special state clean energy credits much higher than for other technologies, and by net metering. It is important to note that major improvements to electrical distribution systems are underway to accommodate two way flow of distribution power and other requirements, which are recovered in part through interconnection fees charged to each project.

Battery energy storage

Battery energy storage systems (BES) are currently being installed by regulated distribution utilities, mandated by state regulators and allowed to be included in their rate base charged to electric customers. BESS unsubsidized production cost, not including the cost of charging energy, is about $150/MWh when fully utilized through a single 4-hour charging cycle every day, with a capacity factor of 16.67%. The biggest uncertainty in calculating BESS production cost is utilization. As shown in Figure 34, lower utilization requires higher recovery of fixed operating costs and capital per MWh produced. The chart below in Figure 34 is based on 2020 dollars and private ownership. These costs do not include the cost of charging energy and discharging cycle losses.

Figure 34 Battery Storage Production Cost by Utilization



The utilization of installed BESS is determined by hourly modeling restricting utilization to the recovery of surplus solar or wind energy to reduce CO2 emissions. The additional costs for using BESS to recover surplus solar and wind generation are assigned primarily through rates charged by electric distribution companies.

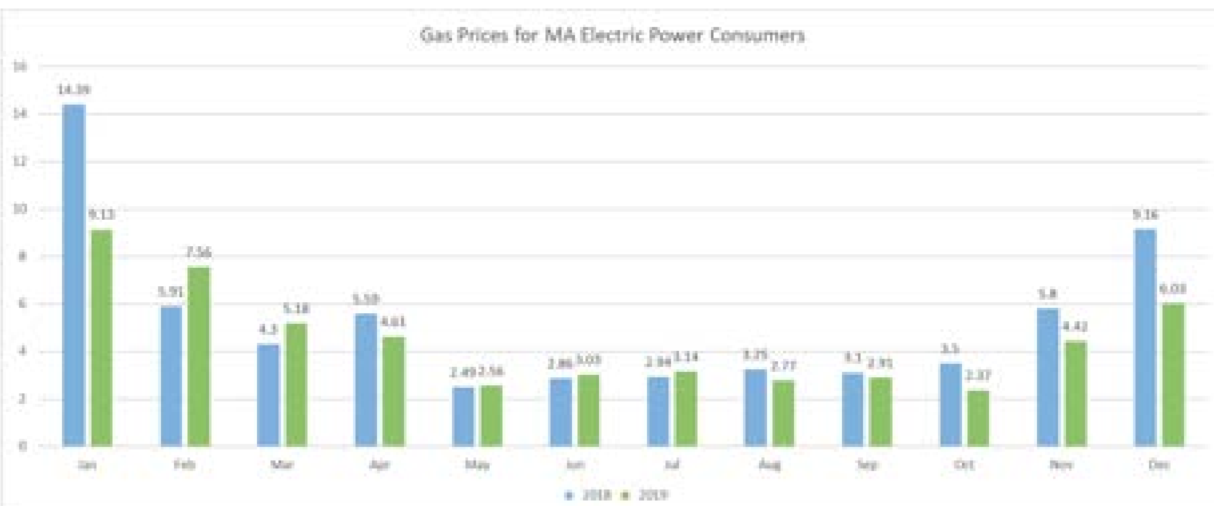
Offshore wind

Offshore wind projects represent the largest projected growth of regional power generation. Projected unsubsidized costs are about $120/MWh assuming very inexpensive capital is provided by foreign export financing. These costs are very sensitive to transmission grid connection costs and ownership financing effects, as well as resource variability and offshore equipment reliability assumptions. The higher costs of these projects are covered by various tax incentives, state clean energy credits, sharing of transmission interconnection costs, and state mandated offtake agreements with distribution companies that purchase electricity at above-market prices.

4.5. Natural gas pricing

Until recently, natural gas prices have been low for several years reacting primarily to the costs of production and pipeline delivery. Higher demand during cold winter months pushes prices up, while prices during months with high solar production have been lowest, as shown below in Figure 35. The DOE EIA publishes Massachusetts Natural Gas Price Sold to Electric Power Consumers (U.S. Energy Information Administration, 2021)

Figure 35 Recent Variability of Gas Prices



The chart above in Figure 35 shows reported gas prices sold to electric power generators provided by US IEA (US EIA, 2021). Some of the 2020 and 2021 data is withheld by EIA because it may disclose competitive information. A colder winter in 2018 resulted in higher prices during some winter months. International oil markets pushed up gas prices in 2021. High gas prices during a few winter periods represent a small fraction of total annual gas costs.

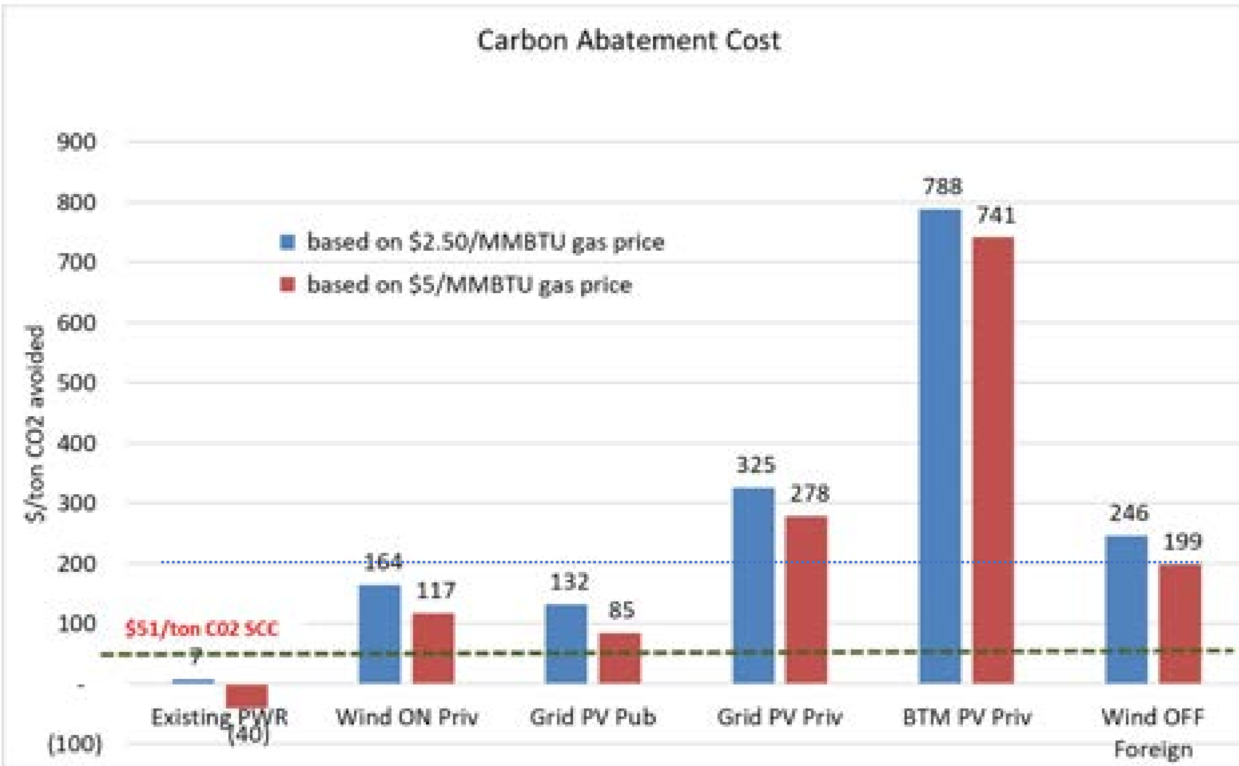
The cost of gas actually incurred for generation is a mix of contract pricing and spot pricing which is often confidential given competitive bidding into the wholesale market. When higher amounts of gas generation are needed during summer peak months, the use of higher spot pricing increases. When lower amounts of generation are needed, lower gas prices apply through longer term contracts and commitments for minimum utilization. Gas supply shortages in the winter result in a shift to the use of liquified natural gas (LNG) which causes a steep rise in pricing.

Given the difficulty in predicting future gas pricing, a range of gas prices from $2.50/MMBTU to $5/MMBTU is used. It is important to recognize that increasing solar generation is likely to displace gas generation during periods when gas prices are lowest.

4.6. Carbon abatement costs by technology

Carbon abatement costs measure how much it costs for a new power generating project to avoid one ton of CO2 emission. As discussed above, they are calculated as the required subsidy divided by the amount of CO2 avoided. Estimated carbon abatement costs are shown below in Figure 36 for several decarbonization options and for two gas prices. Results are sensitive to economic, technology and performance assumptions.

Figure 36 Carbon Abatement Cost by Technology and Fuel Cost



PWR - pressurized water reactor (Seabrook, Millstone); SMR - small modular reactor; BES - battery energy storage; BTM - behind the meter PV; Foreign - foreign financed; Pub - public power financed; Priv – privately financed; OFFSW - offshore wind

These carbon abatement costs are calculated based on comparing current fuel and variable operating costs for existing gas combined cycle plants with production costs for new plants in 2020 dollars.

Extending the life of existing nuclear plants

The carbon abatement cost for extending the life of existing nuclear units (Seabrook and Millstone) is based on their estimated fuel and operating costs, and for recovery of a nominal $500 million capital investment to support operating license extension. Nuclear fuel costs are assumed to be $4.1/MWh. These are compared to the fuel and variable costs of gas combined cycle plants. Extending the operations of these units results in a carbon abatement cost ranging from $7/ton CO2 to -40/ton CO2 for $5 and $2.50 gas prices, respectively. At higher gas prices no subsidies are needed unless major additional investments are required for life extension.

Adding advanced nuclear plants

No new nuclear generating projects are planned for the next decade in New England, but the technology may become available during that period. A new nuclear SMR (small modular reactor) generation case assuming public power ownership is included to illustrate the potential economics of this option. Based on EIA cost projections in 2021 Energy Outlook, the carbon abatement cost for new small modular reactors (SMR) ranges from $53/ton for $5 gas to $100/ton for $2.5 gas, based on projected cost targets for fully commercialized technologies. Cost assumptions are based on current targets for commercial SMR plants which may not be representative of early projects. Based on these assumptions, future new advanced nuclear projects in New England could provide reductions in CO2 emissions at lower cost than planned solar and wind installations.

Adding onshore wind generation

New onshore wind generation could double existing capacity by 2030. Applying cost assumptions for new onshore wind farms provides a carbon abatement cost of $117-164/ton CO2. Subsidies are currently provided by a combination tax benefits, clean energy credits, coverage of some transmission improvements through tariffs, and other forms of support.

The cost of wind turbine generators has decreased with improvements in technology, larger wind turbines, and increased production. However, new proposed sites tend to be further from major transmission and will incur higher interconnection costs. Also, public acceptance of onshore wind installations with their significant construction footprint, and the need for construction of new transmission rights of way can increase uncertainty in project costs.

Adding grid connected PV

Solar farms (grid connected PV) financed by municipalities or private developers are projected to double in capacity this decade. Carbon abatement costs range from $85-132/ton for publicly financed projects and $278-325/ton for private financing for $2.5-5 gas, respectively. Current subsidies include tax benefits, net metering, clean energy credits and above market power sales contracts.

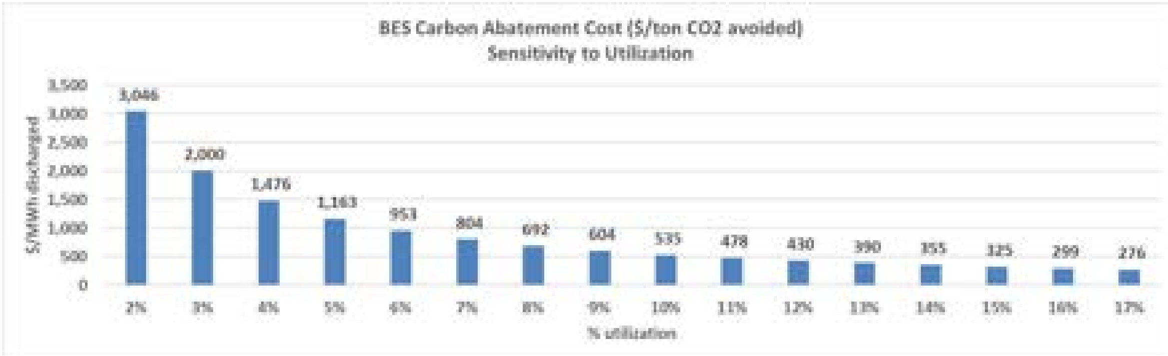
Adding BTM PV

Privately financed behind the meter (BTM) PV systems are the most expensive option for reducing CO2 at $741-788/ton for $2.5-5 gas, respectively. Additional costs are required to modify some distribution systems to allow two-way flow of power, which can be charged as interconnection fees. Current subsidies include higher solar clean energy credits, tax incentives and net metering. Distribution system improvements are recovered by regulated utilities through project interconnection fees and customer distribution costs.

Adding battery energy storage

Carbon abatement cost for battery energy storage (BESS) systems shown below in Figure 37 are based on discharge energy assuming an average round trip efficiency of 85% and assumes that charging energy is all from surplus carbon free sources which would otherwise be discarded. This value does not include the cost of charging energy, the potential transfer of subsidies through negative pricing, or the cost energy lost in discharging cycle.

Figure 37 BES Carbon Abatement Cost by Utilization



Battery storage utilization to reduce CO2 emissions is determined by hourly modeling in subsequent sections, and is limited roughly 5-12% resulting in very high carbon abatement costs.

5. Social Cost of Carbon

Subsidies for wind and solar generation are justified by the expectation that reducing human caused carbon emissions will reduce harmful effects of climate change in the future. Carbon abatement costs are calculated as $/ton CO2 avoided. Evaluating the effectiveness of decarbonization investments should consider the value of a ton of CO2 that is avoided by new generation. The value concept of reducing one ton of CO2 also represents the cost of not implementing decarbonization projects, and can be considered as an equivalent universal carbon tax that could replace all other climate related subsidies. When expenditures to reduce carbon emissions exceed the estimated value of these reductions, the cost-effectiveness of energy policy can be questioned.

The Social Cost of Carbon (SCC) has been calculated by the US General Accounting Office (GAO, 2020) and others as the present value of future additional costs resulting from climate change impacts. SCC represents the estimated cost to society of not reducing CO2 emissions, based on an extensive, complex and controversial analyses relying on a number of scientific interpretations and economic assumptions.

The GAO report summarizes the need to monetize the effects of greenhouse gas emissions:

> *"In examining possible approaches to address these emissions, some countries are weighing the potential costs of taking actions to reduce emissions against their expected benefits by including monetary estimates of the effects of carbon dioxide and other greenhouse gas emissions in cost-benefit analyses. Developing these monetary estimates and using them to assess the costs and benefits of taking government actions to reduce greenhouse gas emissions involves a complex mix of economic analysis, climate modeling, and science."*

Calculation of SCC considers this complex mix of considerations using computer modeling (Resources for the Future, 2021) (Kingdon, 2019) Future CO2 emissions are predicted based on population, economic growth, and other factors. Then future climate responses, such as temperature increase and sea level rise are modeled. Then economic impacts on agriculture, health, energy use, and other aspects of the economy are calculated. Future damages are converted into their present-day value and added to determine total damages. A baseline value for the damages of emissions is determined and then the costs of incremental emissions are evaluated to estimate the SCC and uncertainties.

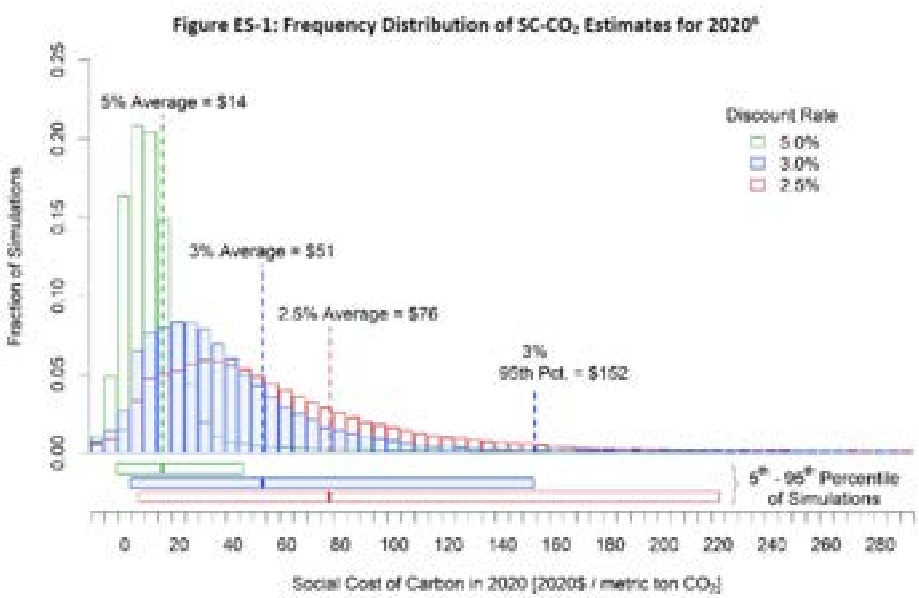
The concept of an SCC is fundamental to evaluating the effectiveness of energy policy that requires investment in expensive technologies with the objective of reducing CO2 emissions.

President Biden has ordered his administration (The White House, 2021) to undertake a rigorous examination of SCC for consideration in the administration's climate initiatives.

The Biden administration interim estimates of SCC are published in a report issued in February 2021, entitled "Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide, Interim Estimates under Executive Order 13990" (Interagency Working Group on Social Cost of Greenhouse Gases, 2021). SCC estimates from this report are summarized in Figure 38 below. A note in this report summarizes the requirement to assess the cost and benefits of new regulations as follows:

Under E.O. 12866, agencies are required, to the extent permitted by law and where applicable, "to assess both the costs and the benefits of the intended regulation and, recognizing that some costs and benefits are difficult to quantify, propose or adopt a regulation only upon a reasoned determination that the benefits of the intended regulation justify its costs."

Figure 38 Social Cost of Carbon Analysis



The average value of \$51/ton CO2 (3% discount factor) shown in Figure 38is currently suggested as a policy guide by the Biden administration, recognizing that additional work is underway to apply more recent information and techniques and to address challenges to the assumptions and process.

Applying that rate to 33 million tons of CO2 emissions (36 million metric tons) from power generation in New England represents an annual cost of about \$1.9 billion/year.

Agreement on a SCC value as a policy guide requires an extensive discussion and careful review of scientific interpretations, economic assumptions, and underlying uncertainties. SCC should consider the effectiveness of proposed policies in the context of global initiatives, participation and effectiveness. The SCC set as the basis for energy policy may be zero if it is determined that global participation in decarbonization is unlikely to happen, or that major uncertainties exist in the ability to tie climate change impacts to human emissions. (Koonin, 2021)

New England states participate in the Regional Greenhouse Gas (RGGI) (RGGI, Inc., 2021) which implements a cap-and-trade program through the sale of emission allowances. A recent quarterly auction in June 2021 set a clearing price of $7.97 per short ton of CO2 and generated $183,212,120 for states to reinvest in strategic programs, including energy efficiency, renewable energy, direct bill assistance, and GHG abatement programs. Allowance prices are capped at $13 per ton in 2021.

The SCC set a policy directive is the key to setting limits to decarbonization investments and as a base metric in evaluating the cost effectiveness of decarbonization investments.

6. Projected Changes in Generation and Grid Behavior

Evaluating technical and economic limits to the integration of new wind and solar generation requires an understanding of how behavior of the New England power grid will change. Hourly modeling of the New England power grid determines how existing plants contribute to CO2 emissions and how their operation, economics and emissions will change with the addition of new solar, wind and battery generation.

Combined cycle gas fired plants are targeted as the primary source of CO2 emissions in New England but provide grid flexibility and reliable capacity to serve peak loads. Current state climate initiatives target doubling existing solar and wind generation, plus launching large scale development of offshore wind generation

Large-scale installation of new battery storage capacity will reduce the amount of energy wasted from surpluses of wind and solar generation but is poorly utilized because of the limits of 24 hour charging cycles and the timing of surpluses and gas generation.

Hourly economic dispatch of each generation type is modeled to address system loads adjusted for regional power purchases and sales. Hourly CO2 emissions, wholesale energy pricing, and the occurrence of surplus energy from excessive non-dispatchable generation are calculated.

6.1. Modeling hourly grid behavior

Modeling current hourly behavior of the New England power grid shows important relationships and behavior related to the variability of system load, exchanges of power with New York and Canada, output from behind-the-meter (BTM) generation, and the interaction of different groups of generators.

Hourly calculations of grid behavior are provided using the CACI New England Market Model. Inputs include historic data for loads, solar generation, wind generation, hydro generation, and power exchange with other regions. Transparent assumptions and calculations use simple spreadsheet techniques to determine hourly loads, generation, regional exchanges, wholesale market price, fuel consumption, CO2 emissions, and earnings by generation category. This hourly production cost model and supporting documentation will be made available through CACI (www.centeraci.com) to support teaching and additional research and studies.

The assumptions and methods used in this model are summarized below.

Generating facilities

Power generation capability is represented into simplified categories:

- behind the meter (BTM) solar
- grid-connected solar

- onshore and offshore wind
- hydroelectric
- nuclear
- gas generation divided into new and older gas combined cycle plants and simple cycle combustion turbines
- older steam boiler units firing gas, oil and coal
- other generation (wood, municipal waste and landfill gas)

Existing nameplate capacities are published by ISO-NE, while actual maximum output on a regional basis is determined based on 2019 data. Variations in output due to resource, weather, scheduled outages, and other factors are also represented based on available 2019 historic data.

Loads

Total system loads are estimated from published ISO-NE data for 2019. They are adjusted to include estimates of BTM solar generation. 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 ISO-NE.

Regional purchases and sales

Purchases from Canada are modeled based on 2019 actual hourly data, using representative hourly variations for each month. Purchases from Canada are assumed to be from hydroelectric power plants with no CO_2 emissions. Additional capacity is assumed to be added in 2025 with the projected completion of new transmission capacity.

Power exchanged with New York is estimated using representative hourly variations in each month based on 2019 actual data.

Solar and wind generation

Hourly generation from grid-connected solar and from BTM solar is calculated based on 2019 hourly data representing total regional solar power output. Existing and projected installed solar nameplate capacity is based on ISO-NE planning documents. Maximum output from solar generation is estimated by matching actual annual generation using hourly variations.

Hourly generation from onshore and offshore wind is calculated based on 2019 hourly data provided by ISO-NE. Maximum regional output each year from onshore and offshore wind generation is estimated by adjusting nameplate ratings based on hourly variations and total annual output.

Dispatch

Hourly loads are determined for each day of the year. Each resource is dispatched to reduce load as follows:

- BTM solar is deducted to represent the load served by the grid.
- Purchases from Canada are deducted.
- Nuclear plant output is deducted as “must-run” capacity.
- Hydroelectric generation is deducted.
- Output from other (wood, MSW and landfill gas) is deducted
- Output from grid connected solar, onshore and offshore wind generation are deducted based on hourly variations.
- Purchases from or sales to New York are included.
- The remaining load is addressed by gas fired generation in order of efficiency, starting with new gas combined cycle plants, older gas combined cycle plants, newer gas combustion turbines, older gas combustion turbines, then older steam units.

Minimum flexible generation

3% of maximum annual load is set aside for system control by gas combined cycle plants or battery energy storage discharge, representing spinning reserve and other ancillary services. This is required even when there are curtailments of solar and wind generation.

Curtailments

Curtailments occur when total inflexible generation exceeds load requirements. When there is insufficient load left to use total solar and wind generation, purchases from New York are reduced or eliminated. Then curtailments are assigned first to offshore wind, onshore wind, grid-connected solar, and BTM solar.

Wholesale price

The wholesale price is set each hour by the last category of generation needed, based on the fuel and variable cost for that category. When there are no curtailments, prices are set by gas plants. When there are curtailments, prices are set by negative bidding from solar and wind generators based on very preliminary assumptions regarding a combination of a region-wide clean energy credit and representative nominal variable costs for each technology set to differentiate their curtailment order. Normally, wind and solar generation is characterized by zero variable costs.

CO2 emissions

CO2 emissions are calculated each hour from each emitting generation type including gas combined cycles, gas combustion turbines, power purchased from New York (assumed to be gas combined cycles), and other generation (composite of wood, MSW and landfill gas.)

Modeling assumptions and limitations

Several simplifying techniques and assumptions facilitate the evaluation of hourly dispatch, pricing and CO2 emissions:

- Nuclear units are assumed to experience an average refueling outage every year, rather than modeling an 18-month refueling cycle.
- Oil and coal firing is ignored since this occurs very infrequently with very small CO2 emissions.
- 2019 hourly load and generation behavior is assumed to avoid Covid-related anomalies which have changed loads in the last few years.
- Canada purchases are assumed to follow the same daily and hourly patterns from 2019 data, adjusted for annual changes in import capacity.
- Hydroelectric output includes a composite of pumped storage and other installations since hourly data is not available to separate them. Pumped storage hourly behavior embedded in this data, is responsive to typical daily load variations.
- The cumulative regional behavior of offshore wind generation is assumed to result in a reduced maximum output similar to onshore wind generation output reported for 2019.
- Other generation (wood, MSW and landfill gas) are not targeted for CO2 reduction and operate as must run capacity.

6.2. Changing loads

Hourly load patterns are modeled based on 2019 data available from ISO-NE. Loads vary based on consumer behavior such as going to work and operating appliances, ambient temperature which drives building heating and cooling, daylight which drives lighting, as well as commercial and industrial activity. Hourly load shapes are selected for workdays and for non-work holiday/weekend days and adjusted weekly for seasonal changes.

ISO-NE now reports estimated generation from BTM solar as part of the total system load, even though it occurs on the customer side of the grid. BTM solar currently represents the majority of regional solar electric generation capacity.

Regional system loads are changing annually as energy use changes based on many factors. Plans to implement state driven energy efficiency programs will reduce loads, while electrification of heating loads will increase winter loads and electrification of transportation will increase year-round loads. Peak summer and winter loads will increase substantially if electrification policies are successfully implemented.

According to ISO-NE's draft Regional System Plan for 2021 (ISO-NE, 2021),

- *"The 10-year net energy for load, accounting for EE, PV, and electrification, is projected to increase from 121,692 gigawatt-hours (GWh) in 2021 to 133,960 GWh in 2030, which represents an increase of 1.1% per year. The "50/50" net summer peak forecast is 24,810* *megawatts (MW) for 2021, and remains steady at 24,796 MW for 2030. The "90/10" net summer peak forecast, which represents demand during a hotter summer heat wave, is 26,711 MW for 2021 and increases slightly to 26,816 MW in 2030.*

- *The gross winter peak demand from 2021 through 2030 grows at 1.3% per year, with expected demand savings from EE reducing annual peak demand growth to 0.8% per year. Much of the growth reflected in the winter demand forecast is a result of electrification initiatives throughout the region.*

- *The impacts of strategic electrification across the region, including consumer adoption of electrified light-duty vehicles and residential air-sourced heat pumps, are expected to add 6,080 GWh of annual energy, 675 MW of summer demand, and 2,422 MW of winter demand by 2030."*

Figure 39 shows ISO-NE's historic and forecasted summer and winter peak loads. Winter peak loads are projected to rise faster than summer peaks due to projected electrification of building heating systems to reduce the use of natural gas.

Figure 39 Historic and Forecasted Summer/Winter Seasonal Net Peak Demand

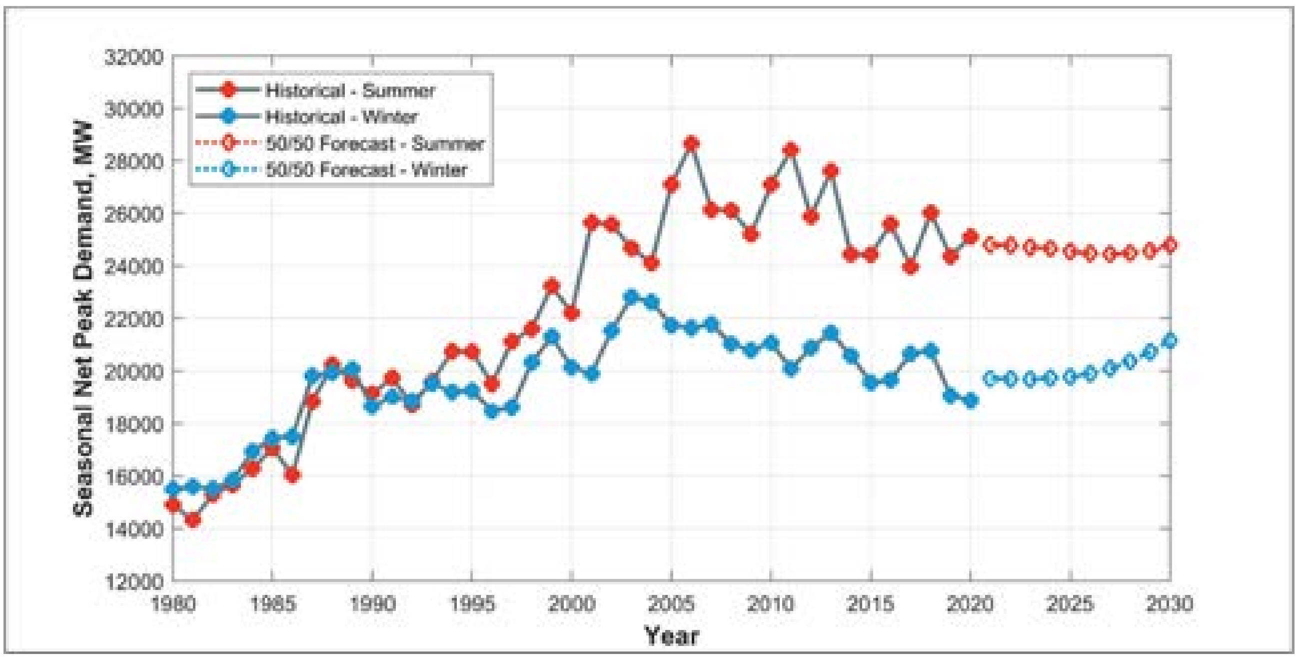
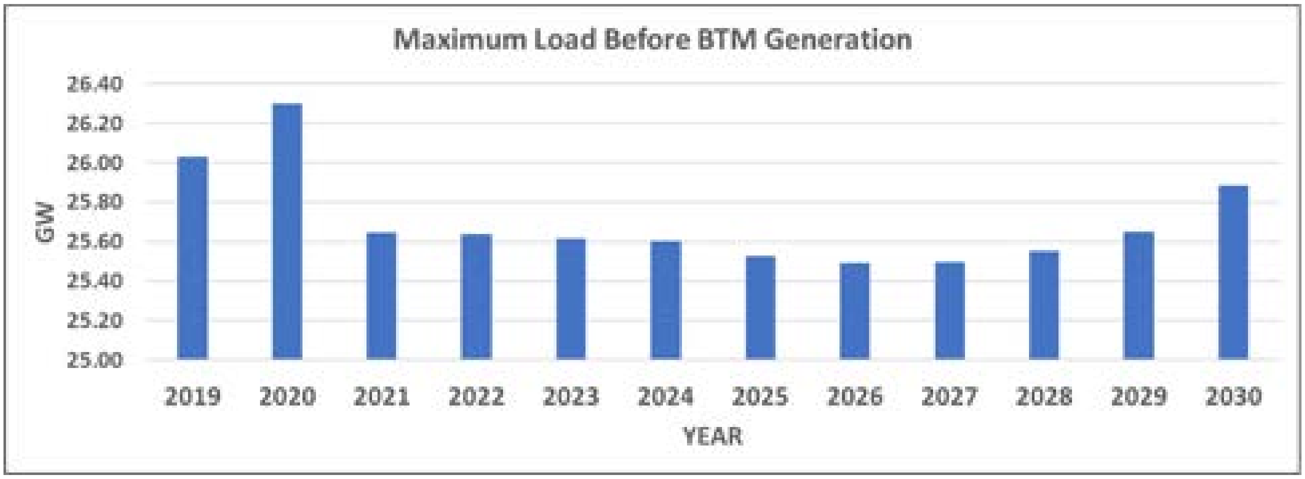


Figure 40 shows the maximum annual load as projected by ISO-NE. BTM solar generation is not included but does not significantly impact peak loads, which occur in the evenings. Maximum load declines slightly through 2027 and then rises as electrification programs have growing impact. These maximum loads are used to model hourly generation each year.

Figure 40 Projected Load Growth Including BTM Generation

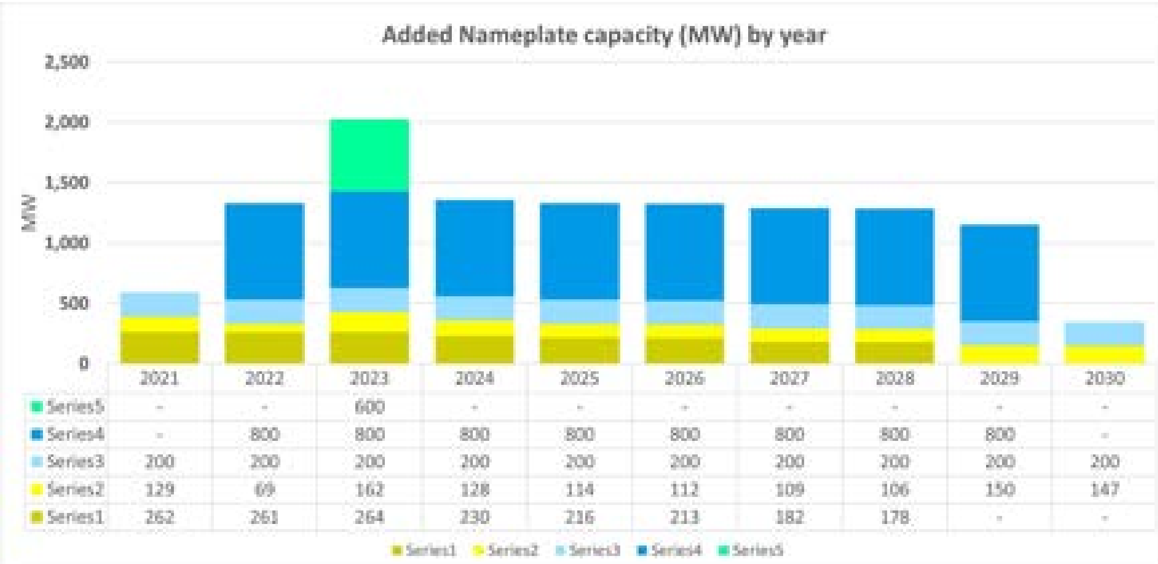


ISO-NE projects that state energy efficiency (EE) programs, which reduce building lighting, heating and cooling electrical energy consumption, will reduce capacity requirements by 1515 MW between 2020 and 2030. The effect of these EE investments through 2030 is included in ISO-NE 2030 load projections.

6.3. Changes in generation capacity

All projected capacity added through 2030 is driven by state subsidies that specifically support the installation of wind, solar and battery systems with the intent of reducing CO2 emissions from gas fired generation. No significant additions of gas fired, or other types of generation driven by market conditions without subsidies are currently projected by ISO-NE. Figure 41 below shows the annual capacity additions assumed for the analysis of decarbonization costs and effectiveness in this report.

Figure 41 Yearly Capacity Additions



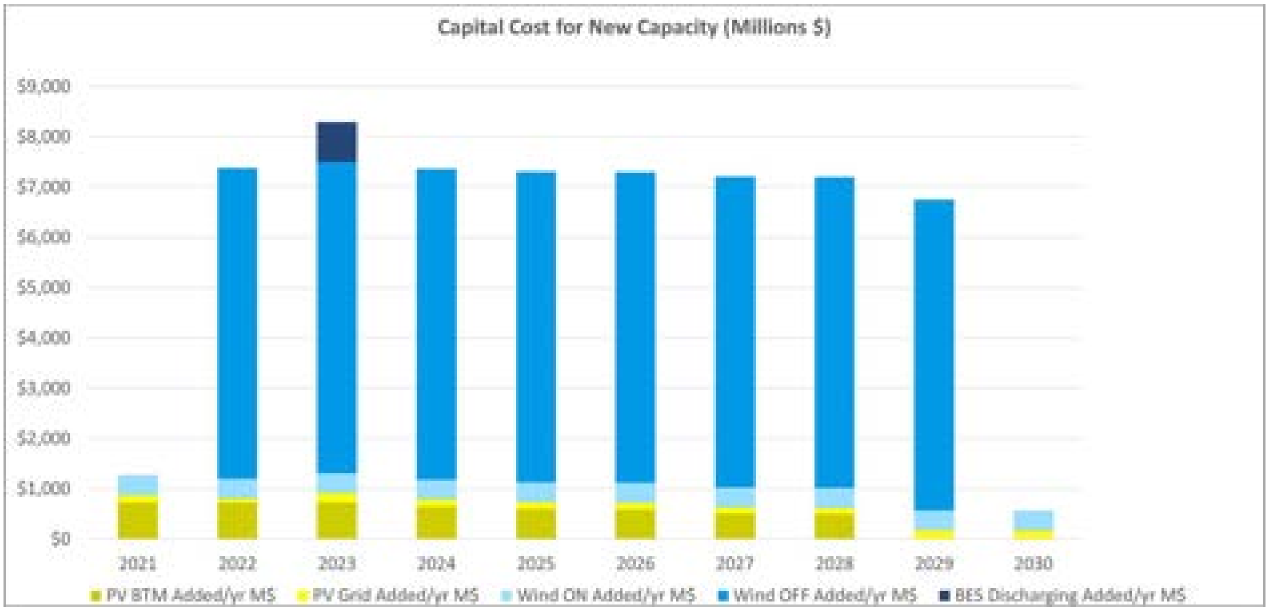
These projected capacity additions are consistent with state policy announcements that collectively indicate a goal of roughly doubling existing solar and wind generation, and rapidly expanding offshore wind installations.

The 2021 ISO-NE CELT report (ISO-NE, 2021) provides projections for new BTM PV, grid connected PV systems and battery energy storage based on analysis of federal and state policy announcements offering tax incentives, clean energy credits, net metering and mandated procurements.

19,705 MW of new wind generation projects in New England have applied for interconnections, but only some of this is likely to be installed. ISO NE estimates that roughly 6000 MW of new regional offshore wind capacity has the potential to be connected without the need for major transmission reinforcements. For purposes of the analysis presented in this report, it is assumed that 200 MW of onshore wind are added each year, and that 800 MW of offshore wind is added each year for eight years beginning 2022.

Capital investments for these additions are shown below in Figure 42.

Figure 42 Capital Investments for New Capacity



The capacity additions shown in Figure 41 Yearly Capacity Additions

represent an investment of roughly $61 billion, by applying capital cost estimates derived from the US EIA 2021 Energy Outlook (U.S. Energy Information Administration, 2021) and other sources, as summarized in Table 4 below. Note costs are in 2020$ and do not include inflation.

These estimates are updated annually by EIA. These estimates include the cost of grid interconnection but exclude transmission and distribution improvements needed to support large scale development of these installations.

Table 4 Projected Total Investments in Wind and Solar Generation 2022-2030

Technology	Capacity (GW)	Capital cost ($/kW)	Investment ($billions)
BTM Solar	1.5	2,770	4.3
Grid Solar	1.1	1,156	1.3
Onshore Wind	1.3	1,981	3.6
Offshore Wind	6.4	7,393	49.5
Battery Storage	0.6	1,329	0.8

Installed capacity is shown in terms of the design, or “nameplate” output rating. Capital investments are shown as $/kW in 2020$ based on nameplate capacity. These estimates are consistent with Figure 31 Total Financed Capital Cost for New Plants on page 4-4-7.

3,450 MW of nameplate hydroelectric capacity currently produces a maximum of 2,776 MW during the year and is projected to remain in service through 2030. However, declining revenue from energy surpluses may reduce the ability of some of the older hydro units to make the investments necessary to extend their safety analyses and operating licenses potentially leading to some retirements and less capacity than projected. No such retirements are assumed for this analysis.

The 1.7 GW Mystic Station which operates on LNG is scheduled for retirement in 2023, ISO-NE projects that existing gas combined cycle plants, combustion turbines and steam plants will need to stay in service to provide reliable capacity during peak periods, extreme weather and emergencies. Some of these units can operate on oil when gas become unavailable during the coldest winter days. Gas combined cycle plants will operate less as solar and wind generation increases and will rely increasingly on capacity payments to stay in service.

The three operating nuclear units at Millstone and Seabrook are assumed to stay in service through 2030.

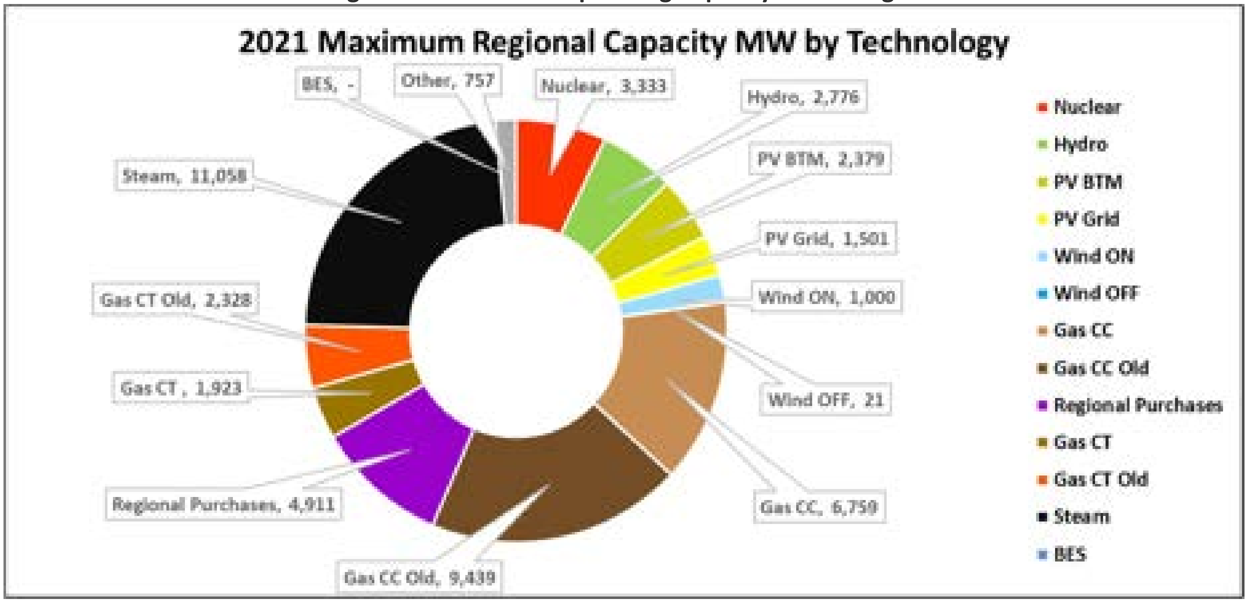
6.4. Changes in energy output

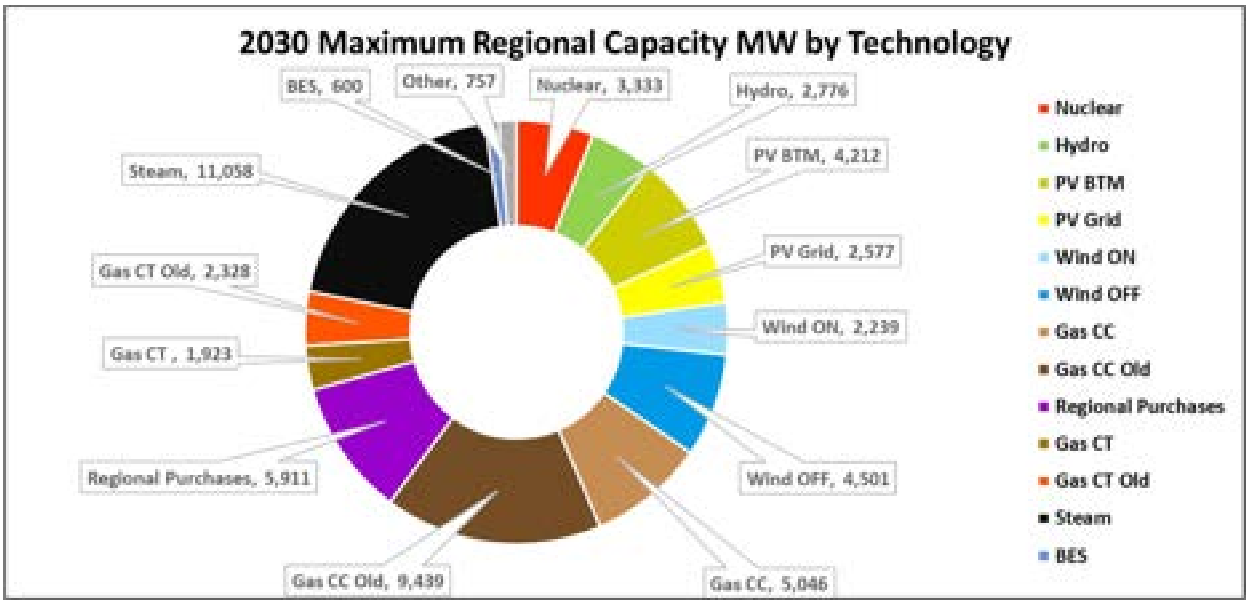
Hourly dispatch of each generation type is modeled based on historic load patterns and changing installed capacity. The output from gas fired units varies with ambient temperature and outages. The maximum amount of power that can be produced by solar and wind generation is much lower than total nameplate ratings because of regional distribution and resource variations.

Maximum outputs from each generator group are estimated by modeling hourly output to match 2019 actual generating data. For this analysis, offshore wind is assumed to have the same relationship of maximum regional output to nameplate capacity as onshore wind, pending availability of actual regional operating data for offshore wind installations.

The changes in maximum output by technology in 2021 and in 2030 are compared in Figure 43 below.

Figure 43 Maximum Operating Capacity Mix Changes

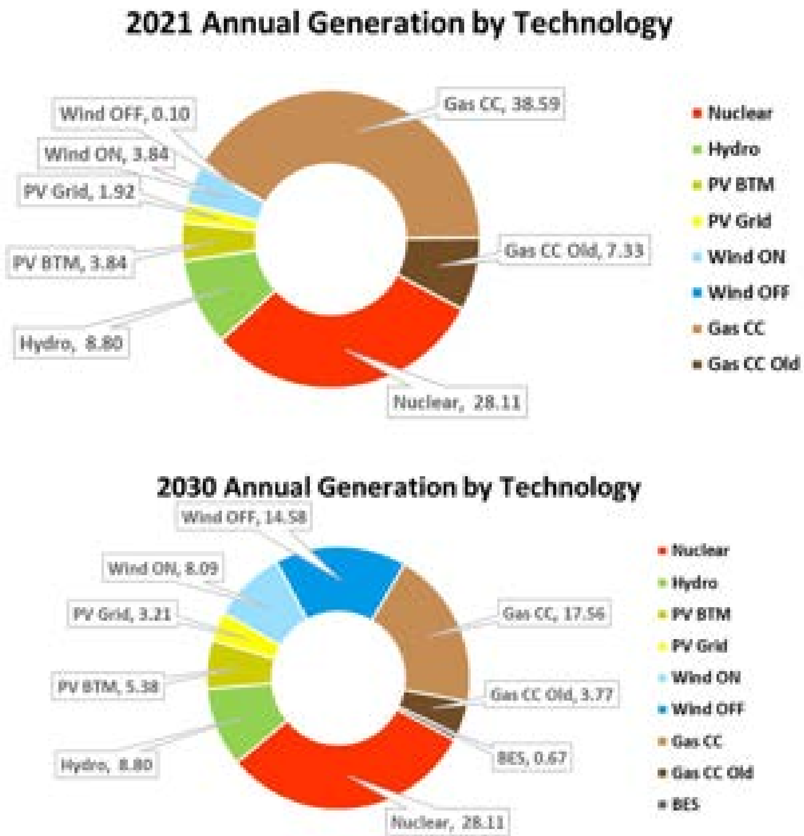




As shown above in Figure 43 the major changes in maximum operating capacity represent a doubling of solar and onshore wind, and a large increase in offshore wind capacity. 600 MW of BESS is added. Maximum regional capacity of solar and wind generation is an estimate of their highest combined output in the region at any one time.

Figure 44 below compares annual generation by technology in TWh (terawatt-hours, or thousands of MWh) for 2021 and 2030.

Figure 44 Energy Mix Changes



As shown above in Figure 44, nuclear generation is constant representing continued operation of the reactors at Millstone (CT) and Seabrook (NH). Refueling outages occur every 18 months for each unit and are likely to be scheduled during spring months when solar output is high and loads are low. For this analysis, nuclear outages are averaged over the years. It is possible, based on growing energy surpluses and negative wholesale pricing, that nuclear units will extend their outages and contribute less energy annually than assumed for this analysis.

2030 projected energy generated from wind and solar are reduced due to surpluses and curtailments discussed in the next sections. Some of the surplus energy is recovered by BESS.

6.5. Regional power exchanges

New England buys and sells power based on 13 major interconnections with Canada and New York. The detailed capabilities for regional exchange of power are described by ISO-NE in its 2021 Regional System Plan (ISO-NE, 2021).

Modeling these exchanges employs several simplifying assumptions. Current and projected regional exchanges are modeled as a single NY connection and a single Canada connection based on data for the hourly exchanges that occurred in 2019. Purchases from Canada are assumed to be carbon-free, while purchases from NY are assumed to be from gas combined cycle plants. Purchases from Canada are assumed to be inflexible based on patterns of hourly purchases in 2019. Purchases and sales with NY are modeled based on 2019 hourly patterns, but are reduced when there are energy surpluses.

The effect of mandatory purchases from Canada of carbon free electricity is important when energy surpluses and curtailments occur. It makes no sense economically to replace imports of carbon free electricity from Canada with more expensive solar or wind generation, unless this would result in decreased fossil generation in Canada which has not been determined. Adding flexibility to these purchases could decrease curtailments of renewable energy production in New England but may not be consistent with current agreements. Modifying agreements with Canada to add flexibility to reduce regional surpluses of solar and wind energy is currently under study at ISO NE.

6.6. Changes in daily energy production

It is important to understand the effect of timing constraints on solar and wind generation relative to when CO_2 is produced by gas combined cycle plants. Adding solar generation only addresses mid-day loads, highest in June and lowest in December based on resource variations. New wind generation can only statistically provide to 30-50% of possible rated output distributed over the day. Therefore, more than half of gas generation that occurs late in the day during and after peak loads cannot be effectively reduced by wind or solar generation.

Figure 45 illustrate the annual total generation by solar, wind and gas generation in 2021. Other generation which is not impacted by the addition of solar and wind generation is not included in order to clarify the displacement of gas by renewables. Very little solar and wind energy is curtailed.

Figure 45 2021 Solar, Wind and Gas Annual Generation by Hour

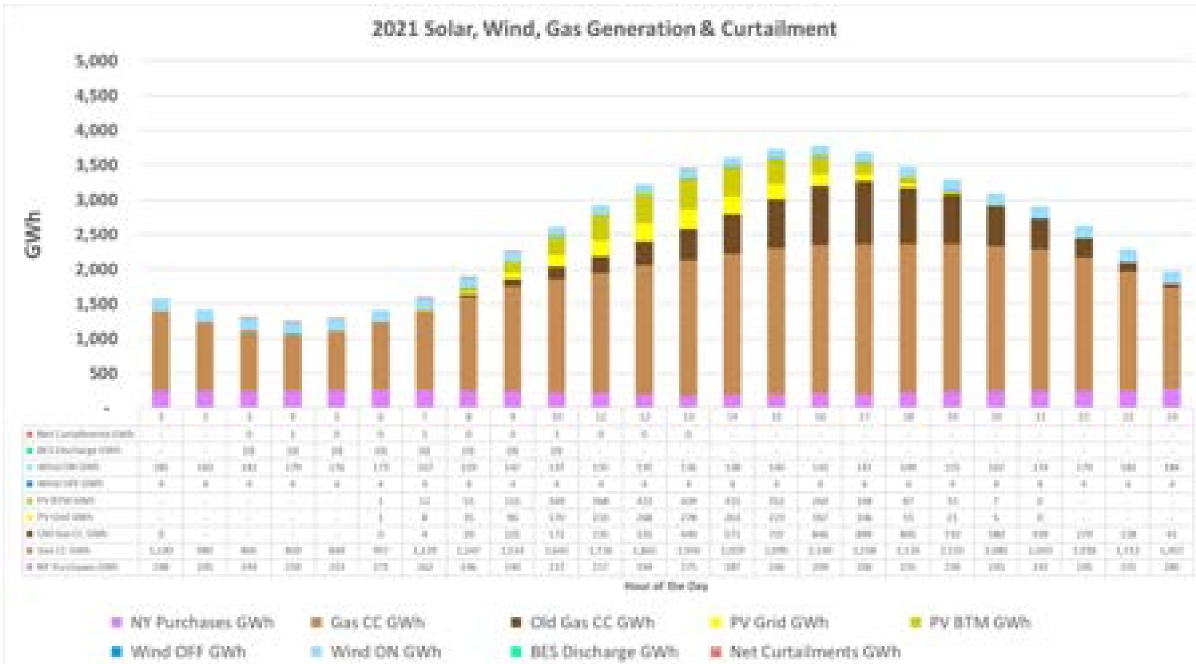
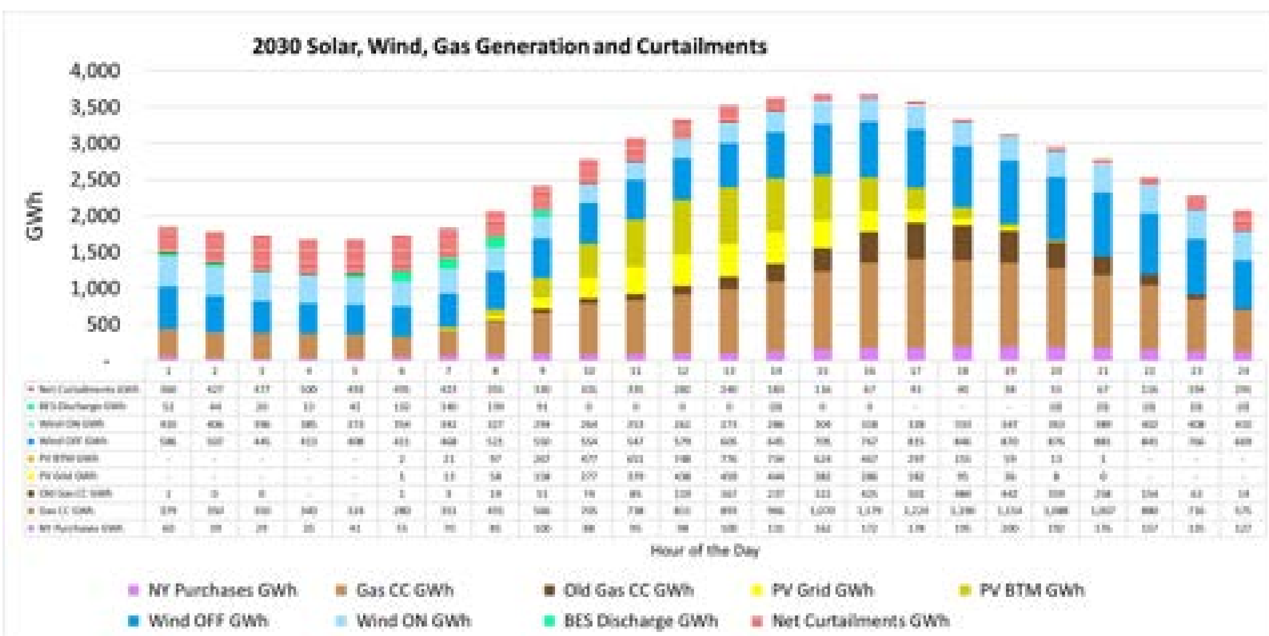


Figure 46 shows the same distribution of annual generation by hour in 2030, including curtailments.

Figure 46 2030 Solar, Wind and Gas Annual Generation by Hour



Comparing these charts shows the following:

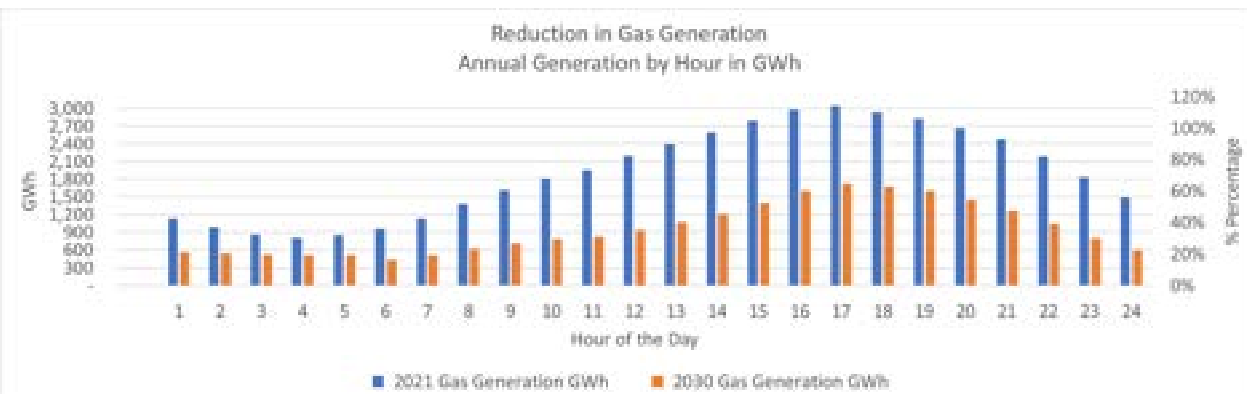
- Gas generation in 2030 is reduced by 50% from 2021.
- About 7,000 GWh of wasted solar and wind generation due to curtailments in 2030 represents 18% of wind and solar generation.
- Wind generation during low load periods early in the day leads to large curtailments. Curtailments in hours 1-6 (3,453 GWh) exceed usable generation from offshore wind (2,182 GWh) during that period.
- Solar generation in the mornings contributes to curtailments when there is wind.
- Gas generation is reduced substantially by solar during mid-day hours.
- Gas generation is only reduced by 49% during hours 18-24 primarily by wind generation.
- BESS only recovers about 665 GWh, or 9% of curtailed generation. It's occurrence early in the day is due to the ability to replace some of the minimum dispatchable generation from gas combined cycle plants early in the day when there are curtailments.

As shown below in Figure 47, the ability to reduce gas generation by adding solar and wind generation is very limited early in the day when gas generation is low.

The ability to reduce gas generation is limited by the need to provide a minimum amount of flexible generation, which is assumed to be 3% of maximum loads. Some of this flexible generation is replaced by discharging battery energy storage.

Figure 47 compares the total gas generation by hour in 2021 and 2030.

Figure 47 Reduction in Gas Generation



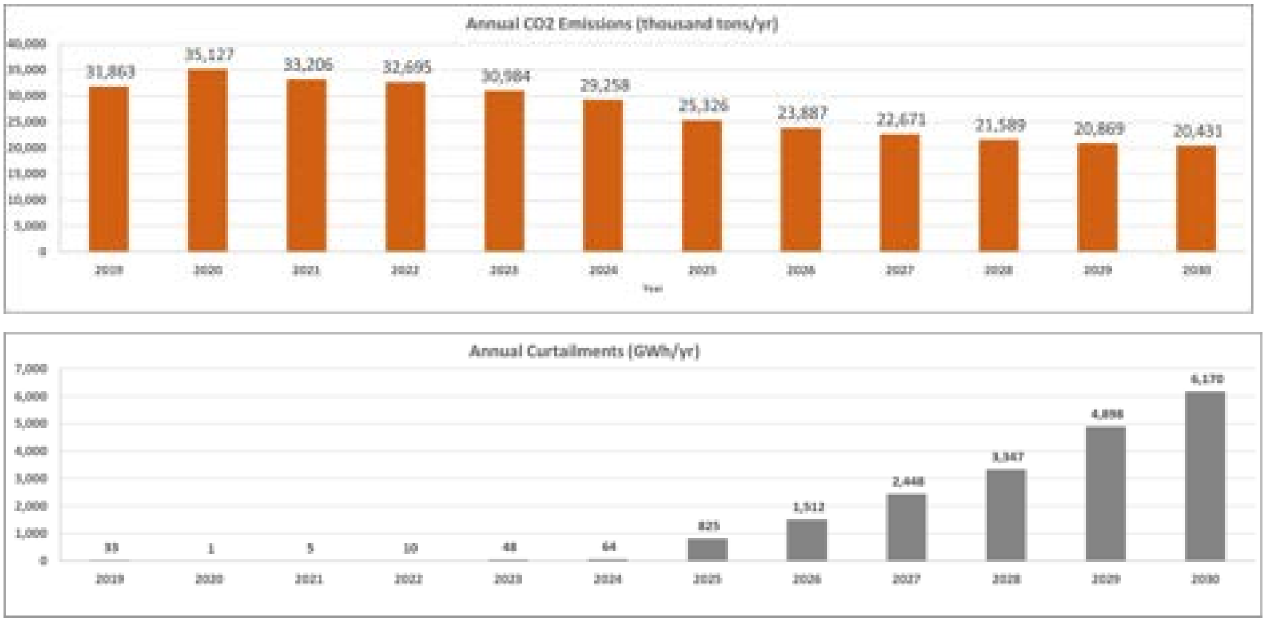
The smallest reductions in gas use occur during early hours (2-5) when a large portion of wind generation is curtailed because of low loads. The rest of the day shows over 50% reduction each hour except in the evenings as solar production declines and highest loads occur.

6.7. Changes in CO2 emissions

By 2030 about 12 million tons/year of CO_2 is avoided by solar and wind generation which displaces the operation of gas combined cycle plants.

Figure 48 below shows that annual increases in solar and wind generation have a declining effect on reducing CO2 emissions as curtailments increase.

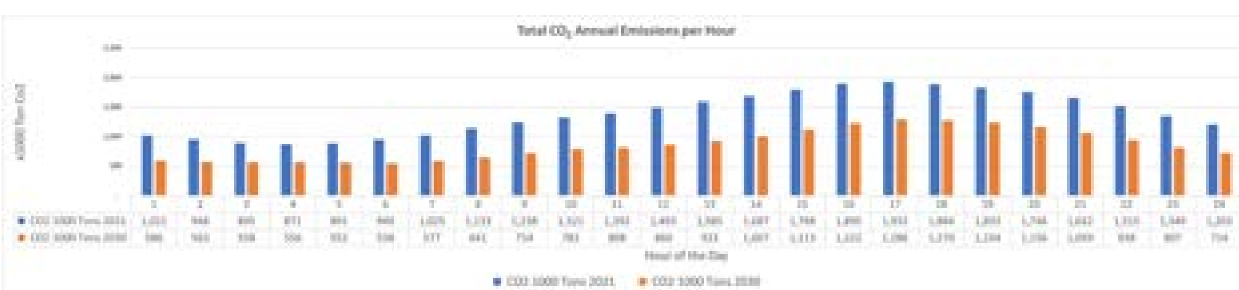
Figure 48 Decreasing CO2 Production and Increasing Curtailments



Expansion of renewable generation after 2025 becomes has a declining effect in reducing CO2 emissions because of the poor timing relationship between solar and wind generation and electric loads. During low loads and periods of plentiful sun and wind, an increasing amount of surplus energy exceed load requirements and will be wasted as curtailments. This means that each year, new solar and wind generation becomes less effective in reducing CO2 emissions, effectively increasing their carbon abatement cost. This declining effectiveness in incremental investment in wind and solar after 2024 becomes progressively expensive to consumers and taxpayers.

The following chart in Figure 49 shows annual CO2 emissions by hour for 2021 vs 2030. Total CO2 emissions drop from 33.2 to 21.0 million tons.

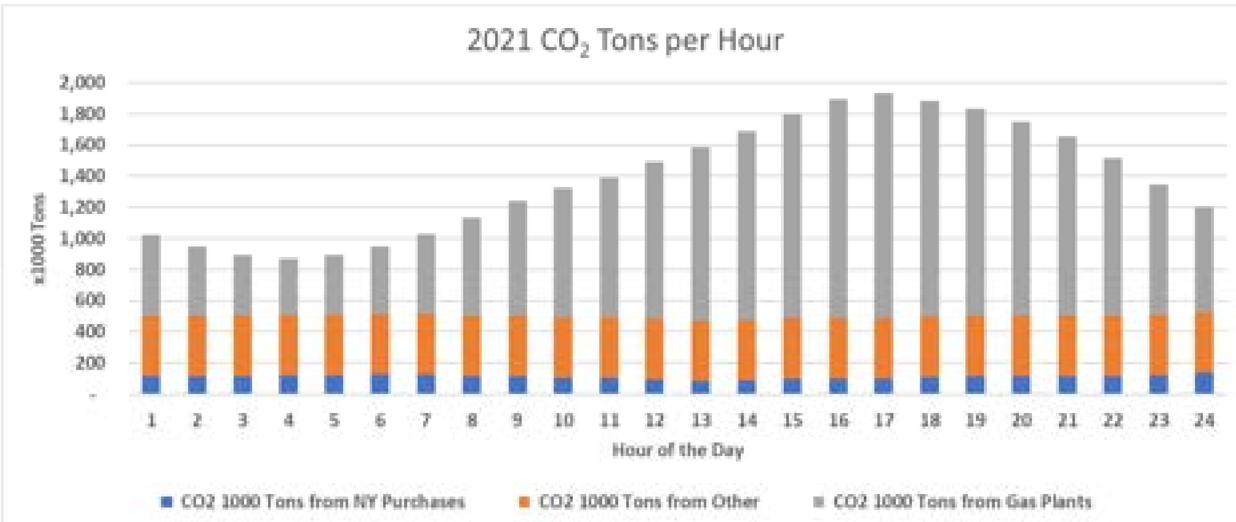
Figure 49 CO2 Annual Emissions by Hour

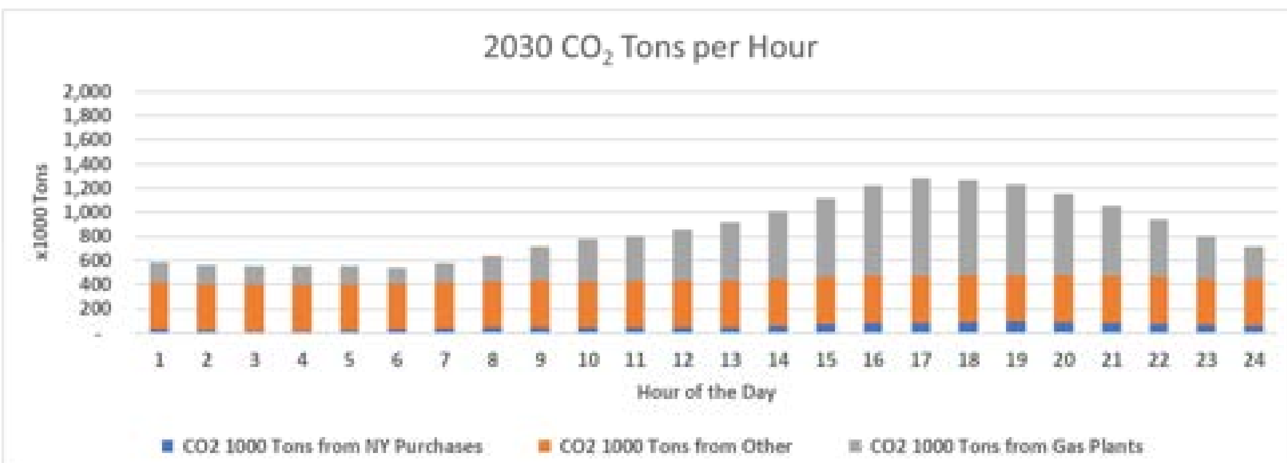


Hourly analysis of CO2 reductions illustrates the declining ability of wind and solar generation to reduce emissions from gas combined cycle plants. Solar generation only reduces CO2 emissions during mid-day periods, and wind generation is limited by its variability at other times, exceeding grid needs during low load periods.

As CO2 produced from gas firing is reduced, CO2 produced by “Other” generation (landfill gas, MSW and wood firing) becomes more significant as shown in **Error! Reference source not found.**. This evaluation assumes no change in the operation of these plants by 2030.

Figure 50 Comparison of Hourly CO2 Production in 2021 vs 2030





Reducing CO2 emissions is limited by the need for gas combined cycle plants to maintain a minimum amount of dispatchable generation for system control (assumed to be 3% of maximum annual load) which is only partially displaced by battery systems.

As gas generation (including NY purchases) decreases, its fractional contribution to CO2 emissions drops from 72% in 2021 to 56% in 2030. Other generation (wood, MSW and landfill gas) are assumed not to change. Their contribution to CO2 emissions increases from 28% to 44% during that period as gas generation is reduced. Some state energy policies rationalize these emissions to be offset by those that would have occurred due to natural biodegradation, so they are not currently targeted for reduction.

6.8. Utilization of battery energy storage

Installing 600 MW of battery energy storage (BESS) has very limited effect in recovering surplus energy during curtailments to further reduce CO2 emissions. The maximum utilization of BES with 4-hour discharge capacity is 16.67% (4 hr/24 hr) if it discharges every day. The operation of BES is further constrained by the timing of opportunities to reduce CO2 emissions.

BES can add value in several ways:

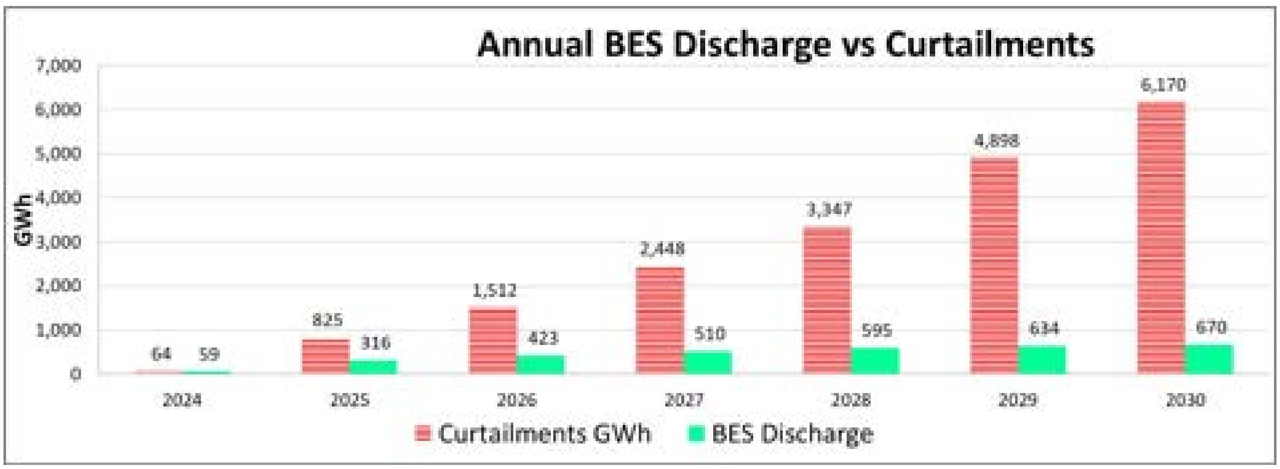
- It represents reliable capacity if charged using gas generation when wind and solar is not available during extended periods. Inexpensive reliable capacity is currently available from gas fired plants and older steam units. New reliable capacity can be provided by adding new simple cycle combustion turbines which have much lower capital costs. Standby capacity provided for reliability rarely operates and does not contribute significantly to CO2 emissions. Plants are compensated for being available when needed through the capacity market. Revenue for capacity payments is very low given the large amount of inexpensive capacity provided by existing gas and oil fired simple cycle combustion turbines and older steam plants in New England.
- BES provides flexibility to the grid by being able to charge and discharge in response to dynamic changes in the grid. Plants that do this are compensated through payments for ancillary services, which includes spinning reserve and voltage regulation functions. These services are currently provided by existing gas and hydro units. Incorporation of advanced inverter technology will provide such capability to more grid installations.
- BES can be operated to reduce the operation of gas combined cycle plants, thereby reducing CO2 emissions. Charging only occurs when there is curtailed energy available, and when there is time to discharge storage in a 24-hour cycle to reduce gas combined cycle operation. By 2030 curtailments occur about 40% of the time. This severely limits the utilization of BES to reduce curtailment of wind and solar electricity to about 5-10% depending on the relationship between the amount of battery storage installed and the amount of curtailments. Charging battery systems when there are no curtailments increases the operation of gas combined cycles, and only 85% of that energy is discharged, effectively increasing CO2 emissions.
- BES can charge when wholesale prices are low and discharge when prices are high capturing market arbitrage. Currently, pricing differentials within daily cycles is small most of the year except when summer peak loads result in operating gas peaking plants with higher gas spot prices, or during winter when gas shortages cause a shift to the use of much more expensive LNG. These variations do not often occur within 24 hour cycles allowing arbitrage. By 2030, negative pricing is estimated to occur 40% of the time

which can support substantial arbitrage when curtailments occur intermittently. However, negative pricing represents a transfer of operating subsidies for solar and wind plants into the competitive market. Since subsidies are being evaluated in terms of overall CO2 reductions, the opportunity for BES to benefit from this form of arbitrage is neglected for the purpose of this evaluation.

Many of these benefits of BES can be studied in more detail, but are not addressed in this evaluation, which focuses on the additional costs for reducing CO2 emissions. The high cost and low utilization of BES indicates that additional use for ancillary services, capacity payments, and arbitrage are not likely to substantially change the results and interpretations of this report.

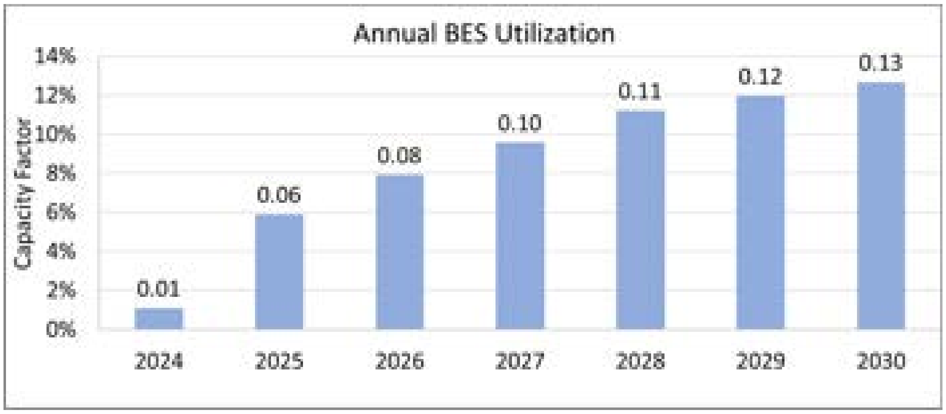
Annual utilization of BES increases with increasing curtailments as shown below in Figure 51 and Figure 52.

Figure 51 Annual BES Discharge vs Curtailments



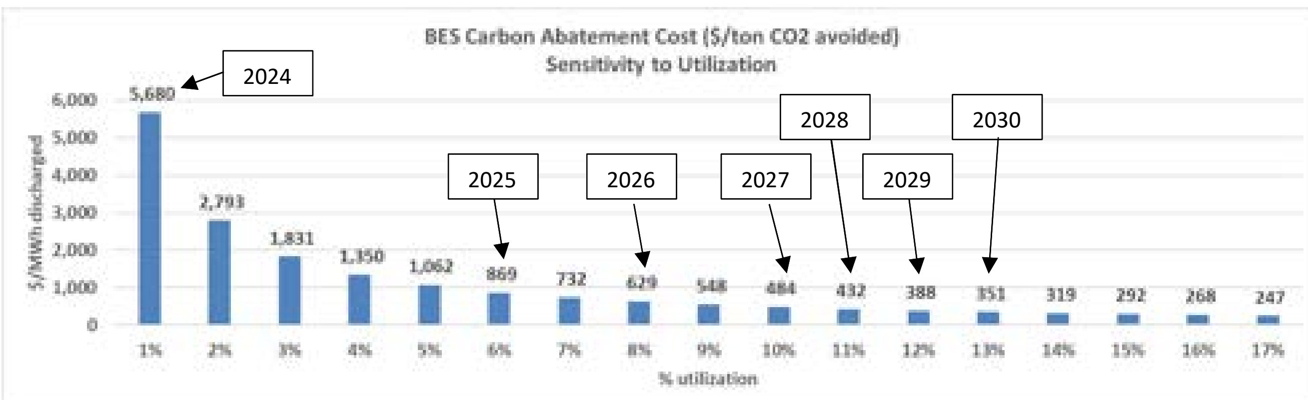
BES capacity can discharge over 600 GWh after 2028, with limited increase after that as curtailments rise. Annual BES discharge approaches a limit of under 700 GWh/year, which represents a utilization of about 13% when battery capacity is very low relative to high levels of curtailments as shown in Figure 52.

Figure 52 Annual BES Utilization



Carbon abatement costs for BES are very high but decrease with rising utilization as shown below in Figure 53.

Figure 53 Carbon Abatement Cost for Battery Storage



Based on 2020 dollars; BES cost does not include the cost of charging energy

Further analysis of BES economics is presented in the next section. At maximum utilization of 13%, the additional cost of using BES to reduce emissions is about $390/ton CO2, much larger that the carbon abatement costs for wind and solar generation except for BTM solar.

7. Grid Impacts of Wind and Solar Generation

Installing over $61B of new wind and solar generation over the next decade will unfavorably impact operation of the regional grid and wholesale markets. Understanding these impacts becomes important as long-term commitments are put in place over the next few years that will disrupt regional grid operations and reliability later. New generation is being added not in response to market signals that are driven by power grid operational needs, but by state driven policies that seek to reduce CO_2 emissions by displacing gas combined cycle plants, which provide important functionality. Hourly modeling of the grid provides the basis for evaluating the impacts of these policies.

7.1. Increasing generator inflexibility and curtailments

A large portion of regional generators are inflexible based on their design and how they are financed. Nuclear power plants are designed to operate continuously and shut down only periodically for refueling. Wind and solar plants are designed to operate whenever resource availability permits. Hydro plants operate when water flow is available unless they have storage capability. MSW plants have to operate based on commitments to eliminate municipal trash.

Figure 54 Increasing Grid Inflexible Generation

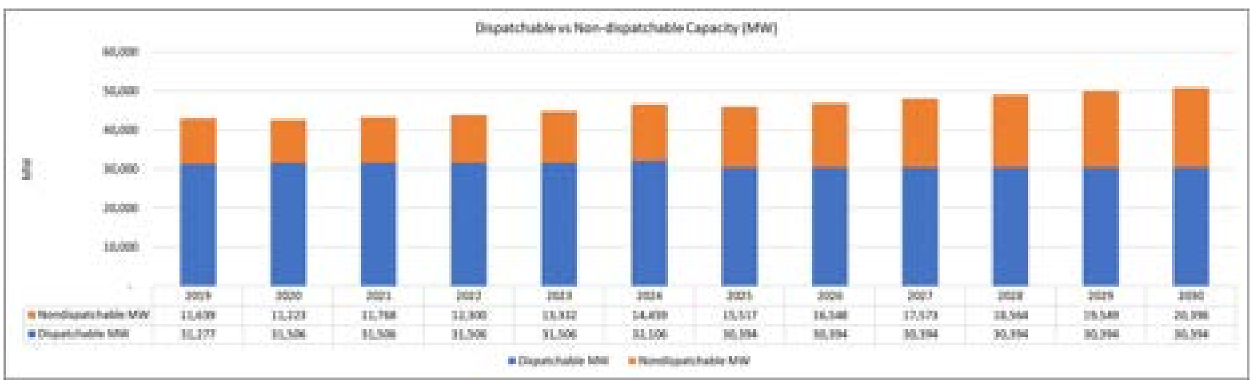
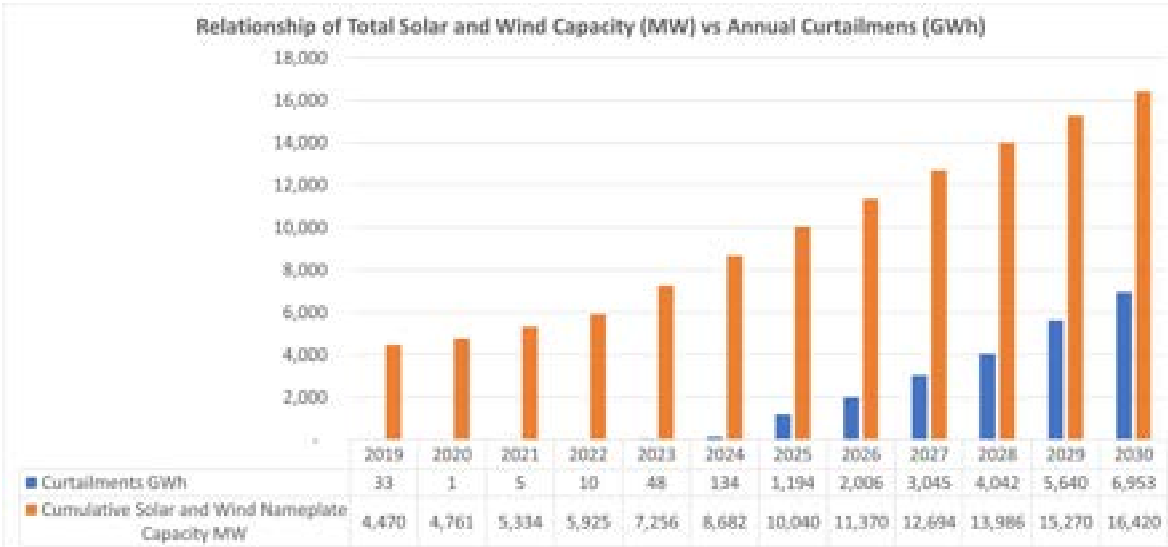


Figure 54 above shows that the doubling of onshore wind and PV, and the rapid expansion of offshore wind increase the fraction of inflexible generator capability from 25% to over 40% by 2030.

Rising inflexible generation capacity increases the likelihood that some generators that have very low operating costs will not be able to operate when there is insufficient load. This happens primarily during early morning hours when loads are lowest, and in the early summer when maximum solar generation occurs. During those hours, surplus generation could be exported to other regions or it must be turned off, or curtailed. As more wind and solar capacity is installed, there are more periods of time when some inflexible generation cannot be used as illustrated in Figure 55 below.

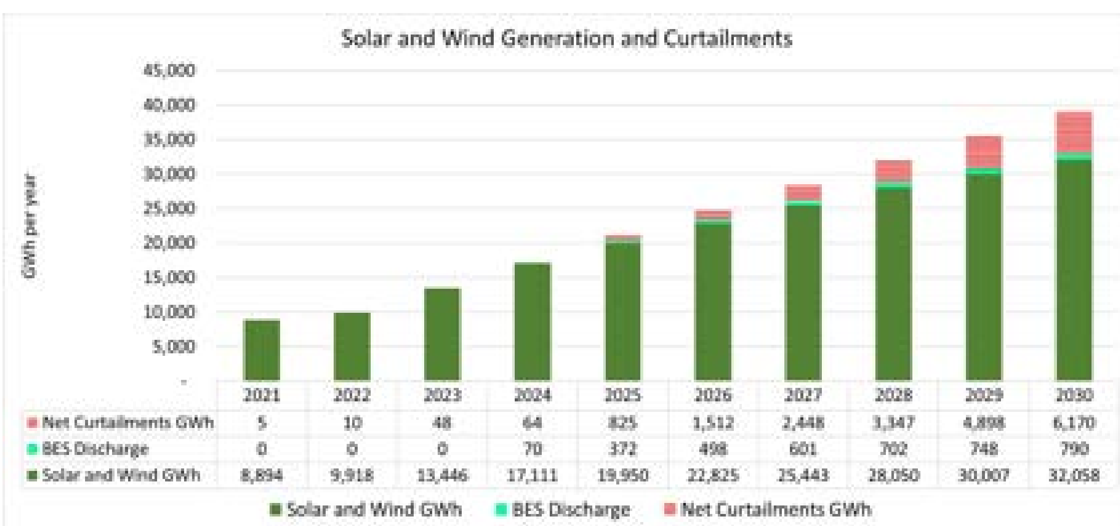
Figure 55 Annual Curtailments vs Installed Solar and Wind Capacity



Once wind and solar generation capacity grows to about 8,000 MW in 2024, annual curtailments increase faster than the rate of new solar and wind installation capacity addition. These curtailments reduce the amount of CO_2 emissions that would be displaced if the full output of wind and solar generation could be utilized.

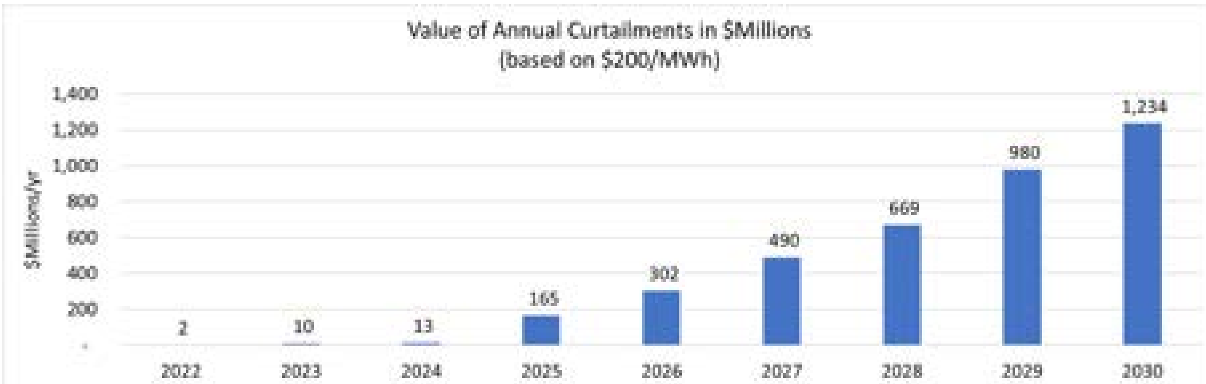
The magnitude of curtailments exceeds 18% of solar and wind generation in 2030 as shown below in Figure 56. After 2030, curtailments will rise steeply as a growing fraction of new wind and solar generation will not be usable.

Figure 56 Curtailments vs Total Solar and Wind Generation in GWh



Assuming an average total unsubsidized cost of $200/MWh for solar and wind energy, the annual cost of wasted energy from curtailments is shown below in Figure 57. This cost approaches $1.4 billion in 2030 and will increase with further installation of wind and solar generation in the future.

Figure 57 Cost of Curtailed Energy per Year



The annual cost of wasted energy from curtailments exceeds $1.2 billion in 2030. The increasing magnitude of these costs indicates a serious decline in the effectiveness of these investments and supporting subsidies. Adding substantial wind and solar generation after 2025 becomes increasingly wasteful.

7.2. Use of battery energy storage to reduce curtailments

Most state and regional decarbonization plans rely on the use of battery energy storage (BES) to compensate for the timing mismatch between solar and wind generation and loads. BES can recover some of the surplus solar and/or wind generation. Initial analysis of the hourly behavior of BES shows that there is a very limited opportunity for BES to do this.

The chart in Figure 58 below shows BES discharge duration each year as the number of days and discharge in GWh. 600 MW of BES can discharge up to 4 hours, or 2.4 GW each day.

Figure 58 BES Utilization Increase by Year

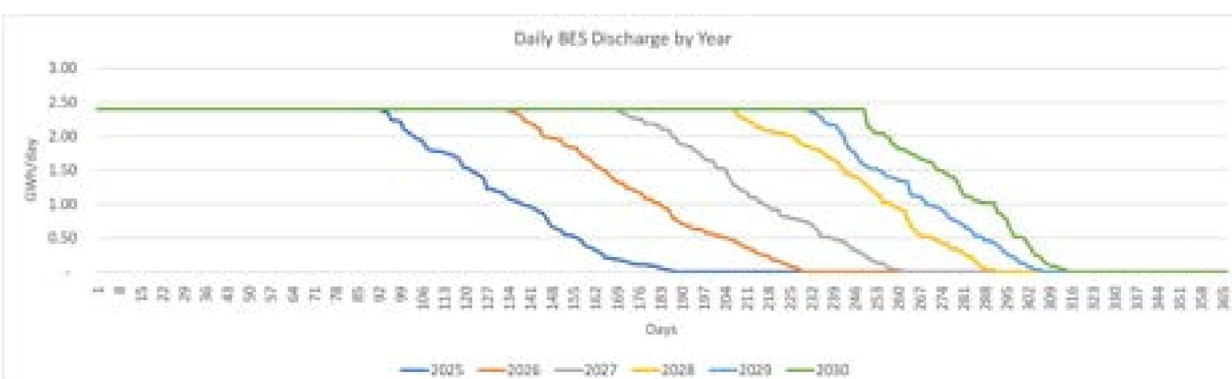
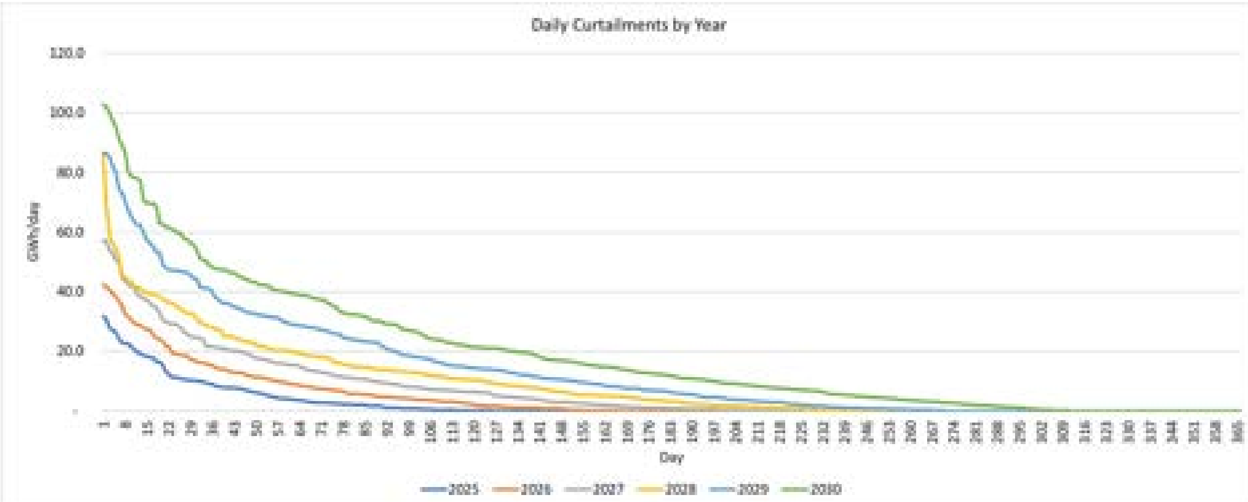


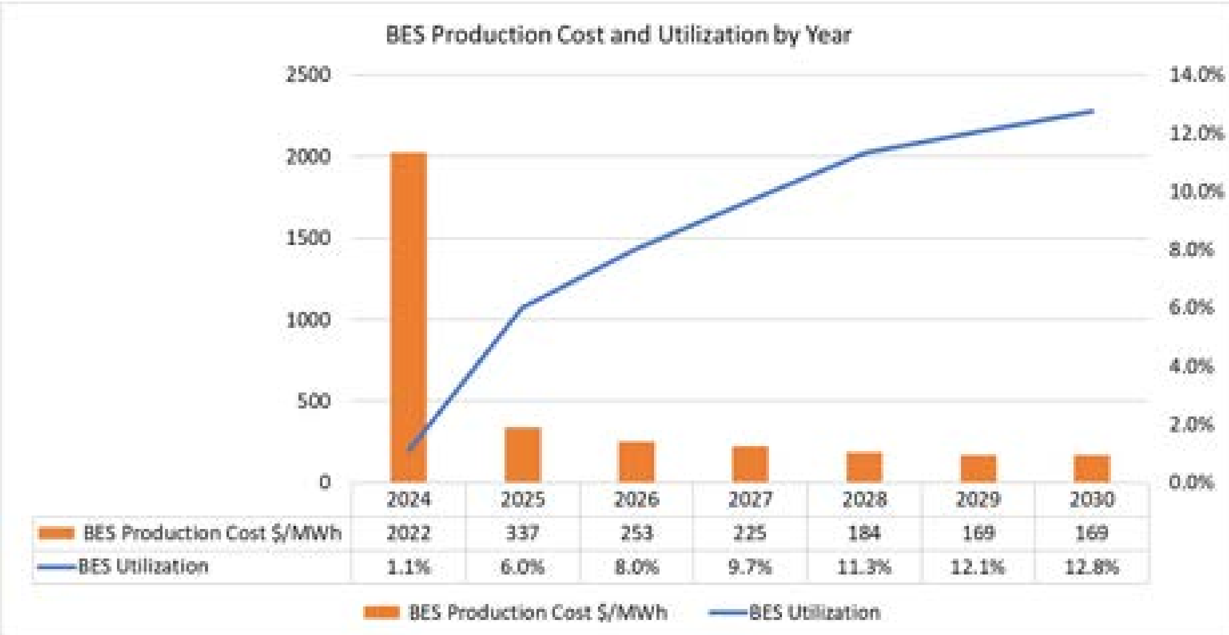
Figure 59 Daily Curtailments Increase by Year



Note that most of the curtailments occur during less than a third of the year. Comparing this chart with Figure 60 shows that a very large amount of BES capacity would need to be installed to significantly impact curtailments during a small part of the year.

The 600 MW of BES installed in 2023 represents an investment of about $6.2 billion. Production costs for BES represent recovery of this investment and operating costs as energy payments. Production costs decline as utilization increases, from over $2000/MWh discharged in 2024 to under $170/MWh as utilization increases to almost 13% by 2030 as shown in Figure 61 below. It is assumed that other income for capacity payments and ancillary services are similar to those for combined cycle plants that are displaced by BES discharge. Production costs are in 2020 dollars and exclude the potential effect of negative pricing when charged during curtailments.

Figure 60 600 MW BES Utilization and Production Cost by Year

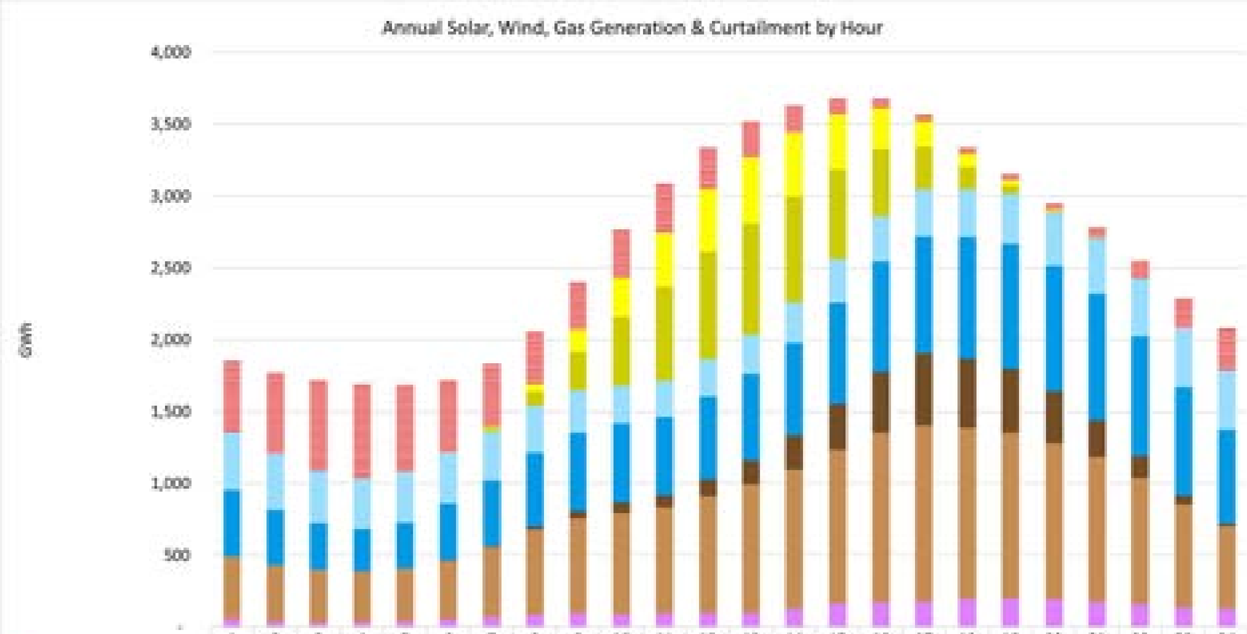


Several cases are evaluated to examine the impact of installing additional BES as follows:

- Figure 61 shows annual generation by hour in 2030 with no BES operating.
- Figure 62 shows annual generation by hour in 2030 with 600 MW of BES operating
- Figure 63Figure 63 shows annual generation by hour in 2030 with 1800 MW BES operating.
- Figure 64 shows annual generation by hour in 2030 with 4200 MW BES operating.

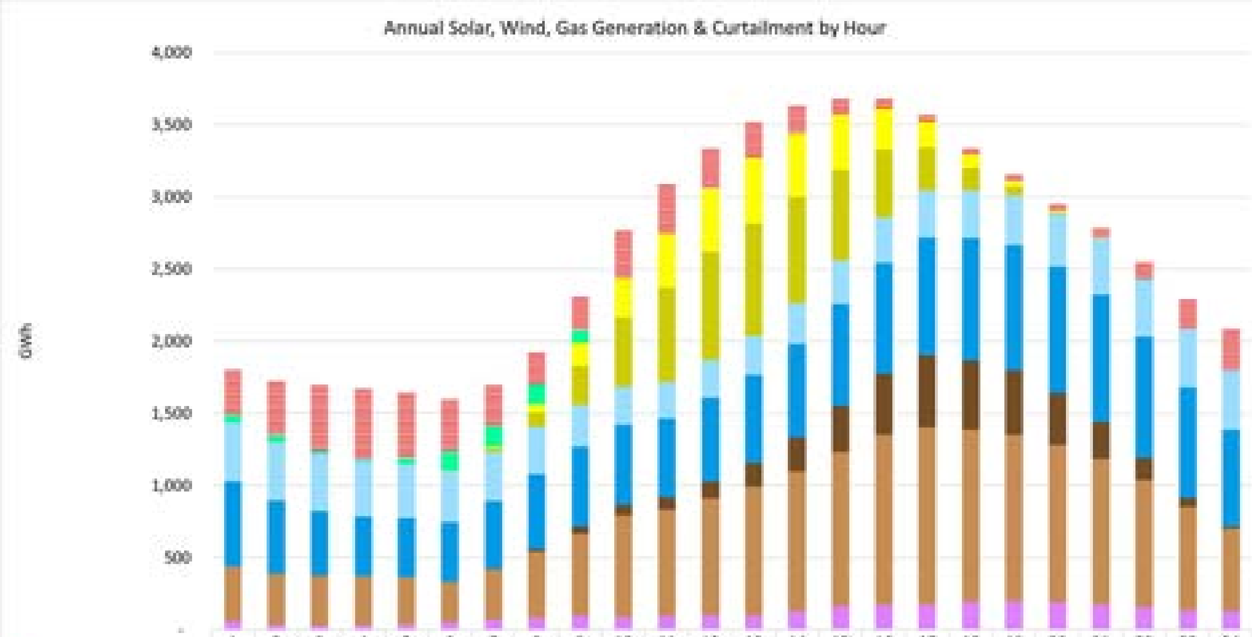
Note that generation from nuclear, hydro, and “Other” categories are excluded from these charts since they do not change significantly each year. Purchases from Canada are also excluded since they do not change after 2024.

Figure 61 2030 Hourly Generation without BES



	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Net Curtailments GWh	490	567	627	652	606	511	435	362	334	335	339	288	243	186	117	68	43	40	39	57	70	124	206	305
BES Discharge GWh	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	-	-	-	(0)	(0)	(0)	(0)	(0)	(0)
PV Grid GWh	-	-	-	-	-	1	13	58	158	277	379	438	459	444	382	286	182	95	36	8	0	-	-	-
PV BTM GWh	-	-	-	-	-	2	21	97	267	477	651	748	776	734	624	467	297	155	59	13	1	-	-	-
Wind ON GWh	402	388	366	349	347	353	342	327	294	264	252	261	273	286	304	318	328	333	347	363	389	402	408	410
Wind OFF GWh	464	384	325	299	322	392	457	514	546	550	543	575	602	642	703	766	815	846	870	874	878	833	754	655
Old Gas CC GWh	1	0	0	-	-	1	3	19	52	74	85	119	167	237	322	425	501	484	442	359	258	154	63	14
Gas CC GWh	431	394	370	352	366	412	491	594	656	705	738	811	893	966	1,07	1,17	1,22	1,19	1,15	1,08	1,00	880	716	575
NY Purchases GWh	60	39	29	35	41	55	70	85	100	88	95	98	100	131	162	172	178	195	200	192	176	157	135	127

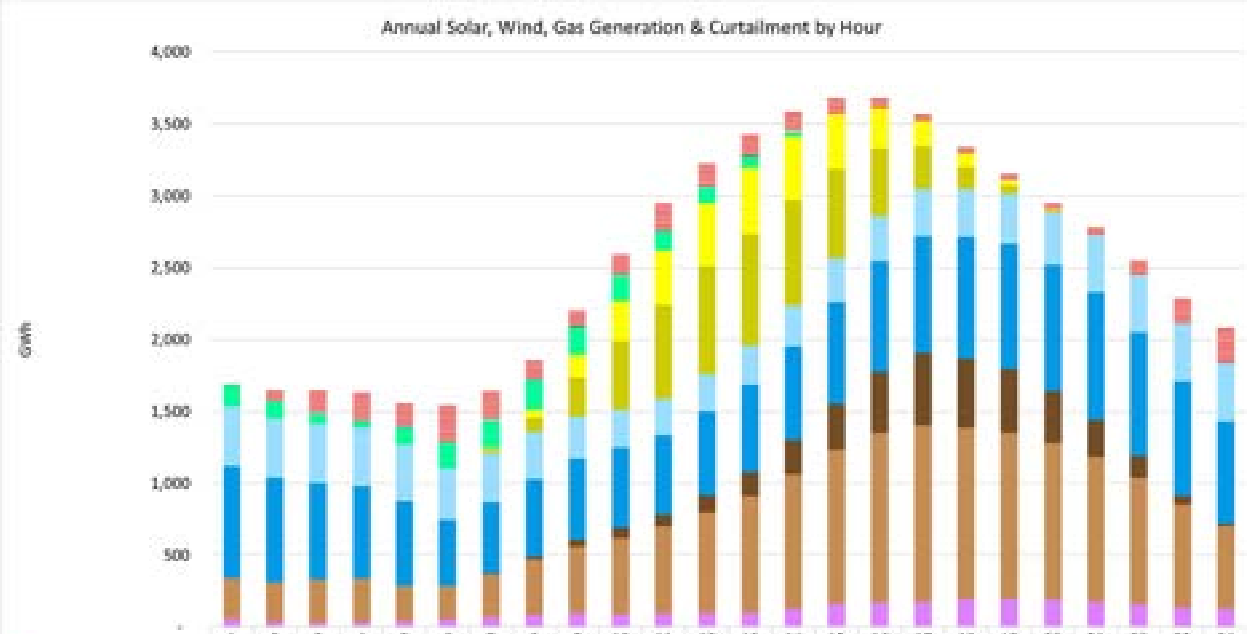
Figure 62 2030 Hourly Generation with 600 MW BES



	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Net Curtailments GWh	308	382	457	488	451	359	283	217	239	331	335	282	240	183	116	67	43	40	38	55	67	116	194	291
BES Discharge GWh	52	44	20	12	42	132	140	139	91	0	0	0	0	(0)	0	0	-	-	-	(0)	(0)	(0)	(0)	(0)
PV Grid GWh	-	-	-	-	-	1	13	58	158	277	379	438	459	444	382	286	182	95	36	8	0	-	-	-
PV BTM GWh	-	-	-	-	-	2	21	97	267	477	651	748	776	734	624	467	297	155	59	13	1	-	-	-
Wind ON GWh	410	406	396	385	373	354	342	327	294	264	253	262	273	286	304	318	328	333	347	363	389	402	408	410
Wind OFF GWh	586	507	445	413	408	411	468	521	550	554	547	579	605	645	705	767	815	846	870	876	881	841	766	669
Old Gas CC GWh	1	0	0	-	-	1	3	19	51	74	85	119	167	237	322	425	501	484	442	359	258	154	63	14
Gas CC GWh	379	350	350	340	324	280	351	455	566	705	738	811	893	966	1,07	1,17	1,22	1,19	1,15	1,08	1,00	880	716	575
NY Purchases GWh	60	39	29	35	41	55	70	85	100	88	95	98	100	131	162	172	178	195	200	192	176	157	135	127

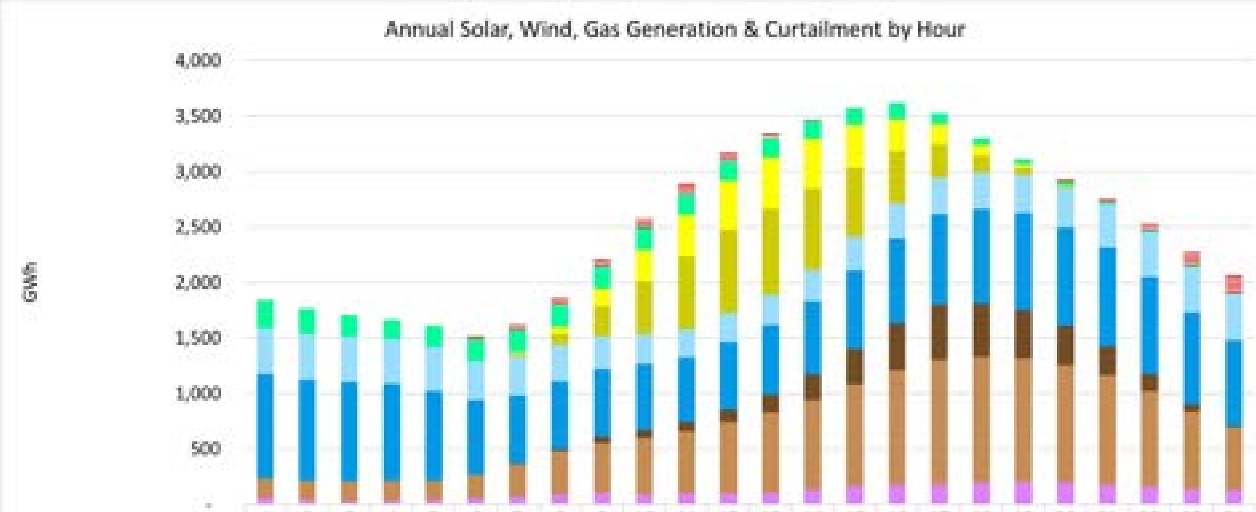
NY Purchases GWh Gas CC GWh Old Gas CC GWh Wind OFF GWh Wind ON GWh
PV BTM GWh PV Grid GWh BES Discharge GWh Net Curtailments GWh

Figure 63 2030 Hourly Generation with 1800 MW BES



	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Net Curtailments GWh	13	82	167	202	174	259	201	132	118	146	192	168	153	148	114	67	43	40	38	51	59	97	166	248
BES Discharge GWh	149	121	68	50	120	180	192	205	198	177	136	111	82	32	-	-	-	-	-	-	-	(0)	(0)	(0)
PV Grid GWh	-	-	-	-	-	1	13	58	159	279	379	438	459	444	382	286	182	95	36	8	0	-	-	-
PV BTM GWh	-	-	-	-	-	2	21	97	267	477	651	748	776	734	624	467	297	155	59	13	1	-	-	-
Wind ON GWh	414	411	407	403	392	358	346	330	298	264	253	262	273	286	304	318	328	333	347	363	389	402	408	410
Wind OFF GWh	781	726	676	644	589	458	494	537	560	560	553	582	609	648	706	767	815	846	871	879	889	859	794	712
Old Gas CC GWh	1	0	0	-	-	1	3	19	50	72	85	119	167	237	322	425	501	484	442	359	258	154	63	14
Gas CC GWh	281	273	301	302	246	232	299	389	459	530	602	700	811	933	1,07	1,17	1,22	1,19	1,15	1,08	1,00	880	716	575
NY Purchases GWh	60	39	29	35	41	55	70	85	100	88	95	98	100	131	162	172	178	195	200	192	176	157	135	127

Figure 64 2030 Hourly Generation with 4200 MW BES



	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Net Curtailments GWh	(25	(21	(17	(15	(12	39	62	60	60	77	113	80	47	7	(41	(81	(58	(18	(5)	19	36	69	118	183
BES Discharge GWh	257	224	193	174	194	199	199	200	201	199	179	171	169	162	153	146	101	57	42	30	19	15	13	8
PV Grid GWh	-	-	-	-	-	1	13	59	160	282	383	443	462	444	382	286	182	95	36	8	0	-	-	-
PV BTM GWh	-	-	-	-	-	2	21	97	267	477	651	748	776	734	624	467	297	155	59	13	1	-	-	-
Wind ON GWh	414	411	407	403	395	351	353	334	301	271	258	267	276	287	304	318	328	333	347	363	389	402	408	410
Wind OFF GWh	938	918	895	874	808	669	619	609	609	597	581	601	622	657	708	768	815	847	872	882	894	873	830	769
Old Gas CC GWh	1	0	0	-	-	1	3	19	51	74	85	119	166	236	321	424	501	484	442	359	258	154	63	14
Gas CC GWh	173	170	177	178	172	213	292	394	455	506	560	640	725	804	918	1,0	1,1	1,1	1,1	1,0	988	865	704	567
NY Purchases GWh	60	39	29	35	41	55	70	85	100	88	95	98	100	131	162	172	178	195	200	192	176	157	135	127

Table 5 below summarizes BES effectiveness for the three cases shown above, plus for 4200 MW in 2030.

Table 5 Comparison of BES Effectiveness in 2030

Installed BES MW	Investment ($B)	BES Discharge (GWh)	BES Utilization (%)	BES Carbon Abatement Cost ($/ton CO2)	Gas Plant GWh (incl NY purchases)	CO2 Emissions million tons/year
0		0	NA	NA	24.7	20.7
600	$0.8	670	13%	$302	24.1	20.4
1800	$2.4	1,820	12%	$335	22.9	19.9
4200	$5.6	3,399	9%	$477	21.4	19.2

The declining effectiveness of adding battery storage is not just limited by the high cost, but by the limited opportunity to utilize BES to recover surplus energy to reduce CO2 emissions within 24 hour cycles. Carbon abatement cost for operating 600 MW BES is $302/ton in 2030 based on relatively high utilization of 13%. If BES is increased to 1800 MW, carbon abatement cost increases to $335/ton as utilization drops to 12%. Increasing BES to 4200 MW increases carbon abatement cost to $477/ton as utilization drops to 9%. These costs are in addition to the carbon abatement costs estimated for wind and solar generation to generate the surplus energy. Installing more BES increases the recovery of surplus energy but at growing cost because utilization decreases, increasing carbon abatement costs.

BES effectiveness is highly sensitive to the assumption that 3% of the maximum annual load has to be provided all of the time by flexible generation other than hydro. This allows BES to discharge even during curtailments to reduce gas generation. If flexibility is provided by other means such as advanced technology inverters, battery utilization would be even lower given less opportunities to reduce gas generation.

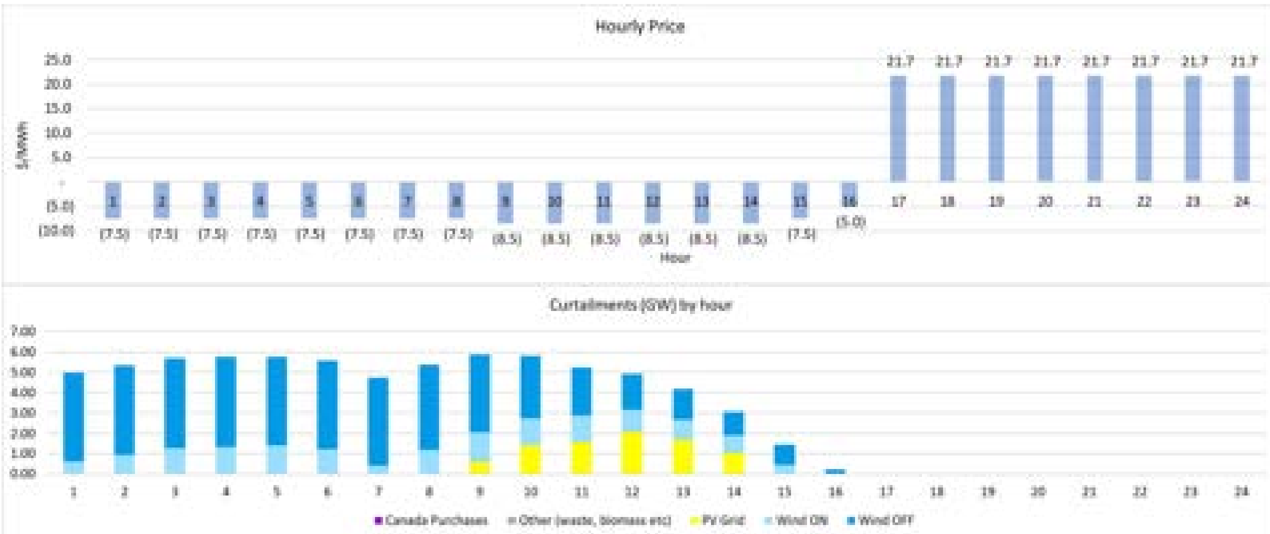
Based on this analysis, BES is clearly not a cost-effective option for recovering energy from surplus solar and wind, and has declining effectiveness if more capacity is added.

7.3. Negative energy pricing

As energy surpluses grow so does the amount of time that the competitive wholesale energy market by is disrupted by negative pricing. Negative pricing occurs when the owner of a subsidized generator threatened with curtailment receives payments for production tax credits and/or clean energy credits. Also, the operator of an offshore wind generation facility may have to pay penalties or lose above-market payments if they are curtailed based on power sales agreements. When threatened by curtailment during the bidding process, the owner can share the value of subsidies that would be lost with the market by offering to pay to run via negative pricing. This is disruptive because many generators which have to run, and those that are needed for flexibility and control, do not receive subsidies and will have to pay to operate. These costs to maintain system flexibility will have to be covered through additional payments to these generators or they are not likely to stay in operation when needed.

The chart below in Figure 65 shows an example of hourly curtailments and pricing for a day in May, 2030.

Figure 65 Example of Hourly Pricing During Curtailments



Indicative hourly price calculations use simplified assumptions, including nominal variable operating costs and the application of uniform regional operating subsidies. Each generating category has a different hourly bid price based on an assumed variable cost. The sum of assumed regional uniform production tax and clean energy credits are applied to provide a rough indication of bidding behavior. Although no variable costs are estimated by EIA for wind and solar generation, small values are assigned to differentiate the behavior of each type of wind and solar plant to illustrate the effect of negative pricing. The model does not attempt to address variations in operating subsidies by state. These pricing assumptions are intended only to illustrate the general effect of negative pricing and how often it occurs.

The chart below in Figure 66 plots price duration for 2021 and 2030 and shows how much of the time prices are negative. Prices were rarely negative in 2021 but are projected to be negative about 40% of the time in 2030. Plotted prices are indicative as discussed above.

Figure 66 Price Duration

It is difficult to predict how wind and solar generators will behave in the competitive wholesale market as they respond to progressively increasing curtailments and negative pricing, possibly offset by increasing subsidies varying by state. Understanding the occurrence and impacts of negative pricing needs to consider how renewable installations are financed and subsidized, and how their variable generating costs are determined.

The impacts of negative pricing require further study. There are obvious impacts to the annual income of each generator type based on hourly operation and pricing. Lower prices or negative prices could change consumer energy use patterns and encourage changes to end-user equipment, such as energy storage or scheduling appliance use. If negative pricing is extended to end-users, this could lead to wasteful and less efficient use of energy.

Negative pricing will severely reduce revenue to many plants and could result in earlier retirements, with loss of generation capacity and possibly increased CO2 emissions if non-emitting generators retire. Negative pricing may discourage further investments to restore lost capacity or to extend the economic lives of many plants that have to operate during surpluses. This is an area currently under study by the ISO-NE Planning Advisory Committee. (ISO New England, n.d.)

Extensive negative pricing will severely impact nuclear power generation which does not receive the same subsidies as solar and wind generation, and would have to pay to run much of the year. Plants may be forced to extend refueling outages during the spring months when solar generation is the greatest. Investments to obtain and maintain operating license extensions may be more difficult for owners to justify.

As an example of how negative pricing will reduce revenues, the chart below in Figure 67 provides an indication of how total revenue for onshore wind generation increases from 2021 to 2024 until offshore wind capacity expands. As surpluses and negative pricing escalate after 2024, annual revenue drops significantly making it more difficult to rationalize investments in new onshore wind capacity additions. Reduced annual income from market sales will require increased subsidies to cover investment recovery.

Figure 67 Onshore Wind Average Revenue

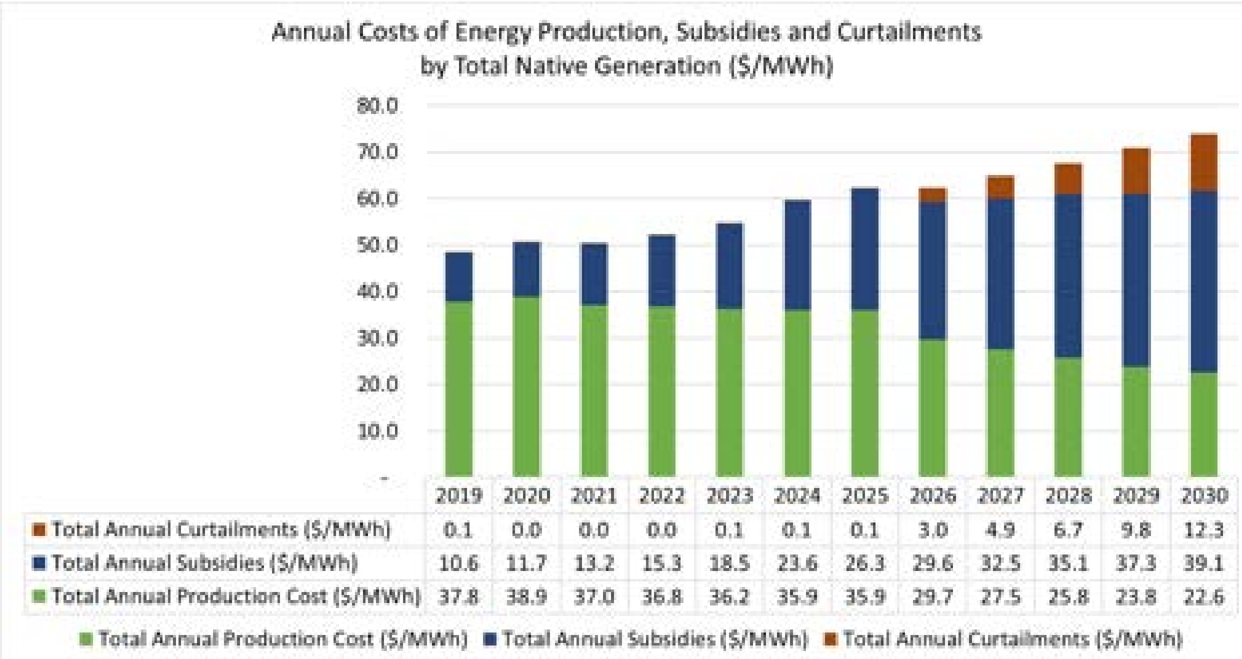
Negative pricing represents the transfer of operating subsidies for wind and solar plants into the competitive wholesale energy market. This raises fundamental questions about the role of different state energy policies in shaping a single regional power grid. Negative pricing reduces reliance on market revenue and increases the need for subsidies. Plants that do not have access to subsidies may not survive unless other sources of revenue (such as capacity payments or payments for ancillary services) increase. Since subsidies vary by state, private investment and consumer costs are impacted unevenly. The costs for achieving decarbonization may not be fairly distributed relative to the intended global benefit.

The average annual wholesale price of energy will decrease as growing energy surpluses drive more negative pricing. This means that consumers will see lower prices for the portion of their electric bills for wholesale electricity purchased by their electric distribution utility. However, the rise in the cost of subsidies, needed to replace the loss of market revenue to non-carbon emitting projects, is likely to be much larger the reduction in wholesale power costs.

Figure 68 below shows the declining trend in the average price of wholesale electricity resulting from the increased occurrence of negative pricing, which occurs 40% of the time by 2030. Figure 69 shows how these reductions in wholesale prices are more than offset by increases in the rising cost of subsidies to ratepayers and taxpayers, excluding costs for transmission and distribution improvements needed to support growth of wind and solar installations.

Figure 68 Drop in Average Price of Wholesale Electricity

Figure 69 Annual Changes in Subsidies, Market Pricing and Curtailments



	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Total Annual Curtailments ($/MWh)	0.1	0.0	0.0	0.0	0.1	0.1	0.1	3.0	4.9	6.7	9.8	12.3
Total Annual Subsidies ($/MWh)	10.6	11.7	13.2	15.3	18.5	23.6	26.3	29.6	32.5	35.1	37.3	39.1
Total Annual Production Cost ($/MWh)	37.8	38.9	37.0	36.8	36.2	35.9	35.9	29.7	27.5	25.8	23.8	22.6

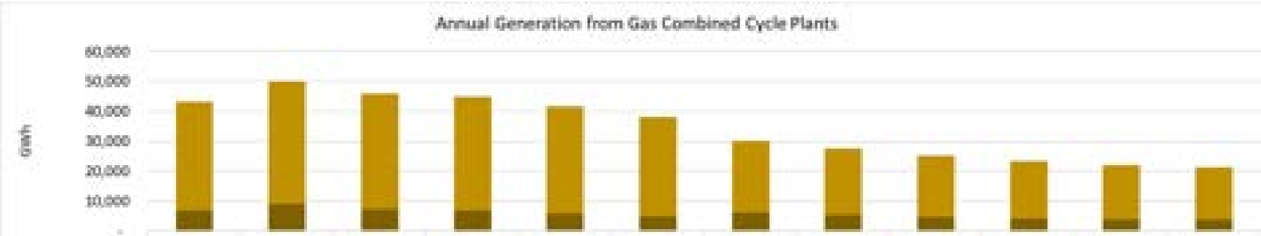
Subsidies are estimated as the difference between total costs and market value set by gas combined cycle plants. Actual subsidies can be much higher because of inefficiencies in their administration and application. A more detailed review of the effectiveness of subsidies is needed at the state level, which is beyond the scope of this report.

Lower wholesale pricing is bad for generators but good for consumers. Consumers in states that pursue large power purchase agreements with new offshore wind projects will be locked into purchasing much of their power from these projects for decades and will see less benefit from lower wholesale market pricing during surpluses. Similarly, the state commitments to provide energy credits extend decades into the future, committing ratepayers to bear those costs. These long-term effects need further study to understand the impact on electric rates and consumers in each state.

7.4. Reduced utilization of gas combined cycle plants

Gas combined cycle plants will see reduced utilization, as intended to reduce CO2 emissions. The chart below in Figure 70 shows the annual decline in utilization.

Figure 70 Annual Energy Production from Gas Combined Cycle Plants



	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Gas CC GWh	36,292	40,807	38,646	38,001	35,607	33,104	23,817	22,038	20,500	19,088	18,187	17,576
Gas CC Old GWh	6,944	9,075	7,340	6,947	5,888	4,932	6,295	5,433	4,771	4,218	3,910	3,780

The fleets of newer and older gas combined cycle plants will see a major decline in annual revenue resulting from reduced energy production. This reduces their ability to fund major plant repairs and improvements needed to extend their economic lives. A combined cycle plant that does not operate much during the year would have to survive only on capacity payments and payments for ancillary services, if they are able to provide those.

Most of the generation from gas combined cycle plants occurs during times when there are no curtailments and when prices are positive. However, these estimates assume that 3% of the maximum annual load must be provided at any time by flexible generation. Gas combined cycle plants provide this flexibility, unless they can be replaced with BES discharge (when they can be charged with surplus solar or wind energy). This represents about 6800 GWh per year, of which about 670 GWh can be replaced by discharging BES in 2030. Therefore, most of this minimum dispatchable generation will have to pay to run about 40% of the time in 2030.

Further study is needed to understand the impact of reduced operation and reduced revenue on the remaining life of gas combined cycle plants that will continue to be needed for peak loads and system flexibility. Higher payments through the capacity market and for ancillary services can offset reduced revenue from energy sales, but will increase costs to ratepayers.

Operating gas combined cycle plants to balance increasing load changes with higher variability reduces their fuel efficiency, increases CO_2 emissions, and increases operating costs. These changes are expected to be significant but have not been represented in model projections.

7.5. Early retirements

According to ISO-NE regional planning documents, the entire existing fleet of gas combined cycle plants, minus a few retirements (primarily Mystic Station), will be needed for system adequacy, reliability and flexibility over the next decade.

Asset managers of privately owned plants will see a reduced ability to cover fixed O&M costs or required capital improvements from declining energy revenue. Unless additional revenue is obtained from the capacity market or other sources, a reduction in projected return on investment and a decline in asset value could drive consideration of early retirement.

Evaluation of carbon abatement costs should also consider the higher capacity payments needed to retain existing gas combined cycle plants as their utilization declines. This report does not attempt to model the capacity and ancillary services markets which are continuously evaluated by ISO-NE.

The remaining life of solar and wind generators may be challenged as their income shifts heavily to subsidies. Expiration of performance tax credits shifts the burden of paying fixed costs to clean energy credits. If clean energy credits by themselves fall short of covering fixed costs and return on investment, decline in output and premature retirements could result. Asset managers of privately owned solar and wind plants seeing an income shift from subsidies to market revenue may have difficulty justifying additional investments to recover lost capacity, extend life of existing plants, or repower aging installations. These concerns justify further study both at a regional level and in evaluation of the effectiveness of each state energy policy.

8. Effectiveness of Decarbonization Policy

Replacing gas power generation with solar, gas and energy storage facilities encounters major technical and economic limits that need to be fully understood before additional major commitments are made for long term subsidies and investments.

Hourly modeling and determination of carbon abatement cost provide a basis for evaluating policy effectiveness. Establishing valid data and assumptions for this analysis requires collaboration to incorporate a wide range of information including power plant design and operations, project ownership and financing, power grid reliability and operations, operation of wholesale markets, variability of resources and load, utilization of available generation, and the economic effects of subsidies and surpluses.

The reliability and adequacy of our future power system will be impacted. Asset management decisions will respond to state mandates and available subsidies, shifting away market needs. Fragmented policies by state lead to uneven, and possibly unfair distribution of costs to consumers. Subsidies focused on solar, wind and battery technology discourage innovation and may discourage investment in better options.

The concept of a Social Cost of Carbon is difficult and elusive, but forms an important balancing point between underinvestment in decarbonization which could harm the future environment, versus over-investing which damages consumers and the regional economy.

The limited longevity of solar, wind and battery installations raises the question of longer term strategies. Building more solar and wind capacity than can be absorbed by loads leads to wasted surpluses and drives subsidies into the wholesale market through negative pricing which can undermine other long term needs for adequate and reliable generation. We are reaching a “tipping point” in a few years where further investment in wind and solar generation becomes progressively ineffective and expensive to consumers.

About $10 billion has been invested in wind and solar generation to avoid 4.2 million tons per year of CO_2 from gas combined cycle plants. Over $60 billion more may be spent by 2030 to double solar and onshore wind capacity, and to add 5,600 MW of offshore wind generation which collectively reduce annual CO_2 emissions by another 13 million tons. Annual rate and tax subsidies increase from about $1.3 billion in 2021 to over $3.6 billion in 2030.

Several key questions are addressed below to summarize and interpret the relationships between the cost and value of decarbonization expenditures evaluated in this report.

8.1. How do we justify investments to reduce CO2 emissions?

Raising taxes and electric rates to consumers diverts limited financial resources with the objective of achieving improvements in future climate. The projected cost of damage resulting from man-made CO2 emissions becomes the central basis for evaluating cost effectiveness. The Social Cost of Carbon (SCC) is perhaps the most difficult concept to understand and agree upon. It has been generously estimated by the Biden administration (and previously the Obama administration) at $51/ton, documented by an extensive analysis of the present value of costs of possible damage resulting from man-made CO2 emissions. This is currently the only policy guidance available in the U.S. to set a balance between under-investing in decarbonization which may increase damage from future climate damage, versus overinvesting which will hurt consumers and the regional economy. Current state policies in New England disregard this metric and target achieving Net Zero emissions without specific economic criteria.

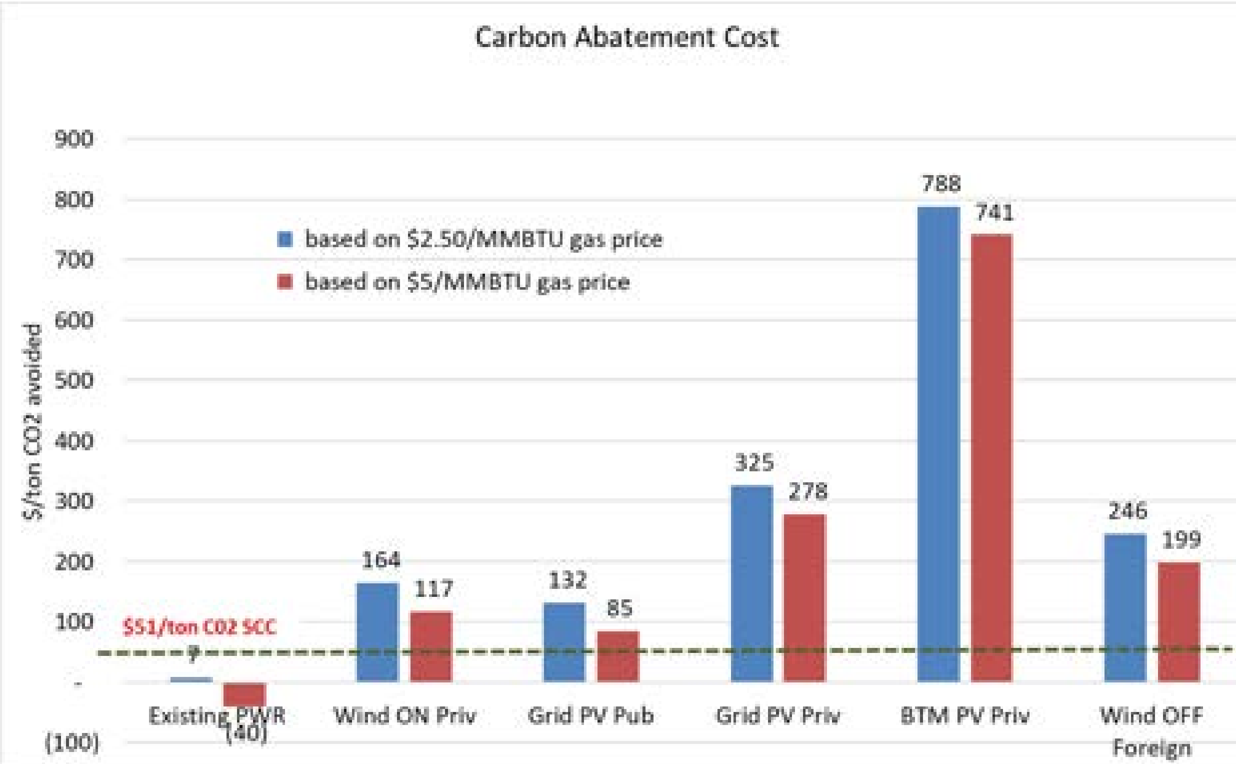
We can justify investments to reduce carbon emissions by comparing the cost of proposed decarbonization options to the cost of not reducing emissions. SCC deserves extensive independent review and public discussion given its importance as the policy benchmark for this. It must also consider the value of small regional reductions in New England relative to the much larger continuing overall growth in global emissions which may not support the intended benefits. SCC determination has varied by administration, and the uncertainty in such future guidance makes it difficult to establish long term policies with clear economic criteria.

8.2. How cost effective are investments in solar and wind generation to reduce CO2 emissions?

Climate legislation requires determination of cost effectiveness. Carbon abatement cost measures the cost of eliminating one ton of CO2 emissions, which is the sum of incremental costs divided by the amount of CO2 avoided. Calculating carbon abatement cost provides a useful metric to compare, prioritize and limit decarbonization policy initiatives.

The chart below in Figure 71 presents estimated carbon abatement costs using the assumptions documented in this report for major technologies and for various forms of ownership. These results are highly sensitive to a number of assumptions, such as natural gas pricing, that have been carefully documented and reviewed with a number of organizations and individuals. The modeling and data used for this report will be shared to support updates further analysis.

Figure 71 Comparison of Carbon Abatement Costs and SCC



Adding solar and wind generation is not a cost-effective path to achieving decarbonization relative to an SCC of $51/ton CO2. The carbon abatement costs for solar and wind generation range from 2 to 15 times that value. More importantly, the wide range of carbon abatement costs suggest prioritization by cost should be considered. BTM solar stands out as far more expensive than other options. The substantial cost of major improvements to transmission and distribution systems to enable these installations are not included and justify further investigation to determine their impact on carbon abatement cost. Also not included are the cost and emission impacts of running gas combined cycle plants less efficiently to manage increasingly variable loads.

Solar and wind carbon abatement costs, even without the cost of transmission and distribution improvements are much higher than justified by an SCC estimate of $51/ton CO2. Given uncertainties in the determination of SCC, it is important to evaluate relative carbon abatement costs among these and other technology options. Carbon abatement costs increase beyond those shown as excess solar and wind energy is curtailed, reducing their utilization, and when other costs such as related grid improvements are added.

At about $750/ton CO2, BTM solar represents the most expensive way to reduce CO2 emissions and the poorest investment among the categories shown. The high cost of BTM solar derives from its small scale and expensive structural and electrical costs. The substantial cost of rebuilding distribution systems to allow two-way flow of power is only partially recovered through interconnection fees and deserves further study. Onsite distributed generation reduces some transmission losses, but the timing of output does not match consumption so much of the output flows back through the distribution system which operates at lower voltages and incurs higher transmission losses than high voltage transmission.

Offshore wind represents the largest proposed investment for the region. It's carbon abatement cost is almost four times the $51/ton benchmark, making it hard to justify economically. Adding offshore wind generation will encounter growing transmission integration limits and costs that will further increase abatement costs. The timing of offshore wind power generation does not match grid loads. After the first few installations are completed, excessive power is produced during very low load periods causing a substantial growth in curtailments after 2025. By 2030, much of this output will be wasted as surplus energy and will disrupt the wholesale market by driving negative pricing. The long term of offtake agreements supporting these projects will negatively impact consumer electric rates and the behavior of the wholesale market for decades.

The carbon abatement costs for grid connected PV projects and onshore wind projects are several times higher than the $51/ton CO2 SCC. Siting for these projects becomes progressively difficult due to land use and public acceptance concerns.

Adding battery storage to recover surplus wind and solar generation is limited by 24 hour cycles and the fact that surpluses occur about 40% of the time. Low utilization of battery storage makes them prohibitively expensive at several times the SCC guideline.

Extending the life of existing nuclear generation is the lowest cost option for reducing CO2 emissions. The introduction of advanced nuclear plant designs after 2030 may be precluded or postponed by long term commitments for solar and wind power which preclude the need for base load generation.

Many other approaches, such as energy efficiency and thermal energy storage may be more cost effective and should be compared in terms of carbon abatement costs.

8.3. Is further expansion of solar and wind generation the best way to reduce CO2 emissions?

New England's solar resource is poor relative to other regions, so investments in solar generation are less productive. Further support for BTM PV in New England is clearly much less cost effective relative to other options.

Solar generation operates less than 15% of the time, while wind generation only occurs about 30-45% of the time. Understanding when this generation occurs relative to the demand for electricity provides the basis for evaluating its value in reducing CO2 emissions. Adding more solar generation only reduces gas plant operation during mid-day periods, while adding large amounts of wind generation creates unusable surpluses during low load periods and has limited impact during high loads when most CO2 emissions occur.

Gas combined cycle plants, which produce most of the targeted CO2 emissions, operate in response to changes in load, to changes in the availability of power from wind and solar generation, and to regional power exchanges. While adding solar and wind generation replaces some of the electricity produced by gas combined cycle plants, it does not significantly contribute to meeting peak loads and it increases the need for grid flexibility to react to large and fast changes in the grid. Gas generation will continue to be relied upon for reliability and flexibility in the absence of any cost-effective large-scale energy storage options.

Further addition of wind and solar will have declining value as surpluses increase, will require larger subsidies, and will create major market problems related to negative pricing.

Committing large, long-term subsidies to new solar and wind generation will discourage other, potentially more effective options. Promoting excess generation and negative pricing will discourage conservation and efficient use of energy.

8.4. What is grid flexibility and why is it important?

The distinction between flexible and inflexible generation becomes more important with increased solar and wind generation. Flexible generation is needed to control load flows within transmission limits, to maintain system frequency, and to respond to rapid changes in loads and in wind and solar generation.

Flexible generation is provided in several ways.

- Gas fired plants and hydro generation with pondage or pumped storage normally operate in response to load changes and to changes in solar and wind resources.
- Some large commercial and industrial customers contract with ISO-NE to reduce loads during extreme peaks or emergency conditions.
- Some operating gas fired plants can increase load quickly (spinning reserve) to address contingencies such as loss of a large generator or major transmission line, and during periods when renewables increase or decline rapidly while loads are changing.
- Other ancillary services provided by a variety of generators include frequency control and fast start capability allowing response to rapid, unforeseen changes.

As more solar and wind generation is added to the grid, more flexible generation will be required to address their variability. This increases CO2 emissions by increasing the operation of gas combined cycle plants and causes them to operate less efficiently at part load and with many startups and shutdowns. This effect is not modeled for this report but deserves further study to understand limits to carbon emissions reduction.

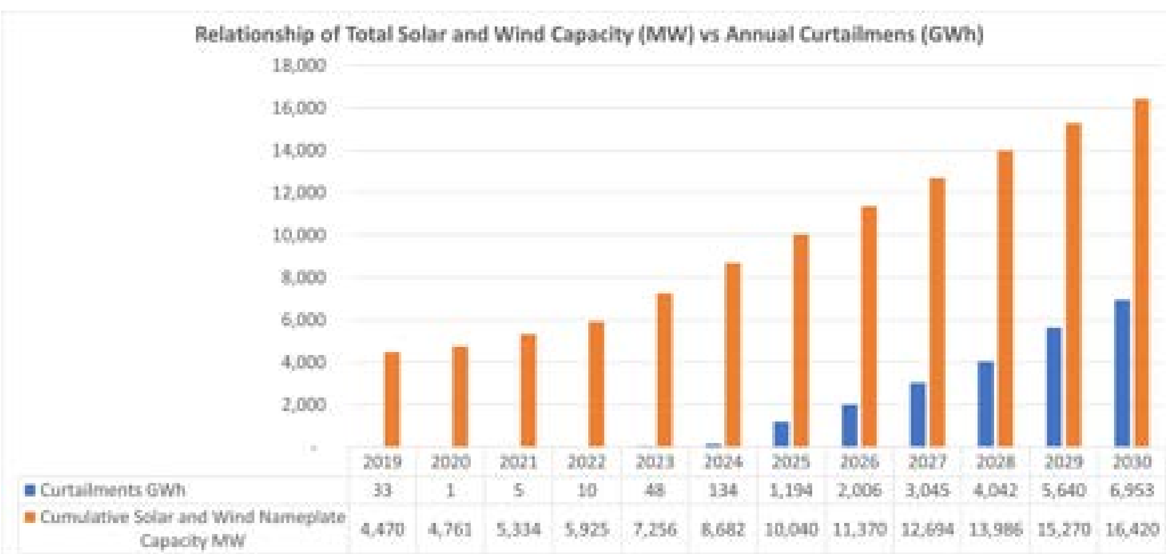
Inflexible generation consists of nuclear, wind, solar and some other generators that are unable or unwilling to change their output to follow changes in system loads. These generators typically have very low variable fuel and operating costs. Nuclear plants encounter technical and regulatory challenges when they shut down and restart. Some solar PV plants can suffer damage to inverters when they have to reduce output. These plants either operate whenever available or have to be curtailed (reduce output or shut down) when they are not needed. Curtailment reduces the annual production of a generator, requiring recovery of capital and fixed O&M through less generation. This effectively increases the $ per kWh recovery of capital and fixed operating costs, which increases the cost of the required subsidy to support carbon free generation, also increasing carbon abatement cost.

8.5. What are the consequences of installing too much wind and solar generation?

As more solar and wind generation is added over the next few years, we encounter practical limits as more energy is wasted when inflexible generation exceeds grid needs. This wasted energy is expensive and can disrupt the wholesale energy market when the effect of subsidies causes negative pricing.

Surpluses, which currently occur rarely, increase as more wind and solar generation are installed. As shown below in Figure 72, the amount of wasted energy from curtailments rises sharply after total renewable generating capacity reaches 9-10 GW in 2024. Current energy policies supporting new solar and wind installations will impact how much energy is wasted as surpluses increase. Note this chart shows curtailments as energy in GWh, while cumulative installed solar and wind capacity is in MW.

Figure 72 Annual Energy Curtailments vs Installed Solar and Wind Capacity



	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Curtailments GWh	33	1	5	10	48	134	1,194	2,006	3,045	4,042	5,640	6,953
Cumulative Solar and Wind Nameplate Capacity MW	4,470	4,761	5,334	5,925	7,256	8,682	10,040	11,370	12,694	13,986	15,270	16,420

Regional power exchange can impact surpluses. Historic 2019 patterns are used to model purchases from Canada and New York, and it is assumed no power is purchased from New York when there are surpluses. Managing regional power exchange to reduce wasted surpluses is being studied by ISO-NE and others. However, similarity in demand and resource variations in adjacent regions limits the ability to export surplus generation.

Electricity from solar and wind generators is much more expensive than from gas combined cycle plants. Increasing subsidies for solar and wind generation will be paid for by higher electric rates and taxes. State renewable portfolio standards (RPS) require distribution companies to procure an increasing amount of renewable generation each year for their customers. The value of clean energy certificates changes to address the economics of new installations which become more expensive as siting constraints are encountered, and in response to changing natural gas prices. As incremental investments in new solar and wind capacity becomes less efficient due to growing surpluses, the magnitude of clean energy credits charged to consumers increases to cover the rising cost of wasted energy.

State RPS programs need to be reviewed to address this effect and to assess the cost of increasing clean energy credits and their associated consumer electric rate impacts. The increased cost to consumers from growing curtailments estimated to exceed $1.4 billion per year in 2030. Assuming about 7.5 million ratepayers, that approaches $500/yr per ratepayer.

8.6. How will increasing solar and wind generation impact consumers?

It is important to recognize how consumers pay for the combined costs of wholesale electricity and subsidies. Existing gas combined cycle plants currently set regional energy prices most of the time through a competitive market at about $20 to $40/MWh based on their fuel and operating costs. The higher cost for new wind and solar generation (ranging from $70 to over $335/MWh) is covered mostly by subsidies that operate outside of the wholesale electricity market. These subsidies are paid for by consumers through taxes and higher electric rates.

Figure 73 below shows the changing relationship between energy subsidies and energy market value.

Figure 73 Changing Energy Subsidies and Market Value

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Value of Curtailments $M	7	0	1	2	10	27	239	401	609	809	1,129	1,391
Total Subsidies $M	1,062	1,170	1,321	1,468	1,853	2,387	2,650	2,948	3,224	3,488	3,699	3,865
Total Market Revenue $M	3,796	3,905	3,720	3,694	3,639	3,643	3,026	2,822	2,623	2,468	2,264	2,158

Market revenue is modeled as the hourly price of wholesale electricity times the amount of energy produced by all generators in operation during that hour. The cost of subsidies is estimated based on the difference between solar and wind production cost and the cost of gas combined cycle generation set at $4/MMBtu gas in 2020 dollars. The additional costs of transmission and distribution improvements needed to enable the growth of wind and solar generation are not included.

The impact of these subsidies on consumer electric rates varies widely by state and by distribution company. The projected costs represent about a 50% increase in the portion of consumer electric bills impacted by wholesale pricing, energy credits, and state mandated energy purchases. This assumes that subsidies are fully effective in supporting these investments.

The cost of wholesale electricity becomes a shrinking portion of the electric bill. Lower wholesale prices will be offset by

- higher state-mandated purchases of clean energy credits that will reflect wasted energy from surpluses and declining revenue to solar and wind installations
- state mandated offtake agreements with offshore wind projects that cost several times the cost of displaced gas fired generation
- increased transmission costs to integrate remote generation, including offshore wind
- higher distribution costs to support growing BTM PV installations if not covered by interconnection fees

The combined effect of these increases is expected to be much larger than the effect of lower wholesale pricing reflecting the major projected growth of subsidies.

Electric rates will change unevenly by state and subsidies are implemented. States that are implementing less aggressive RPS and clean energy payments would see lower rate increases. Customers of public power organizations may not be required to participate in expensive offtake agreements with new offshore wind projects and may be subjected to lower costs for renewable energy in their bills.

The uneven distribution of costs contradicts the fact that any potential global benefits in reducing the impacts of climate change are shared evenly.

8.7. How important is gas supply and gas generation to grid operations and to decarbonization?

Gas combined cycle plants provide both reliable generation to meet peak loads and flexibility to connect variable loads with inflexible generation. Reliability challenges from very high loads or loss of other generation are normally addressed by simple cycle combustion turbines and older steam units that operate rarely during such events. Gas supply limits during severe winter periods require the operation of some combined cycle plants on oil firing, and the operation of older oil and gas fired steam units that can run during those conditions.

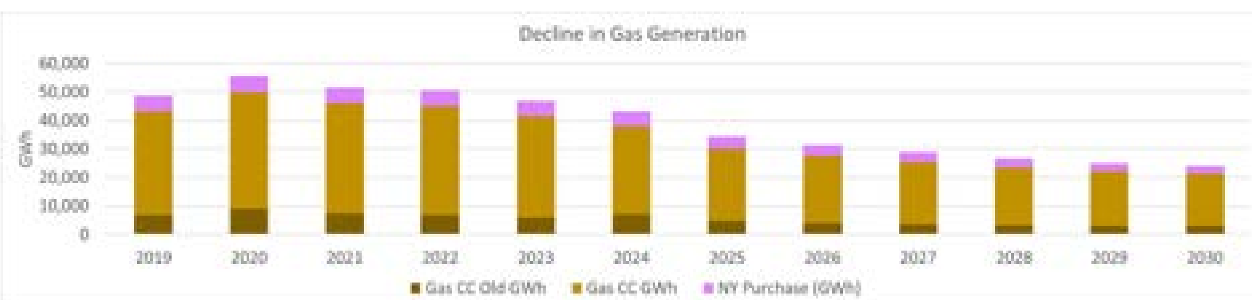
Most of the existing gas generating capacity will be needed through 2030 to meet evening peak loads despite major increases in solar and wind generation which do not provide reliable peak load capacity. Battery storage can support reliability and flexibility needs, but may increase emissions when their charging increases the need to operate gas or oil fired plants.

The regional wholesale price of electricity, subject to some locational variation, is currently set most of the year by gas combined cycle plants. Wholesale gas prices rise when less efficient gas combined cycle plants, paying higher spot market prices, operate during periods of high loads and when solar and wind generation are low.

Higher solar and wind generation results in larger rapid changes in their aggregate output. As solar generation declines each evening, loads are increasing to peak levels, requiring a lot of responsive generation. Combustion turbines are the most economical provider of fast response generation in combined cycle and simple cycle configurations.

A certain amount of gas combined cycle generation is needed to maintain control of regional and local power flows given limitations of transmission capability. This requires gas generation to operate even when loads are low and when solar and wind generation are high, and even during surpluses. Some operational needs, such as voltage and frequency control, may be provided increasingly by the installation of advanced design inverters associated with new solar and wind generation, battery storage and high voltage conversion for large transmission lines. The need to continue to use gas generation during surpluses limits the ability to achieve decarbonization targets.

Figure 74 Decline in Gas Generation



Adding wind and solar generation after 2024 has a declining effect on reducing gas generation shown in Figure 74 for three reasons:

1. The minimum requirement for flexible generation persists even when partially offset by BES.
2. Increasing solar generation only impacts mid-day loads.

3. Much of increasing wind generation exceeds needs during low-load periods and is only available intermittently during high load periods.

8.8. Can we rely on battery energy storage systems to reduce wasted energy from surpluses and curtailments?

Battery energy storage systems can be effective in adding reliability and flexibility to remote locations where transmission and other generation are limited. Batteries are used widely to provide reliable backup power for short periods to critical loads that require more reliability than provided by the power grid. They are often combined with backup generators which provide less expensive energy for longer periods after a battery discharges.

Using batteries to provide reliability has little effect on CO2 emissions. Most of the generating capacity that provides reliability during extreme loads, major outages, or other unusual events rarely runs and contributes little to annual CO2 emissions. The economics of reliable capacity are represented primarily as the cost of capacity in $/kW installed. Utility practice has historically focused on installing or retaining generation that has the lowest initial and fixed costs, since fuel and variable costs are not significant when these generators are used infrequently.

Using battery storage to obtain market arbitrage, charging when energy is cheapest and discharging when it is more expensive, can add commercial value to the facility, but is likely to increase CO2 emissions. When a battery installation charges in the absence of surplus wind or solar generation, it adds to the system load which normally increases the operation of gas combined cycle plants. Since the battery system discharges only about 85% of charging energy, it effectively increases related CO2 emissions by almost 18%. Therefore, operating batter storage for arbitrage should not be considered a decarbonization option except when it displaces higher emission gas simple cycle plants, or older steam plants during extreme events which occur infrequently.

Using battery storage to recover surplus wind and solar generation shifts the emphasis in economic analysis from capacity to energy. Comparing costs on an energy basis as $/MWh makes utilization more important. According to US EIA estimates, battery storage can be installed at a cost of about $1300/kW with a fixed annual cost of about $28/kW per year. Applying typical regulated utility financing costs results in total fixed costs for capital recover and operating costs at about $200/kW per year. If the plant discharges 4 hours every day, it could operate about 16.5% of the year at its design capacity allowing for some maintenance. This results in an annual cost of about $140/MWh per unit energy discharged, not considering the cost of charging energy. If opportunities to reduce CO2 emissions by charging with surplus solar and wind energy occur only half the time, that doubles the production cost to $280/MWh since the same annual costs must be recovered with half of the energy production. The energy economics of battery storage are therefore highly sensitive to utilization.

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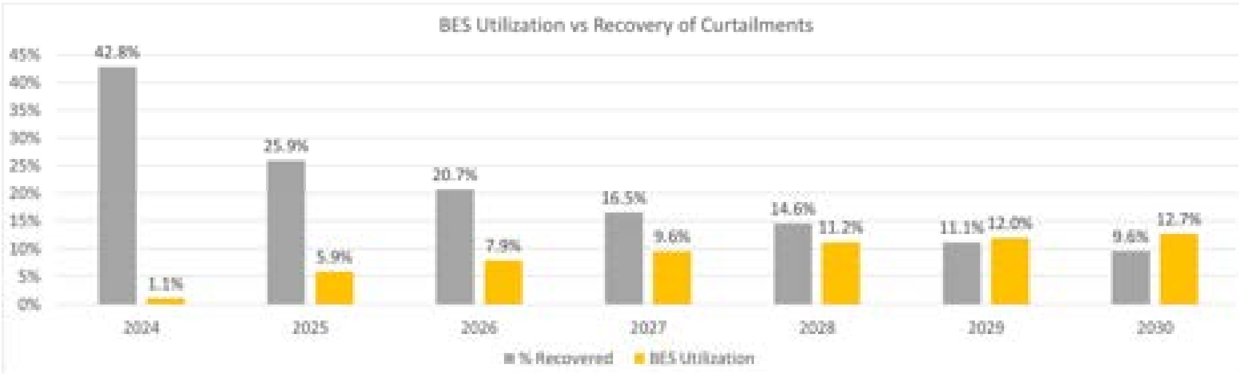


Figure 76 show the changing carbon abatement cost of reducing CO2 emissions by using 600 MW of BES to recover surplus energy. BES utilization increases as more wind and solar generation is installed and as surpluses increase.

Figure 75 BES Utilization with Increased Curtailments

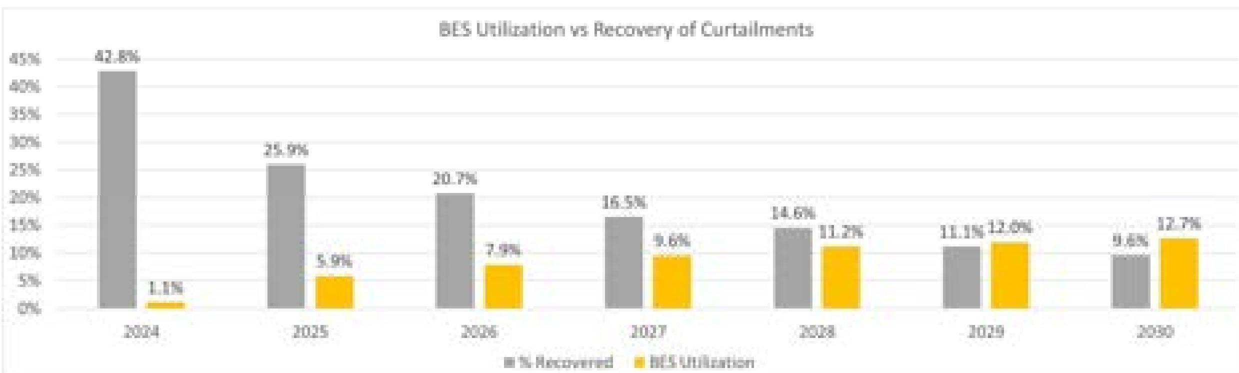
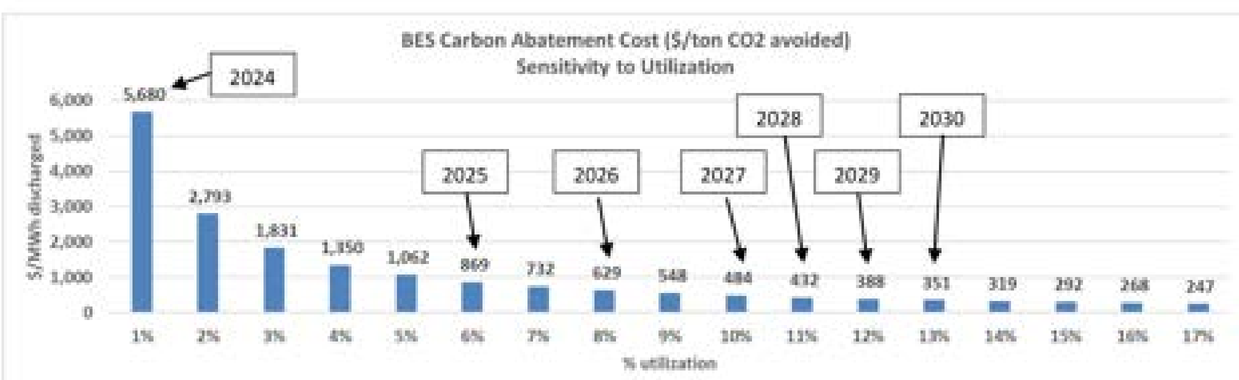


Figure 76 BES Carbon Abatement Cost vs Utilization



Based on 2020 dollars; BES cost does not include the cost of charging energy

As BES utilization increases, carbon abatement cost decreases slightly but unused surpluses increase dramatically. Conversely, adding more battery storage to recover more surplus energy reduces utilization, increasing carbon abatement costs.

8.9. Do we still need to rely on higher-emitting oil and coal power generation?

Oil and coal power generation capacity contributes to grid reliability but does not contribute significantly to CO2 emissions. During some winter peak loads driven by extreme cold, limited regional gas supply capacity is diverted to building heating needs, disabling much of the gas generation capacity. During these periods, gas power generation is limited to very expensive pipeline gas, some of the imported LNG, and the limited ability for some gas fired units to switch to burning oil. Aging oil and coal fired steam units may run for short periods during these conditions.

Many of these aging oil and coal fired steam generators currently survive financially based on receiving capacity payments. Some are likely to retire when they encounter major equipment failures requiring expensive repairs, or when they are confronted with further environmental restrictions that increase costs substantially. Such retirements could threaten future reliability needs, especially if electrification increases peak loads. Solar generation reaches seasonal minimums in early winter, and wind generation only occurs 30-40% of the time. Retirement of aging steam plants may require installation of new simple cycle combustion turbines that can operate on oil when gas supply is interrupted, and the addition of oil firing capability and oil storage to some capable existing combustion turbine sites.

If aggressive electrification of building and transportation occurs beyond 2030, winter peak loads will increase requiring the installation of new oil fired capacity unless there are improvements to regional gas supply.

8.10. Do state decarbonization policies contradict regional power industry deregulation objectives?

New England currently benefits from one of the most efficient, economic and reliable power grids in the country. This is the result of large private investments in gas generation that responded to market needs, industry deregulation, declining gas pricing, and increasing environmental pressure on emissions from oil and coal generating plants. Privatization and deregulation were implemented to support innovation in response to changing markets and to shift the risk of new projects from ratepayers to private investors.

This has resulted in private investment over $16 billion since the 1990s to install the current fleet of gas combined cycle plants. The current owners/investors of these plants are important participants in the regional grid representing effective response to changing competitive markets as intended by deregulation. Their ability to survive as profitable business operations is threatened by proposed decarbonization initiatives that seek to minimize the operation of gas fired plants. Their survival over the next decade is critical to the adequacy and reliability of the grid.

Almost all of the proposed investment in new generation capacity through 2030 responds to is state energy policy subsidies and regulation. Private investment in new generation projects is no longer responsive the needs of the power grid unless reflected in state policies. States require distribution companies to invest directly in solar, wind and battery projects, and to contract directly with offshore wind projects and pass the extra costs to their ratepayers. Market revenues will decline as larger and more frequent surpluses evolve with negative pricing. There is still private investment and competition, but investment in new generation is no longer responding to regional wholesale energy and capacity markets as intended by deregulation.

Competition in the wholesale energy market is shifting from the cost of gas generation to the effect of subsidies driving negative pricing for wind and solar generation as shown below in Figure 77. This shift to subsidies represents the socialization of roughly 75% of the regional costs of power generation by 2030.

Figure 77 Market Value Decline

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Value of Curtailments $M	7	0	1	2	10	27	239	401	609	809	1,129	1,391
Total Subsidies $M	1,062	1,170	1,321	1,468	1,853	2,387	2,650	2,948	3,224	3,488	3,699	3,865
Total Market Revenue $M	3,796	3,905	3,720	3,694	3,639	3,643	3,026	2,822	2,623	2,468	2,264	2,158

State policy dominated changes to the grid will require increasing interventions by ISO NE, including adjustments to capacity markets, expensive transmission improvements, and adjustments to the exchange of power with other regions.

This shift from competitive market operation to the dominant influence of subsidies raises the question of whether state decarbonization initiatives interfere with the operation of a fair competitive market as required by FERC oversight, and whether the effects of these subsidies contradict the concept of preventing excessive market power from unfairly impacting competitive markets.

8.11. How will electrification of building energy and transportation impact decarbonization initiatives?

Electrification of buildings and transportation will increase electric loads and CO2 emissions. ISO NE has included these effects in their load projections through 2030. In the longer term, extended growth of electric building heating systems and vehicle charging loads is likely to increase peak loads and will likely require increased operation of gas and oil fired generation. Some of these increases in electricity demand can be mitigated by scheduling building energy and vehicle charging loads away from peak periods. Work is underway to develop a better understanding of these effects, especially the timing of new loads for charging stations and heat pumps.

Since electrification initiatives are intended to support decarbonization, the unsubsidized carbon abatement costs for these electrification initiatives should be evaluated, including the effects of increasing power industry carbon emissions.

8.12. How long will new solar and wind generation installations last?

The expected life of PV systems is about 15-20 years, after which panels and inverters need to be replaced with new equipment or removed, requiring the disposal of a large volume of solar panels. Since PV technology changes rapidly, it is difficult to repair or replace components when they fail because hardware designs have changed. Panels degrade leading to gradual loss in output. Many installations do not invest in spare PV panels and inverters, which may not be replaceable with new components with different electrical characteristics. Current subsidies will have to be extended to support investment in repowering or for replacing aging systems. Owners of PV installations will have to set aside funds for the cost of removing and disposing of PV panels, support frames, inverters, and other supporting equipment. This end-of-life cost is not always considered when these installations are installed...

The expected life of onshore wind farms is expected to be about 20-25 years, and longer industry projections may be optimistic. Harsh marine environments will test the lifetime of new materials and components. The history of existing offshore wind farms has shown major reductions in output over time due to increasing failures and extended time to implement repairs. Remote offshore locations make it expensive to inspect, maintain and repair wind turbine generators. Repowering existing wind farms with new equipment may be limited by the ability to match new equipment with existing towers and electrical equipment. Decommissioning retired windfarms will require dismantling and disposal of large components.

Progressive increases in wind and solar generation will create surpluses and negative pricing that will reduce the market income to these plants, making them increasingly dependent on subsidies. Declining revenue may reduce asset values and shorten the lives of these facilities, discouraging expenditures for repairs and life extension.

8.13. Does support for solar and wind technologies discourage more effective options?

Adding solar and wind generation to the grid creates long term commitments to produce energy at times which do not match the timing of load requirements. Surpluses and lower energy pricing for this subsidized energy makes it more difficult for other forms of generation to continue to operate, and especially difficult for any new investment in other technologies seeking energy revenue from the wholesale energy market. Lower energy pricing discourages conservation, innovation and competition. Negative energy pricing encourages wasteful use of energy.

Current policies shift financial incentives for new projects away from market pricing to state subsidies. As a result, only new projects that are subsidized by state policies are proceeding, and any other investments are discouraged.

8.14. Should we support existing and new nuclear generation?

Extending the lives of existing nuclear power generation plants at Millstone and Seabrook is a very cost-effective way to reduce CO_2 emissions. These plants incur substantial fixed operating costs needed to maintain the high levels of design and operational safety required by the Nuclear Regulatory Commission (NRC). These annual costs may exceed wholesale pricing when gas prices are low. Recent increases in natural gas pricing have reduced the need for these plants to receive state subsidies based on carbon free production. Allowing these plants to receive clean energy credits makes them more financially secure even when gas prices are low. Recognition of the large amount of carbon displacement, and the low carbon abatement cost for their life extension justifies close attention by policy makers to make their continued operation economical subject to nuclear regulatory requirements.

Shifting ownership of nuclear plants to a regulated utility or to a public utility could improve their economic outlooks. These forms of ownership provide lower cost capital and have a longer range planning horizon that supports life extension and license extension initiatives, which are more difficult for private owners concerned with short term uncertain market conditions. The expectation of lower energy revenue and negative energy pricing resulting from energy surpluses will make it difficult for private ownership to justify investments. Public or regulated ownership could justify higher short term costs and investments as part of approved long range plans.

Current nuclear plant designs favor base load operation which becomes a liability when more variable wind and solar generation are added which effectively eliminate base load and introduce subsidies. Advanced nuclear technology capable of flexible operations has the potential to replace gas combined cycle plants in the future if cost targets are achieved and if regional support is established for siting, permitting and licensing new nuclear units.

8.15. Should ratepayers be given a better understanding of future costs, long term commitments and rate impacts?

New England electric rates have doubled over the last decade and are now among the highest in the country. Subsidies for solar and wind generation and wind generation are over $1.3 billion per year, split between taxes and electric rates, increasing with new installations. These subsidies are projected to grow to almost $4 billion in 2030. These estimates exclude additional costs of transmission and distribution systems which are also passed along to consumers. Most ratepayers are currently not aware of why their rates have increased, or of the future rate impact of new solar and wind generation additions.

Distribution companies should conduct rate impact studies for proposed state decarbonization initiatives during a public review period prior to such commitments.

There are many misrepresentations that renewable power generation is economical without subsidies in New England. (Phelps, 2020). Lobbying groups, such as in the article by Vote Solar referenced above, inaccurately claim “the enormous befit of local solar power to everyone in New England.” Rooftop solar systems are among the most expensive and least effective investments to reduce gas power generation CO2 emissions.

Consumers deserve an accurate accounting of how additional costs related to decarbonization impact their rates and taxation. Electric bills should explain what causes rates to increase, including specific costs related to decarbonization.

8.16. Should each state have different energy policies and subsidies?

The New England power grid evolved through progressive responses to changes in electricity use, technology innovation, shifting availability and cost of fuels, increasing environmental restrictions, and changes in policies driving deregulation and subsidies for decarbonization.

Deregulation of electric power generation shaped a competitive wholesale market where private investment pursued less capital-intensive gas projects and heavily subsidized renewables. As a result, New England enjoys some of the lowest cost wholesale electric prices in the US set by efficient gas combined cycle plants, but consumers pay roughly twice as much for electricity to pay for clean energy credits, net metering, and transmission/distribution improvements.

New England states currently provide among the strongest subsidies in the U.S. for wind and solar generation in the form of clean energy credits and through state regulatory mandates.. Generators in one state offering higher clean energy credits obtain an advantage over similar generators in other states. Lower regional wholesale pricing impacts all generators in the region through a single market.

State subsidies, such as rising renewable energy credits tracking annually increasing portfolio standards, have a larger effect than tax credits and accelerated depreciation. State public utility commissions approve the assignment of higher costs to ratepayers for transmission and distribution improvements needed to enable new wind and solar projects.

State based incentives shape the location and timing of new projects with limited consideration for regional distribution of loads, transmission and generation. Offshore wind development will be challenged by transmission integration limitations. States offering larger energy credits can cause the installation of less cost effective projects with higher carbon abatement costs, while better options may exist in other states. Conversely, more cost effective projects could be discouraged in states with lower subsidies.

Modeling regional grid behavior as a single system provides a simple, effective view of how generators and loads interact. It is more difficult to model the interaction of state specific clean energy credits on a single regional wholesale market.

The Social Cost of Carbon has a global basis, rather than a local one. The effectiveness of decarbonization initiatives at the state level needs to consider the context of global changes. The International Energy Agency projects that global energy-related CO2 emissions are increasing by over 1,500 million metric tons (4.8%) in 2021. (International Energy Agency, 2022) Expansion of economies in developing countries are expected to lead to overall increases in the use of fossil fuels. This provides an important context for considering whether an investment of over $61 billion in new solar and wind generation to reduce CO2 emissions by about 13 million tons per year in 2030 is cost-effective, given the likelihood that global targets for CO2 reductions are not likely to be achieved.

When a single distribution electric utility participates in a long term power purchase agreement for an offshore wind project, the higher cost of energy is assigned to one set of ratepayers while potential benefits are distributed globally.

The uneven distribution of costs and benefits, and the fairness of individual state subsidies should be carefully examined by FERC to determine if this supports the operation of a fair competitive market that encourages innovation and competition. The concept of state decarbonization policy driven investments that negatively impact regional markets should be evaluated at the national level.

Federal and state subsidies for renewable power generation have had a negative impact on the reliability of some power grids, such as ERCOT. According to American Power, a trade organization that advocates for coal fueled electricity, the low marginal cost of subsidized wind power depressed market prices to the point where over 5,000 MW of conventional generation were retired in Texas because of the resulting drop in market revenues (Power, 2020). Federal investment and production tax credits, and accelerated tax depreciation, have had the effect of covering over one third of the cost of building and operating solar and wind facilities.]

ISO NE should be given a stronger role in reviewing proposed decarbonization policies to evaluate impacts on future adequacy and reliability requirements.

The use of a broader, uniform regional or national incentive in the form of a carbon tax or clean energy credit has been proposed as a more equitable replacement for other subsidies. A long term, consistent incentive will allow other more cost-effective decarbonization solutions to compete. This approach would not provide the focused, intensive support needed for wind and solar technologies to expand as currently planned. Implementing a national or regional clean energy credit or carbon tax would require justifying a Social Cost of Carbon as a policy basis, subject to considerable review and broad agreement, which currently appears unlikely.

8.17. Is the "Best Science Available" to support Net Zero targets sufficiently supported?

Net Zero decarbonization targets are established based on what is referred to as the "best science available," represented by the IPCC's interpretation of climate science, and associated climate modeling. The power industry has historically applied a rigorous standard to evaluate investments in power generation in response to the requirement that the most cost-effective options are implemented. Federal and state agencies overseeing environmental compliance need to justify regulations requiring additional cost to achieve environmental objectives such as the installation of expensive equipment to reduce air emissions, wastewater discharges and solid waste production.

The interpretation of climate science by IPCC and the usefulness of climate models in making predictions has encountered major challenges. Many of these challenges have been pushed aside by aggressive climate advocacy without careful analysis and debate.

Now that very large investments are proposed with high ratepayer and tax impacts, a more rigorous examination is needed to determine whether "the best science available" is sufficiently reliable to justify taking large financial resources away from other important societal needs. The risk that the cost of subsidies will exceed the value regional decarbonization represents a precarious balance between allowing environmental harm versus causing economic harm.

A formal, thorough, independent and objective review is needed to address specific challenges to the interpretation of climate science as the basis for policy.

8.18. How do we provide an independent review of decarbonization plans?

There is extensive history and experience with the formal due diligence review of large energy investments required by lenders, investors and other stakeholders.

Key aspects of independent review of an energy project include:

- Defining the full scope and characteristics of proposed installations
- Compiling and reviewing supporting documents and data
- Determining the adequacy and completeness of cost estimates, schedules, financial projections and implementation planning
- Clarifying the sources and uses of money needed for implementation
- Confirming that risks and uncertainties are adequately identified and addressed
- Confirming compliance with laws and regulations, adequacy of agreements and commitments
- Confirming the qualifications and experience of key participants
- Projecting the life cycle operation, costs and revenues in competitive markets.

A review team would consist of independent experts in technology, markets, economics, science, and policy excluding individuals who could be significantly impacted by the outcome of the review.

The outcome of the review would be a series of reports and recommendations progressively reviewed with stakeholders. Areas of disagreement, uncertainty and need for further work would be determined. The information collected and supporting reviews and analyses would be documented as a reference and guide to government leaders, the public and stakeholders.

A key finding from the review would address whether an objective understanding of climate science, climate modeling and their uncertainties support the basis for an SCC, and whether it is likely that the large proposed investments and their impacts will have the projected effect on improving future climate impacts. This could support a major re-evaluation and redirection of state and federal energy policies.

8.19. What other technologies and innovations should be encouraged?

Many innovations are not rewarded by current policies which focus subsidies on solar, wind and battery storage. Policies such as net metering for BTM solar provide free energy storage services and discourage investment in onsite energy storage. Growing periods of very low or negative pricing can discourage energy conservation and may drive inefficient uses of electricity such as electric resistance heating when prices are very low or negative.

The large scale production of hydrogen storage has been studied extensively over many decades when high energy prices drove interest in a hydrogen economy. Large capital investments and replacement of much of our energy infrastructure make this option impractical and prohibitively expensive relative to current power generation costs. Work is underway to confirm this.

Carbon sequestration is much more expensive than most other decarbonization options.

Use of biofuels at a larger scale has been proposed. Biofuels have been studied for decades and found to be very expensive relative to conventional fuels. Further investigation of the carbon abatement costs of applying this technology is needed.

Changing how electricity is used would improve the efficiency of grid operations and reduce carbon emissions. Key aspects of customer behavior include smart grid interfaces that provide market signals and scheduling use of high energy consuming appliances. Changing consumer behavior may entail buying back reliability, which is very expensive to deliver.

Thermal storage may provide much more cost-effective options than storing electricity. Electrification initiatives will increase electrical loads during peak load periods by electric heat pumps and electric car charging stations. Using a thermal storage system with a smaller capacity (and less expensive) heat pump, designed to operate more efficiently outside of extreme temperatures, would shift loads away from peak periods and would reduce total energy consumption by operating during periods when a higher coefficient of efficiency is available. This would provide flexibility to the grid on the load side and could be incented through time-of-day pricing to respond to actual grid costs and values.

Replacing gas combined cycle plants in the future with advanced nuclear power plant designs may be more effective than a transition to wind and solar. A power grid with substantial renewable generation requires flexibility, while current design nuclear reactors are capital intensive and need to operate continuously to recover their investment. So designing a reactor plant that operates continuously to store high temperature heat, tied to a power generation unit that can operate in response to changing loads, is an example of a technology that could replace many gas combined cycle plants in New England after 2030.

9. Conclusions and Recommendations

The work presented in this report demonstrates the application of carbon abatement costs to challenge the overall economic effectiveness of subsidies applied to reduce carbon emissions by increasing solar and wind generation. A simplified but effective method for high level hourly modeling of grid operation shows that the timing of CO2 emissions and solar and wind generation results in practical limits. Adding solar and wind generation has declining value. The concept of an energy transition from gas combined cycle plants to solar, wind and battery storage encounters critical technical and economic limits.

9.1. Technical Limits

The New England power grid has evolved over recent decades in response to the large-scale development of nuclear power generation, changing environmental regulations discouraging coal firing, the availability of inexpensive natural gas, and deregulation of most power generation. Gas combined cycle plants and limited hydro pumped storage facilities currently provide flexibility and control to the system as loads and the availability of other generation changes. Nuclear, wind, solar and some other electric generation are inflexible and have limited capability to respond to changes. Reliability is provided by gas combined cycle plants, simple cycle gas generation and older gas, oil and coal units that operate rarely during unusual conditions.

Installing new wind and solar generation has obvious practical limits that are demonstrated by hourly modeling. Solar generation is limited to mid-day periods and wind generation is available intermittently throughout the day. We are reaching a key technical limit in 2024 after which further expansion of wind and solar generation becomes progressively inefficient, as more unusable surpluses occur during periods when loads are low and when there is too much inflexible generation.

Most carbon emissions occur in the evenings from combined cycle plants that support our highest electric loads. Much of these emissions cannot be reduced by adding solar and wind generation, most of which does not occur in the evenings during high loads. Installing more solar and wind generation results in increasing surpluses with a declining effect on displacing carbon emissions.

Adding battery energy storage has limited and declining effect in recovering surplus solar and wind generation. Battery storage operates on a consistent daily cycle, while surpluses vary substantially in responses to changes in loads, solar and wind generation. A small amount of battery storage can operate over 10% of the time when there is a lot of surplus solar or wind generation. As battery storage capacity increases relative to surpluses its utilization to reduce carbon emissions decreases, limited by timing.

Other technical limits need to be considered, including the ability to find sites that are acceptable from the standpoint of land use and grid interconnections. Declining public acceptance of using large amounts of land for new solar, wind and transmission installations make permitting more difficult and increases project costs. Supply chain limitations can limit the ability to rapidly increase solar and wind generation.

9.2. Economic Limits

Perhaps the most difficult challenge regarding the economics of decarbonization is to balance the economic damage of subsidies with environmental benefits.

The cost effectiveness of decarbonization options can be evaluated by calculating carbon abatement costs for each technology based on modeling the reduced operation of gas fired plants. This approach supports the prioritization of alternative decarbonization investments based on cost effectiveness. The unsubsidized cost of electricity from new wind and solar installations is much higher than the cost of wholesale power from gas combined cycle plants which currently dominate wholesale energy market pricing. The magnitude of subsidies for each type of solar and wind plant can be estimated as the difference between their life cycle costs and the incremental operating and fuel cost avoided when gas combined cycle plants operate less of the time. Dividing the estimated subsidy for each type of plant by the amount of carbon dioxide avoided provides and estimated carbon abatement cost.

An important policy metric is a determination of the Social Cost of Carbon, which is the monetized cost of physical damage resulting from the continued emission of a ton of carbon dioxide every year. This concept is highly controversial and legally disputed, given how important it is to various stakeholders in the energy industry. However, it represents a key economic point beyond which excessive investment does more damage to the economy than its value in reducing environmental damage. Its determination is highly dependent on the ability to project the relationship between human caused emissions and measurable costs of environmental damage. A key issue is whether large regional improvements in carbon emissions are effective while global changes in emissions are not substantially reduced. Also, the details of climate modeling assumptions to support long term projections have been challenged and are very controversial.

Estimated carbon abatement costs for wind, solar and battery storage subsidies surprisingly range from 2 to 15 times the current policy based social cost of carbon. The cost of adding battery storage to reduce carbon emissions ranges from about 7-18 times this value. This raises the obvious question that our current plans to expand solar and wind generation are not cost effective and are likely to cause more economic damage than environmental benefit. This finding suggests that the potential economic damage from rising energy costs and taxation merit further investigation and public debate before additional long-term commitments are put in place.

In addition to regional economic damage from rising energy costs, the effects of large subsidies for wind and solar generation can be very disruptive to the competitive wholesale market. Generators receiving large subsidies such as energy credits and performance tax credits can offer negative pricing to retain some of their value. Extensive occurrence of negative pricing is very disruptive to the wholesale market and reflects the flow of state sponsored subsidies into a competitive market impact extensive private investment. Any plant that needs to operate during surpluses will have to pay to run. Plants needed for flexibility will need additional subsidies. Nuclear, solar, wind and other types of generation that need to operate during negative pricing will receive less revenue each year as surpluses increase. This will result in the need for higher state subsidies through clean energy credits to sustain the business survival of these plants. Plants whose subsidies expire are likely to see a shorter economic life. This could undermine the environmental gains from these investments. If counter-subsidies needed to maintain grid control and flexibility in the face of negative pricing are not properly managed, grid reliability and control is likely to deteriorate with grave consequences.

The magnitude of subsidies that will be required to achieve the projected growth of wind and solar generation dwarfs the wholesale value of energy produced in the regional grid. Subsidies rise from about 20% of the wholesale value of energy to over four times that market. This represents moving from a power generation market based on competition to one that is socialized and supported primarily by subsidies.

The recent policy objectives of privatization and deregulation are contradicted by current state policies that effectively socialize and re-regulate the regional power industry. Deregulation caused a shift to business innovation and short term planning horizons driven by higher cost of capital, competitive markets and a shift of investment risk to private investors. Regulated power generation can reduce innovation by providing guaranteed profit, but encourages longer planning horizons and reduces the cost of capital. Public power provides the lowest cost of capital, the longest planning horizon and possibly the lowest need for innovation. As states provide large subsidies for specific technologies and projects, the opportunity for competition, innovation and free markets to find other effective solutions are discouraged. Uneven distribution of costs among the New England states is likely to be challenged by consumer groups as unfair.

9.3. Recommendations

State energy policies targeting reductions in power grid carbon emissions in New England need to undergo a critical review to evaluate their cost effectiveness and unintended impacts.

1. Each state should produce transparent reports describing how policy initiatives comply with legal requirements for cost effectiveness. An analysis of carbon abatement costs should be presented for a wide range of technology options. Carbon abatement costs should include transmission and distribution changes to support renewable generation. A ceiling on carbon abatements costs should be established based on consideration of a determination of the SCC based on open discussion and public input. The impact of current technology-specific subsidies should be reviewed to determine whether the implementation of other, more cost-effective technologies is being discouraged.

2. Regional studies should be undertaken with ISO NE to evaluate the curtailments likely to result from projected increases in solar and wind generation. The increase of curtailments over time should be considered in projecting carbon abatement costs. Also, the projected occurrence of negative pricing should be carefully evaluated to determine resulting destructive impacts on asset values and longevity of generating resources, potentially impacting future adequacy, flexibility and reliability.

3. FERC should undertake a review of whether renewable energy credits and above-market power purchase agreements with offshore wind and other projects negatively impact fair competitive bidding and investment planning in the wholesale power market. This review should also address the resulting uneven distribution of costs and benefits among states and between regulated and public owned retail electricity suppliers.

4. State RPS targets should be re-evaluated to determine if they should be suspended or redesigned due to declining effectiveness and negative impacts on the wholesale markets. Rapid deployment of additional wind and solar generation will hit an inflexion point in 2024 after which curtailments will grow rapidly with major negative effects.

5. More uniform regional and national energy policy is needed to achieve cost effectiveness and fair distribution of costs and benefits.

6. Immediate discontinuation of subsidies for BTM solar systems should be considered given their extremely high costs and low effectiveness in decarbonization.

7. A comprehensive independent review should be undertaken on behalf of electric customers to determine overall cost effectiveness and rate impacts of regional and state energy policies. Special consideration should be given to carbon abatement costs, curtailments, negative pricing, and overall effectiveness in the context of global efforts and expected outcomes regarding climate. Electric utilities should fully inform consumers on how subsidies flow into their electric rates and taxes.

10. Terms and Abbreviations

BES – battery energy storage

BTM -- behind the meter generation, including power generation equipment that operates on the customer side of a retail meter, such as rooftop PV systems, which can be interconnected to the grid through the meter

capital cost – Amount of investment that must be raised to develop, build and bring a facility to commercial operation

carbon abatement cost – The additional cost incurred by installing facilities to reduce CO2 emissions divided by the amount of CO2 avoided in metric tons. Additional costs are calculated relative to the type of units whose output is replaced by the new facilities.

carbon emissions – CO2 emissions usually measured in tons (2000 pounds) or metric tons (2207 pounds)

cost of capital – The equivalent annual payment, as a percentage of the total financed capital, to pay back investors and lenders after accounting for tax effects.

curtailment -- Forced shutdown of an inflexible generator when it produces energy in excess of regional and local load requirements. Nuclear plants are not curtailed because of their design.

energy policy – The effects of legislation and regulation which impact the production, distribution and use of energy

first year cost – Costs reflecting the value of a dollar projected to the first year when a plant starts operating. First year cost can be the same as levelized cost when inflation or escalation on all cost streams is set to zero.

flexible generation – Power generation facilities that can follow load as requested by a grid control center

gas combined cycle plant – A modern combustion turbine generator firing gas, sometimes able to burn fuel oil, which exhausts into a heat recovery steam generator that drives a steam turbine with a condenser cooling system. Emission control systems are provided to minimize air contaminants. Plant must be connected to a gas supply pipeline, through a switchyard to transmission lines, and water supply unless a more expensive dry cooling system is installed. These plants are designed to operate most of the time to recover the extra investment for efficient energy conversion.

gas combustion turbine plant – A modern simple cycle combustion turbine generator capable of firing gas and possibly oil, with emission controls. The plant must be connected to a gas pipeline and through a switchyard to transmission lines. These plants are very simple, less expensive, less efficient, and intended to operate occasionally during peak periods, system emergencies, or to provide fast response and flexibility when loads are changing rapidly.

grid connected PV – PV systems that connect and provide power into the power grid

hr - hours

inflexible generation -- Power generation facilities that operate whenever available based on their design and much lower variable operating costs relative to other generators. A grid control center can force some to turn off when there is insufficient demand and too much inflexible generation. Nuclear plants in New England normally only shut down for refueling. Wind and solar plants are designed to operate when resources are available; if shut down the resource is wasted. Some hydro units run when there is water flow or have to spill water if shut down.

ISO NE -- Independent System Operator for New England responsible for managing power grid operations and the competitive wholesale market.

kg – kilograms

lb -- pounds

levelized cost – the equivalent annual payment for mixed future increasing cost streams, determined by calculating the present value and applying a representative cost of money which varies by ownership and financing structure

metric ton – 1000 kg or a “tonne”

Net Zero – reducing total CO2 emissions to a level offset by natural processes

older gas combined cycle plant – a gas combined cycle plant built before 2003

older gas combustion turbine – a gas combustion turbine built before 2003

offshore wind (WindOFF) – wind farms located offshore, including wind turbine generators and supporting equipment, connected through a switchyard to a transmission line

onshore wind (WindON) – wind farms located onshore, including wind turbine generators and supporting equipment, connected through a switchyard to a transmission line

operating costs – Annual costs to support operation of a power generating unit. Fixed operating costs include capital recovery, planned maintenance and repairs, salaries, taxes, insurance and other costs to the owner which occur whether or not a plant is operating. Variable operating costs include fuel, consumables, and maintenance resulting from how much a plant is operated.

plant capacity factor - the percentage of total annual electric energy production divided by the maximum or rated output if the plant were able to operate at maximum or rated capacity every hour of the year.

RPS – Renewable Portfolio Standards set by state legislation which require annual increases in the minimum fraction of solar and wind generation sold to consumers by electric distribution utilities.

Social Cost of Carbon (SCC)– The present value of monetized damages resulting from the emission of one additional metric ton of CO_2. This is highly dependent on economic assumptions and the interpretation of climate science and computer modeling to determine projected impacts.

SMR – Small modular nuclear reactor, representing a new generation of smaller reactors designed for prefabrication to reduce construction costs and with advanced safety and operational features. Some can be integrated with energy storage or operational flexibility to be dispatchable.

steam plant – older gas, oil or coal fired plants with boilers that drive steam turbine generators with condensers and cooling systems.

ton – 2000 pounds

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