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ECONOMIC, FINANCIAL and STRATEGY CONSULTANTS

Millstone Power Station:

Providing support for achieving Connecticut's clean energy goals

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Acknowledgments

This Report presents the results of an independent analysis of the value provided to Connecticut and New England consumers from the continued operation of the Millstone Power Station in Waterford, Connecticut.

This study was prepared at the request of Dominion Resources, Inc. ("Dominion"), the parent company of Dominion Nuclear Connecticut, Inc., owner and operator of the Millstone Power Station. Dr. Tierney and Mr. Aubuchon determined and are responsible for all modeling assumptions and data sources used in this report.[1] The report reflects the analysis and judgment of the authors only, and does not necessarily reflect the views of Dominion.

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About Analysis Group, Inc.

Analysis Group, Inc. provides economic, financial, and business strategy consulting to leading law firms, corporations, and government agencies. The firm has more than 600 professionals, with offices in Boston, Chicago, Dallas, Denver, Los Angeles, Menlo Park, New York, San Francisco, Washington, D.C., Montreal, and Beijing.

Analysis Group's energy and environment practice area is distinguished by expertise in economics, finance, market analysis, regulatory issues, and public policy, as well as significant experience in environmental economics and energy infrastructure development. The practice has worked for a wide variety of clients including (among others) energy producers, suppliers and consumers; utilities; regulatory commissions and other public agencies; tribal governments; power system operators; foundations; financial institutions; and start-up companies.

Executive Summary

Connecticut has established bold and meaningful goals to reduce greenhouse gas ("GHG") emissions from the state's economy by 80 percent from 1990 levels by 2050, while also aspiring to do so in large part through more affordable, cleaner and more reliable electric supply.[2] These goals are not mutually exclusive: affordable electricity will be critical to facilitating and encouraging the increased electrification of the transportation and building sectors needed to meet the robust GHG-reduction goals.

Connecticut has made progress toward its GHG-reduction goals over the past few years.[3] The state has shifted most of its coal and oil electric generation portfolio to natural gas, and has also enabled consumers to use energy much more efficiently. Additionally, Connecticut has a significant source of clean, in-state electricity supply located at the Millstone Power Station in Waterford. With two operating pressurized water reactors, Millstone is capable of generating 2,111 megawatts of electricity using nuclear power. Millstone is New England's largest generating station and supplies nearly all (98 percent) of the Connecticut's carbon-free electricity supply.[4] The State's dual goals of decarbonization and affordable electricity require a continued and sustained focus on addressing the emerging challenges within the electricity sector.

This is the context in which we have been asked to examine the value that the Millstone Power Station generating units provide to Connecticut consumers. The report seeks to answer this question: What could happen to Connecticut's electric supply – to Connecticut consumers' electricity costs, to statewide carbon dioxide ("CO_2") and other emissions, and to its dependence on natural gas – if Millstone's generating units were to shut down before the end of their current operating licenses?

To address this question, this report analyzes the performance of the New England region's electric system, with and without Millstone operating as part of the generation mix. And it does so making several conservative assumptions about implementation of current energy and climate polices, all of which would tend to reduce the value of Millstone Power Station.

Specifically, we assumed that Connecticut and the other New England states will be able to fully meet their current energy and climate goals, in terms of adding increasing supplies of renewable energy, contracting for hydroelectric imports from Canada (assumed to be available via the Northern Pass electric transmission project by June 2020), making the economy more energy efficient, and thereby mitigating natural gas price increases. Even with these conservative assumptions, an early retirement of Millstone and the loss of its output would lead to significantly higher power prices and electricity bills for consumers. It would increase in-state GHG emissions. It would increase the state's reliance on plants that burn natural gas, putting additional stress on the local natural gas markets that also supply heating and industrial fuels for customers in the state.

The premature retirement of Millstone would move the state in the opposite direction and delay forward progress on its affordable and clean energy goals.

After modeling the electric system and using the conservative assumptions noted above, our analysis found that a hypothetical near-term retirement of Millstone would have the following impacts over the period between 2017 and 2030 (the period for which we modeled the electrical system with and without Millstone in operation):

Electricity Bill Impacts for Customers:[5]

- **Maintaining Millstone in operation through 2030 provides $6.2 billion** (net present value) in benefits to all New England electricity consumers.[6] This equates to average savings for New England consumers of $536 million per year. If natural gas prices end up being higher than the current outlook, operating Millstone would provide even more value than we report here. (Figure ES-1 shows the year-to-year total consumer costs for electric energy in New England, with and without Millstone.)
- Avoiding a premature retirement of **Millstone station saves the average Connecticut residential electricity customer over $500 through 2030. B**ased on 2015 average residential bills, Connecticut residential consumers would benefit by approximately 2.5 percent on average, each year over this period. If paid in a lump sum at the beginning of 2017, this would be like providing **3.5 months of free electricity** to every residential consumer in Connecticut (with savings for other Connecticut and New England energy customers as well).
- The benefits of Millstone increase over time, and by 2030, annual average energy **prices would be 21 percent higher if Millstone were prematurely retired**, compared to keeping Millstone in operation (See ES-2).
- Given our conservative modeling assumptions, **Millstone's economic value to consumers could be – and likely will be – even higher**. For example, keeping Millstone in operation over the next decades could avoid impacts in ISO-New England's wholesale electric capacity markets; while difficult to estimate, these benefits could potentially be as high as **another $1.5 billion**[7] for New England consumers in the year of a Millstone retirement.

Carbon Impacts and Other Air Pollution Impacts:

- **In-state CO_2 emissions from Connecticut's power plants would increase by 2.2 million metric tons ("MMT") a year**, which would substantially increase the difficulty for Connecticut to meet its goal to reduce GHG emissions by 20 MMT by 2050.[8] It will be hard enough for Connecticut – like other regions – to meet this goal – but maintaining Millstone's operations will keep Connecticut from backtracking. Without Millstone, the state will have to do everything it already hopes to do **plus** take additional measures to mitigate the emissions from the fossil generation dispatched to replace Millstone. These emissions would be substantial and increase the total 2050 GHG reduction goal by 10 percent, with the state needing to reduce GHG emissions by 22.2 MMT instead of the currently planned 20 MMT. (See Figure ES-3.)

- The CO_2 emissions avoided through Millstone's operations are roughly **equivalent to taking nearly 470,000 passenger cars from the road each year**.[9] These would be on top of the 0.5-1.5 million light-duty electric vehicles ("EVs") that Connecticut already anticipates will be required to help meet its interim 2030 GHG reduction targets.[10]
- Under the current nine-state cap on power-sector CO_2 emissions established by the Regional Greenhouse Gas Initiative ("RGGI"), the premature loss of Millstone's carbon-free electricity would **raise regional CO_2 allowance prices by nearly 30 percent** by 2030[11] – contributing to the consumer price increases noted above. (See Figure ES-4.)
- Losing Millstone's output would **increase nitrogen-oxide ("NOx") emissions** from power plants in Connecticut and elsewhere in New England, thus contributing to worsening air quality and health impacts locally. In 2030, Connecticut NO_x emissions could be approximately 2,423 MT, or 38 percent, higher without Millstone.

Natural Gas Market Impacts and Electric-System Reliability Concerns:

- **Without Millstone**, natural gas-fired electric generation would rise **to 58 percent of all regional supply by 2020** and remain above 50 percent through 2030 – even as other imports and renewables come on line as assumed. By contrast, with Millstone's output, natural gas fired electric generation would account for 45 percent of generation by 2020 and only 38 percent by 2030. The premature retirement of Millstone – the region's largest power station and one that runs on a fuel other than natural gas – could increase electric sector reliability challenges, particularly during the winter heating season when New England's gas demand is greatest. This trend towards greater reliance on natural gas is the opposite of what the region's grid operator and the Connecticut officials have said is needed to address both electric-system cost and reliability issues.[12] (See Figure ES-5.)
- Increased demand from incremental gas-fired generation could lead to a **51-percent increase in the winter wholesale prices of natural gas** as measured at the Algonquin City Gate (which serves the majority of New England customers)[13], and **a 17-percent increase in annual average wholesale natural gas prices** for New England consumers by 2030. (See Figure ES-6.)

Thus, even if everything goes perfectly in terms of Connecticut and other states meeting their energy- efficiency and clean-energy goals, our analysis finds that Millstone's operations would provide substantial positive economic and environmental benefits.

But if, for any reason, some or all these objectives and assumptions do not end up as planned or hoped for – that is, if benchmark natural gas prices end up being higher than expected, and/or if new renewables and Canadian hydropower supplies come on line more slowly than anticipated, and/or if electricity demand is above forecasted levels (as could occur with faster-than-expected adoption of electric vehicles) – then the premature loss of the Millstone Power Station would make it much more difficult and costly for Connecticut to meet its fundamental energy and environmental goals.

Losing Millstone during the 2017-2030 period would require, in the near term at least, that its generation be replaced by a mix of new and existing gas-fired resources plus imports from neighboring regions – thus worsening local air pollution and putting pressure on in-state GHG emissions and the region's carbon cap. Alternatively, replacing Millstone's carbon-free generation would require up to an additional 7,000 megawatts ("MW") of onshore wind, over and above the total amount (5,800 MW) already assumed to come on line in New England by 2030 in our base case.

Our analysis led us to conclude that Millstone's continued operation is key to enabling Connecticut to stay on track in its clean energy, climate and affordable-energy goals.[14] At best, maintaining Millstone will bolster Connecticut and the region's electric system as it transitions toward more renewable energy. At worst, maintaining Millstone's operations provides a valuable, effective and efficient insurance policy in helping Connecticut to remain focused on its goals of "lowering energy bills and improving the state's competitiveness."[15] It also helps to avoid the addition of new gas-fired generating units that could exacerbate potential stranded cost problems in the years to come, as the region transitions toward much deeper decarbonization of its electric grid.

Either way, Millstone's electric supply provides substantial value to Connecticut's consumers and to the state's economy.

Figure ES-1: Electric Energy Costs for New England Consumers, With Millstone Versus Without Millstone (2016-2030)

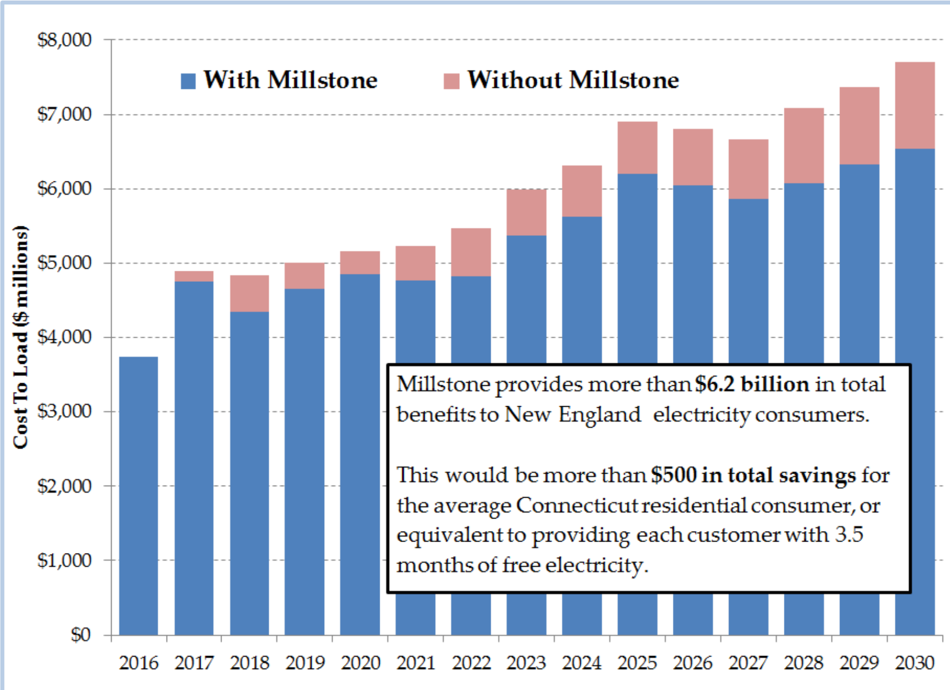


Figure ES-2: Average Wholesale Electric-Energy Price in Connecticut With Millstone Versus Without Millstone ($/MWh) (2016-2030)

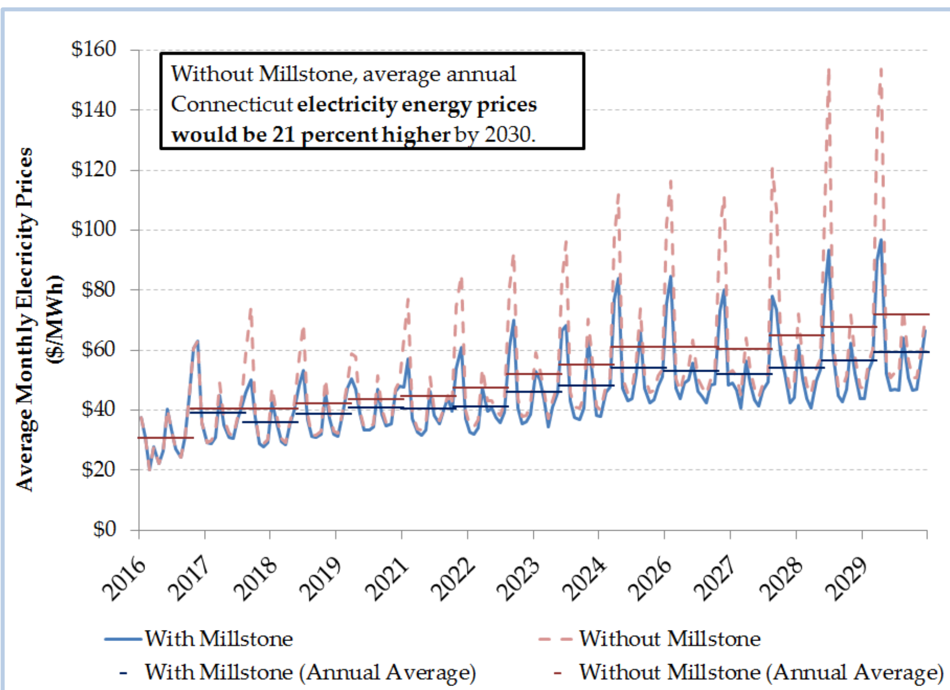


Figure ES-3: Connecticut CO_2 Emissions With Millstone Versus without Millstone (2016-2030)

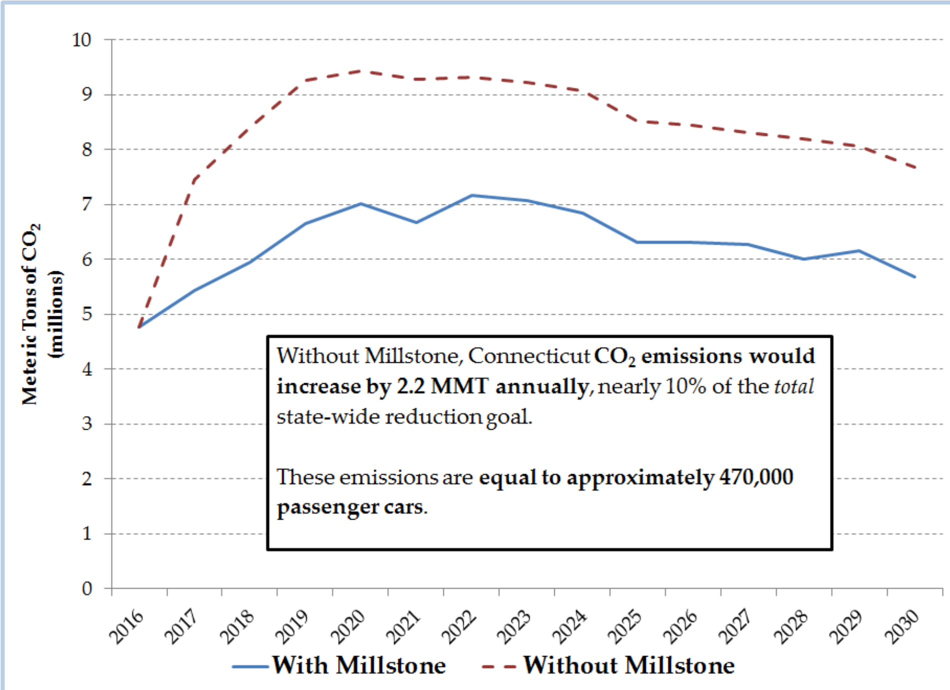


Figure ES-4: Regional CO_2 Emissions, With Millstone Versus Without Millstone (2016-2030)

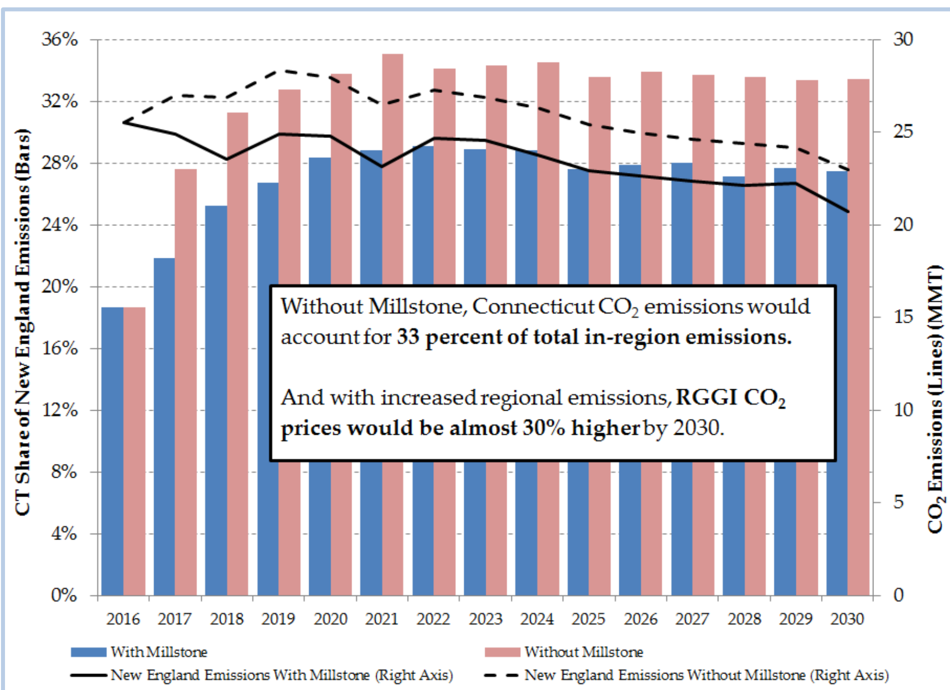


Figure ES-5: Natural-Gas-Fired Generation as Percentage of New England Total Electricity Generation, With Millstone Versus Without Millstone (2016-2030)

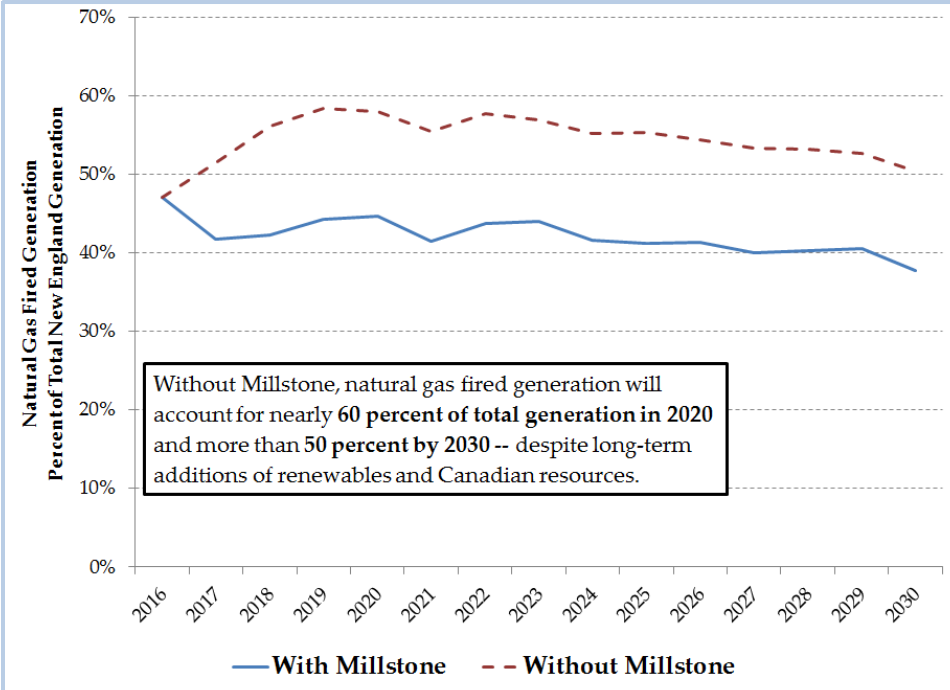
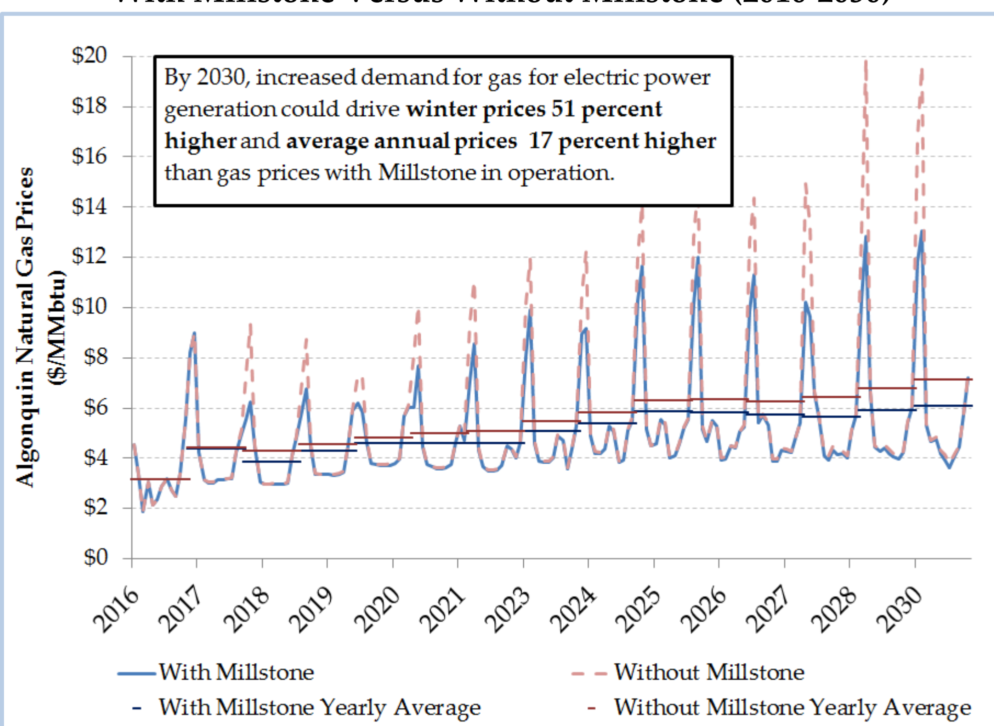


Figure ES-6: Natural Gas Prices (Algonquin Hub), With Millstone Versus Without Millstone (2016-2030)



Background: Connecticut's Clean Energy and Climate Policy Context

The State of Connecticut has taken many steps in recent decades to reshape the energy systems serving the state's households, businesses, and economy. Since 2000, coal-fired generation has dropped from 10 percent to 2 percent of total supply, and oil-fired generation has dropped from 20 percent to 1 percent. These changes have helped to reduce emissions from the power sector.[16]

Compared to the other 49 states, Connecticut now has the fifth lowest carbon emissions per person[17], ties for third place in energy productivity (i.e., the amount of energy used per dollar of economic activity)[18], and is the eighth lowest in terms of the carbon intensity of its energy system.[19] Connecticut's electricity production accounts for only 20 percent of total in-state carbon emissions – a share that is far lower than in most of the other 49 states.[20]

This has resulted in large part from the significant amount of carbon-free electricity hosted within the borders of the state, 98 percent of which came from nuclear generation at the Millstone Power Station in 2015.[21] Millstone supplies one-seventh of the region's entire electrical demand,[22] just under half of total Connecticut electric generation, and almost 60 percent of Connecticut consumers' total electricity demand.

Connecticut's clean-energy policy goals have contributed substantially to this progress. Since 1998, when Connecticut adopted its Renewable Portfolio Standard ("RPS") and continuing up through the State's current efforts to refresh its 2013 Comprehensive Energy Strategy, Connecticut policy makers have taken a leadership role in promoting clean energy and clean electricity.

These policy steps have included the following initiatives:

- Promotion of increasing electricity supplies from renewable energy, with at least 23% of power using renewable energy by January 1, 2020.[23]
- Statutory commitment to reduce economy-wide emissions of GHG by 80 percent by 2050, relative to 2001 levels, with renewables supplying 75 percent of total power generation by 2050.[24]
- Participation as a founding and continuing member of the Regional Greenhouse Gas Initiative ("RGGI"), the regional cap-and-trade program covering CO_2 emissions from new and existing power plants in the nine-state Northeast/ Mid-Atlantic region. RGGI is now undergoing a program review to determine the program's targets and other provisions for the post-2020 period.
- A Gubernatorial commitment by Governor Dannel Malloy to work with other New England states to coordinate regional solutions to the region's electricity challenges.[25]
- Statutory authority for the state to conduct procurements of long-term power supply from providers of certain qualifying electric-energy resources (including

large-scale hydroelectric power from Canada), with the ability to carry out such procurements either alone or in coordination with other New England states.[26]

- A review currently underway by the Governor's Council on Climate Change ("GC3") to examine the effectiveness of existing policies and regulations designed to reduce GHG emissions and identifying new strategies to meet the State's 2050 GHG emissions reduction target and to develop interim statewide GHG reduction targets.[27]

Other recent industry trends have further supported Connecticut's transition to a lower-carbon economy and energy system:

- Relatively low natural gas prices in many years over the past decade, combined with the introduction of nearly 2,500 MW of new natural gas-fired generating capacity since 2000, have led to Connecticut relying on natural gas for 46 percent of its total generation as of 2015.[28] This is up from 12 percent in 2000. Although relatively low gas prices have contributed to gas-fired generation displacing coal- and oil-fired generation (together now only accounting for 3 percent of output in 2015, down from 30 percent in 2000) and helping to reduce air pollution and improve air quality in Connecticut and the Northeast region,[29] this growing dependency on natural gas has nonetheless made electricity prices in Connecticut and New England more volatile since they are closely tied to national and regional commodity prices in natural gas markets.
- Several conventional fossil-fuel power plants have retired in the state since the year 2000.[30]
- Falling costs for renewable technologies have improved the competitiveness of many wind and solar applications, with further innovation and falling prices expected for other renewable generation sources.[31]
- Consumers have shown an increasing interest in managing their energy use, using electric vehicles and "smart" electric devices, and in contracting for low-carbon power supplies, with a variety of approaches being pursued by residential, commercial, and industrial customers; national corporations; public and higher-education institutions; and others.[32]

There are still some challenging countervailing pressures. The low natural gas prices that have helped lower energy prices have also placed financial pressures on the economic viability of existing nuclear power plants in many states and regions which, similar to Connecticut, are served by wholesale markets administered by a regional grid operator (like ISO-New England).

- In New England and most other parts of the United States today, premature retirement of nuclear plants inevitably forces their near-term output to be replaced by increased production by existing gas-fired (carbon-emitting) generation. In the longer term, the existing nuclear capacity may end up being replaced by contracts for renewables, reliance on scaled-up storage systems that are not yet economically competitive or mature, and/or investment in new gas-fired generating resources with asset lives extending beyond 2050. These alternatives all apply long term pressure on the costs of meeting future decarbonization goals.[33]

- Several existing U.S. nuclear plants have already retired or announced their early retirement. Here in New England, Vermont Yankee closed at the end of 2014 due to unsustainable financial challenges.[34] This closure followed upon the retirement of Dominion's Kewaunee nuclear Power Station in Wisconsin for similar reasons in 2012.[35]
- Subsequently, several other nuclear generating units in the Eastern half of the U.S. have signaled their expected early retirements, similarly due to economic pressures in regional power systems (like Connecticut's and New England's) where low natural gas prices set the clearing prices in wholesale energy markets.[36] Examples are: the Pilgrim Station in Plymouth, Massachusetts (scheduled to retire in June 2019); the Fitzpatrick, Ginna, and Nine Mile Point Unit 1 in upstate New York (all scheduled to retire in 2017, but currently subject to state action that would keep them in operation (see below)); Clinton (scheduled to retire in mid-2017) and Quad Cities (to be retired in mid-2018) in Illinois; and the Oyster Creek unit in Pennsylvania (scheduled for retirement in 2019).[37] In other parts of the U.S., other announced retirements include: the Diablo Canyon nuclear plant in California, whose 2024 retirement has already been announced)[38]; and the Fort Calhoun plant in Nebraska, which ceased operations in October 2016. [39]
- States are addressing this situation in a variety of ways: some states (like Vermont, Massachusetts, and California) have not taken action to forestall the impacts of the premature retirement of an existing nuclear unit. New York has adopted a Clean Energy Standard to provide revenues to avoid the premature retirement of financially distressed existing nuclear units listed above (i.e., Fitzpatrick, Ginna, and Nine Mile Point). And (of this writing) other states, like Illinois, are still considering other policies to maintain safely operating nuclear plants.

Meeting the full suite of Connecticut's aggressive decarbonization goals across all economic sectors will require the electric sector to play an even larger role in supplying energy than it currently does.[40] Thus, the rapidly scaling up clean-energy resources will require allowing *growth* in power generation even as the system relies on increased investments in energy efficiency. Such growth may come from fuel switching (to electricity) in the state's building stock and/or from the introduction of electric vehicles and other means to help decarbonize the transportation sector and to lessen its dependence on fossil fuels. (For example, the CT DEEP anticipates the potential need for Connecticut households, businesses, and others to adopt an estimated 0.5-1.5 million light-duty EVs by 2030.[41])

Role and importance of existing nuclear generation in transitioning to a cleaner, affordable electric system

To enable the future decarbonization of the transportation and other sectors, electricity prices will need to be cost-competitive with other fuels. From a highly pragmatic point of view, maintaining zero-carbon generating resources – while also adding new clean energy resources and investing in energy efficiency – appears to be an important strategy to assist in what is likely to be a challenging transition. This is particularly the case because the full economic, financial, social, and technical pathways to deep decarbonization are still evolving and not fully transparent at present.

New England is a case in point: nuclear generation provides approximately 30 percent of total electric supply, and 73 percent of all zero-carbon electricity (taking into account conventional hydro, wind, and solar generation in New England in 2015).[42] Millstone alone produced 40 percent of all of New England's zero-carbon electricity, and 98 percent of Connecticut's zero-carbon power supply in 2015.[43] And in New England (as in other many organized wholesale markets around the U.S.[44]) nuclear generation faces financial pressures in the wholesale energy and capacity markets.

Illustratively, when Vermont Yankee retired at the end of 2014, New England lost approximately 5,000,000 MWh of zero-carbon electricity supply. For context, in 2015, total generation from wind and solar in the six New England states amounted to 3,982,000 MWh. Had New England wanted to avoid backtracking on carbon emissions after Vermont Yankee retired, the region would have had to install renewables amounting to 1.3 times the amount that was generated by wind and solar in 2015.[45] Considering the many years it took for New England to build up its wind and solar generation to the level produced in 2015, it would take a consequential amount of effort and investment to bring that additional quantity on board and doing so would have just kept New England even in terms of zero-carbon shares of power supply – rather than helping it to cut down on emissions from carbon-emitting generating units.

The amount of clean energy supply it would take to replace Millstone is much higher than this, because Millstone is a much larger station than was Vermont Yankee: in 2015, Millstone generated 3.4 times the amount of power than Vermont Yankee did in its last year of operations.[46]

In addition, it is important to recognize that nuclear retirements are different from other power plant retirements. Unlike many other generating technologies, nuclear plants cannot practically be 'mothballed' and retained for possible use in the future because so much of the plant's costs are unavoidable in a 'temporary' shut-down. This means that once a unit is retired, its electric-system benefits – e.g., its relatively low-cost, carbon-free and reliable power supply – go away for good.

With this in mind, keeping a plant in operation provides important insurance value to an electric system that could face higher-than-expected natural gas prices and/or slower-than-expected progress in introducing new technologies into the energy mix.

Evaluation of Millstone's Value to Connecticut and its Electricity Consumers

Given Millstone's size and its zero-carbon profile, it is clear that it plays an important role in meeting the energy, capacity and carbon needs of Connecticut and the rest of New England. In an attempt to quantify some of the value that Millstone's operation provides to electric customers in the region, we simulated the dispatch of the New England system through 2030, both with Millstone in operation and then again after taking Millstone out of the resource mix in 2017.[47]

Approach:

For each of the 'with Millstone' and 'without Millstone' runs, we conducted a detailed hourly production-cost simulation, and allowed the model to economically dispatch the full set of power resources – including additional renewables in the future to meet expected customer demand at the lowest cost. The difference in total power system cost of operations and in total CO_2 and NO_x emissions between the results of the two simulations over the 2017-2030 modeling period is the basis for our primary metrics of 'value' to Connecticut, New England, and their electricity consumers.

In recognition of the important role that natural gas-fired generation plays within the region, we also relied on an integrated electric sector-natural gas sector modeling approach.[48] This allowed us to capture the impact of increased demand for gas-fired generation on natural gas prices. In this manner, we estimated both gas and electric prices in a two-step iterative manner. First, we estimated the expected increase in gas-fired generation necessary to meet system demand without Millstone. Second, we estimated the expected change in gas prices that would result from this increased demand. With these inputs in hand, we estimated total electric sector impacts, using both the forecasted gas prices and change in generation.[49]

Assumptions:

Base Case (with Millstone)

We designed our base case to reflect the existing set of electric resources, as well as known and planned changes to the electric generation sector in New England and neighboring regions that interact with the New England system. We also wanted our base case to reflect state and regional renewable-energy and climate policies, including some of the new infrastructure projects that are planned to serve electric demand in New England. Because these projects are included in both the "base" and "change" modeling runs, we do not include incremental costs to electric consumers associated with adding renewables and other clean energy projects where they are driven by State policy.

Specifically, we assumed the following:

- *Electric Demand*: That New England's demand would decline over the modeling period, based on ISO-NE's most-recent forecast which reflects planned energy efficiency measures and growth in behind-the-meter generation for solar and other distributed energy resources.[50]

- ***Renewable Portfolio Standards***: That New England, New York, and PJM states would all meet their RPS goals by adding renewable generation through 2030. We assumed that each region would meet its RPS targets through a combination of onshore wind and solar, consistent with the proportion of planned projects in each region's interconnection queue. Within New England, for example, we added an additional 5,800 MW of wind capacity and 880 MW of solar capacity.[51]
- ***Carbon goals***: That all states in the electrical Eastern Interconnect (i.e., parts of the country east of the Rockies, except for Texas) would comply with the upcoming Clean Power Plan via a mass-based approach for existing fossil generating units, and that states would authorize trading of CO_2 allowances. We further assumed that the RGGI region, which includes all six New England states, would rely upon its existing carbon trading program to meet the Clean Power Plan, with the RGGI cap extended through 2030 and declining 2.5 percent per year.[52] Consistent with current design, we assumed that all new units would be covered by the RGGI cap.
- ***Clean Energy Imports***: That the Northern Pass transmission line would be built and become operational in June 2020, and deliver 1,090 MW of firm Canadian hydroelectric power to the New England region each year thereafter, with an annual capacity factor of approximately 90 percent.[53]
- ***Resource additions and retirements***: That all new resources that have cleared in recent ISO-NE forward capacity auctions ("FCAs") would become part of the region's mix. This includes approximately 2,300 MW of new gas-fired generating capacity. Most of this is located in Connecticut: a total of 1,300 MW from three projects at Bridgeport Harbor, Wallingford, and CPV Towantic.[54] We also incorporated known and retirements approved by ISO-NE through FCA 10,[55] which includes both the Brayton Point coal and oil units and the Pilgrim nuclear unit. Notably, we assumed that all remaining nuclear units in ISO-NE, PJM, and NYISO would remain in operation throughout the 2017-2030 study. The loss of any of these resources (either through retirement or a failure to achieve permit extensions) would further stress the region's ability to meet its carbon goals going forward.
- ***Natural gas and other fuel prices***: That natural gas prices for Henry Hub would reflect current NYMEX monthly forwards through December 2018. Thereafter, we grew monthly forward prices at the annual real growth rate included in the 2016 EIA Annual Energy Outlook.[56] We relied on the internal gas model to forecast basis differentials at New England and other regional pricing points.[57] We incorporated LNG resources, as well as pipeline capacity expansion for known and approved projects, which includes the Spectra Algonquin Incremental Market ("AIM") expansion and the Kinder Morgan Connecticut Expansion.[58]

This set of assumptions in our base case model resulted in an outlook that is quite similar to current and expected changes in the New England electric generation mix. Figure 1 shows modeled generation relative to current generation, while Figure 2 shows the modeled transition toward decarbonization of the electric sector through 2030. Under the base case, in-region renewables and hydro resources are expected to account for 34 percent of total in-region generation by 2030. In this outlook, total carbon intensity of the New England power system[59] would fall (i.e., improve) from 550 lbs./MWh to 447 lbs./MWh, as the region adds additional renewables, and accounting for large scale hydro resources and Millstone generation.

Figure 1:
Comparison of Actual and Modeled System Conditions

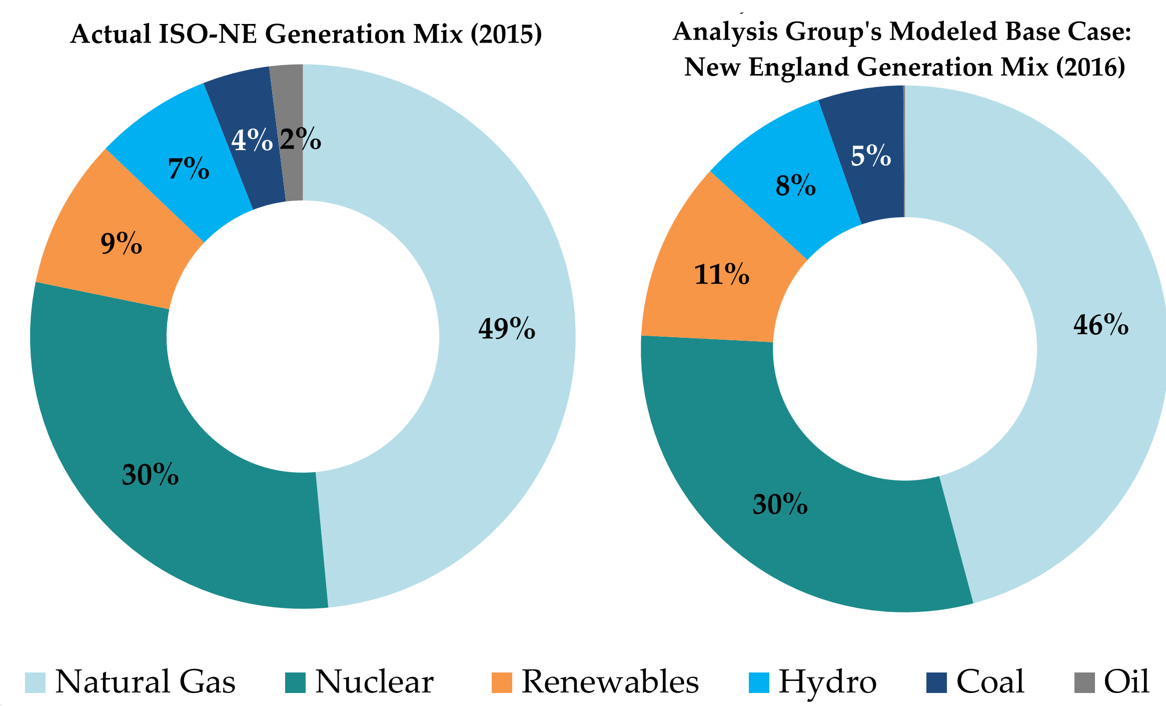
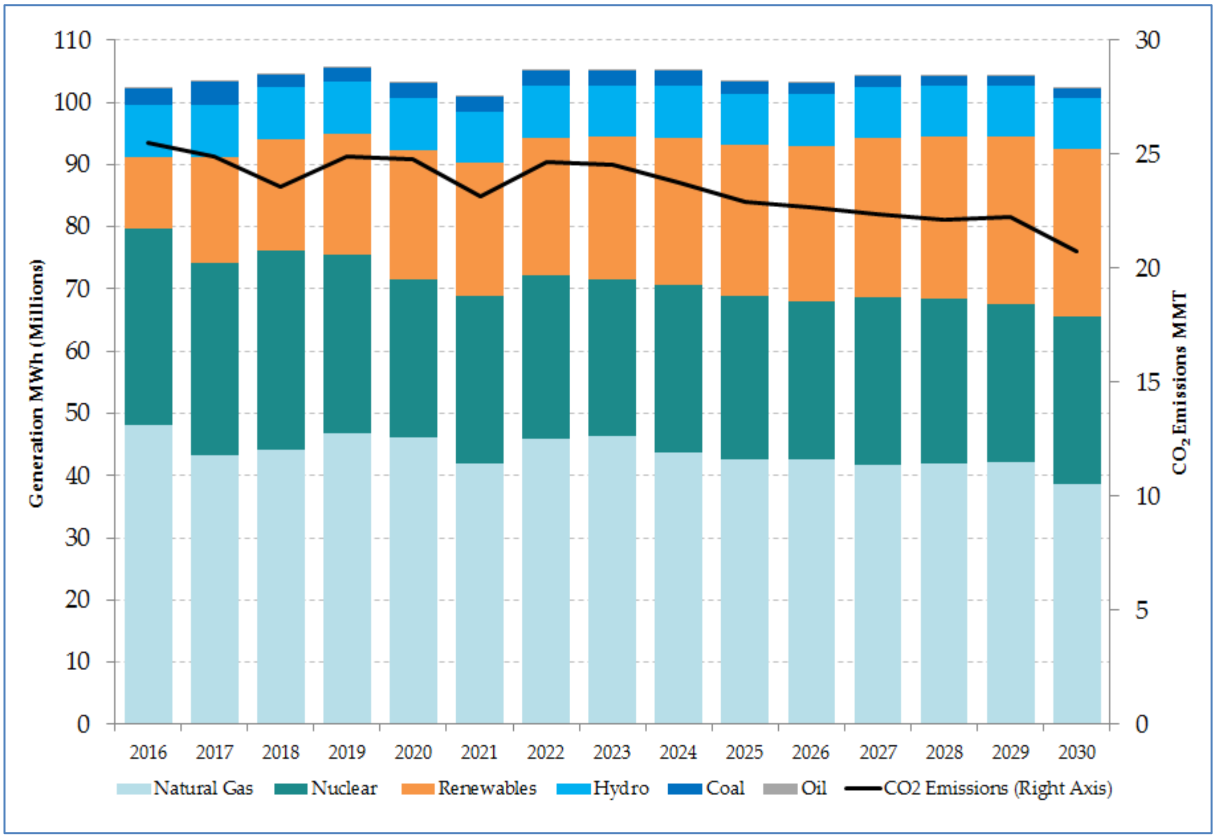


Figure 2:
Analysis Group's Estimated Base Case:
New England Generation and Emissions (With Millstone, 2016-2030)



Change case ("Without Millstone"):

Solely for the purposes of this modeling exercise, we assumed that Millstone would retire and exit the New England power system in the spring of 2017, during its upcoming and scheduled refueling cycle. We recognize that this is an entirely hypothetical retirement timeframe. We understand that ISO-NE would require significant reliability studies to be performed before retirement approval on any schedule. Our change case thus reflects a "what if…" conceptual exercise to examine price implications if such a retirement were able to occur in that time frame.

Further, we assumed that some but not all of Millstone's capacity would need to be replaced immediately in the model's change case. Using expected capacity additions in future years along with standard load and installed reserve requirements, we determined that 800 MW of capacity would need to be added in conjunction with Millstone's hypothetical retirement. We assumed that the region would add a hypothetical 800 MW natural gas combined cycle ("NGCC") unit,[60] in light of our base case having already incorporated compliance with RPS and energy efficiency targets. We understand that in reality, it would not be possible to develop, permit, and construct a new NGCC unit in that time frame. We also understand that actual capacity resources would be identified in future ISO-NE Forward Capacity Auctions ("FCA"), which are operated by the ISO-NE to procure capacity on a three-year forward basis (i.e., the FCA #11 will be held in February 2017 for the capacity commitment period 2020-2021). Again, our analysis examines "what if…" Millstone were retired and replaced with a NGCC in 2017 for the purpose of constructing alternative scenarios "without Millstone" to quantify change in system conditions.

Modeling Results

Observations for interpreting these results

The results we present here reflect a fundamental outlook – i.e., that the states and the power market in New England and elsewhere are fully meeting their clean energy goals. We believe that this conservatively estimates the value of maintaining Millstone as an operating facility between 2017 and 2030. We characterize this outlook as conservative because if -- for any reason -- some or all our base case assumptions do not hold, then the loss of the Millstone station would make it much harder and more costly for Connecticut and New England to meet their fundamental energy and environmental goals. In such a case, the adverse impacts of a Millstone retirement on consumer costs, carbon goals, and other outcomes are likely to be higher than those estimated here.

In particular, we have made a number of conservative assumptions about natural gas prices, renewables, and Canadian hydroelectric imports, which together have the effect of lowering the value of Millstone relative to what it would be if those assumptions were not in place. Higher gas prices than assumed and delays in introducing other zero-carbon supplies, whether from solar, wind, or imported hydro, would both raise the value of keeping Millstone as part of the mix. In our view, it is more likely that gas prices will increase (rather than decrease) relative to our assumed gas prices, that renewables could come online more slowly than expected (rather than faster than expected)[61] – especially in the near term – and that Canadian hydroelectric imports will arrive more slowly than we assumed (rather than earlier than expected).[62] This analysis relies on relatively optimistic assumptions about these variables, which causes us to characterize our results as a conservative estimate of the value to consumers of keeping Millstone in operation.

Similarly, even though our analysis extends to the year 2030, we assume that the electric power sector maintains the basic shape that exists *today* (based on forecasts of demand and resource additions that are part of New England's long-term planning process*).* Our analysis does not model anticipated or planned increases in demand from the potential electrification of the transportation or building end-use sectors. Connecticut's DEEP is developing analyses and plans for how the state could meet its own long-term carbon goals, and anticipates a reduction in CO_2 from the transportation sector of approximately 8 MMT. According to recent CT DEEP analyses, this reduction would result in part from the electrification of more than 462,149 vehicles by 2030 under a low scenario and more than 1,532,388 vehicles under a high scenario, with a resulting penetration of EVs in the vehicle fleet in the range of 20 percent (low-scenario) to 67 percent (high-scenario) by 2030.[63] If this mass electrification of the transportation sector were to happen, demand for electricity would certainly increase, and additional low-carbon supplies would need to be added to Connecticut's electric system. We believe that meeting such EV targets would require an equal focus on costs and carbon emissions: in other words, doing so would depend upon electricity and vehicle costs remaining cost competitive with existing liquid fuels and the vehicles that use them.

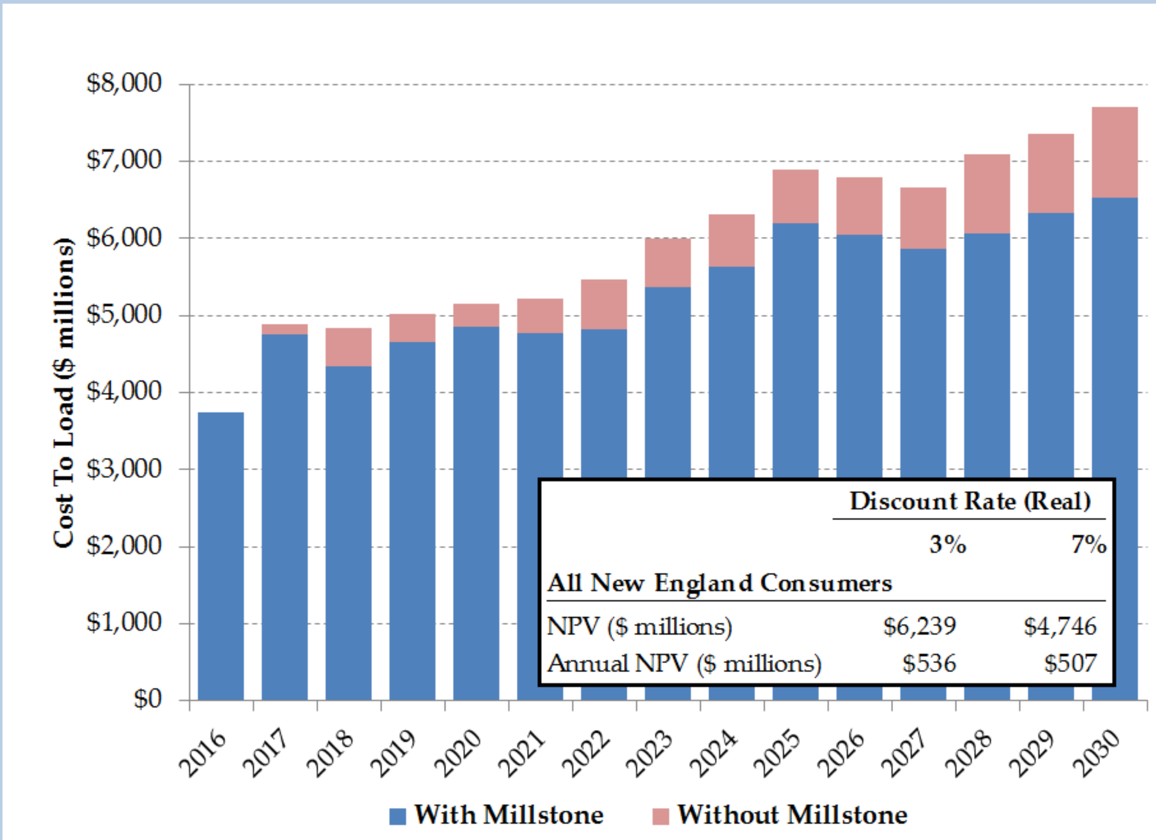
It is reasonable to anticipate that retaining relatively low-cost, zero-carbon electric generating resources could help solve that equation. Were Connecticut to see changes in its economy that increased electric load, above what we have assumed in our analysis, then this would tend to increase the value and benefits of Millstone to New England consumers. Future demand could be met through additional renewables, and some studies have suggested that electric vehicles could serve as mobile storage during periods of on-peak generation.[64] Even so, Millstone could provide additional benefits to meeting off-peak demand or prove to be a cost-effective resource for both capacity and energy, relative to increases in renewables greater than the additional 6,700 MW of wind and solar already assumed to be added to the system in this study.

Electric Consumer Impacts

Figure 3 shows the change in the annual cost to electricity consumers ("cost to load") for all New England energy consumers.[65] As indicated, the value of Millstone to the New England power system increases over time, as both gas prices rise and regional carbon caps become more stringent. To account for this value over time – and consistent with guidance from the Office of Management and Budget ("OMB") – we present all results using both a three percent and seven percent real discount rate.[66] Under OMB guidance, the higher seven percent rate is appropriate when evaluating regulations that affect private investments; in contrast, the three percent (or lower) rate is more appropriate when considering the costs and benefits of actions that affect consumers or issues related to intergenerational equity or health issues. Thus, we view the results of a seven percent discount rate to be a lower bound on the total impact to consumers.

By 2030, and assuming a three percent real discount rate, the total value of Millstone to consumers in all of New England is approximately $1 billion annually. On an annual average leveled basis, this is equal to $536 million per year. And the cumulative net present value of Millstone to New England consumers would be $6.2 billion, if all of the benefits of Millstone were enjoyed in a lump sum today.[67]

Figure 3:
Estimated New England Cost to Load With Millstone Versus Without Millstone ($ millions, 2016-2030)

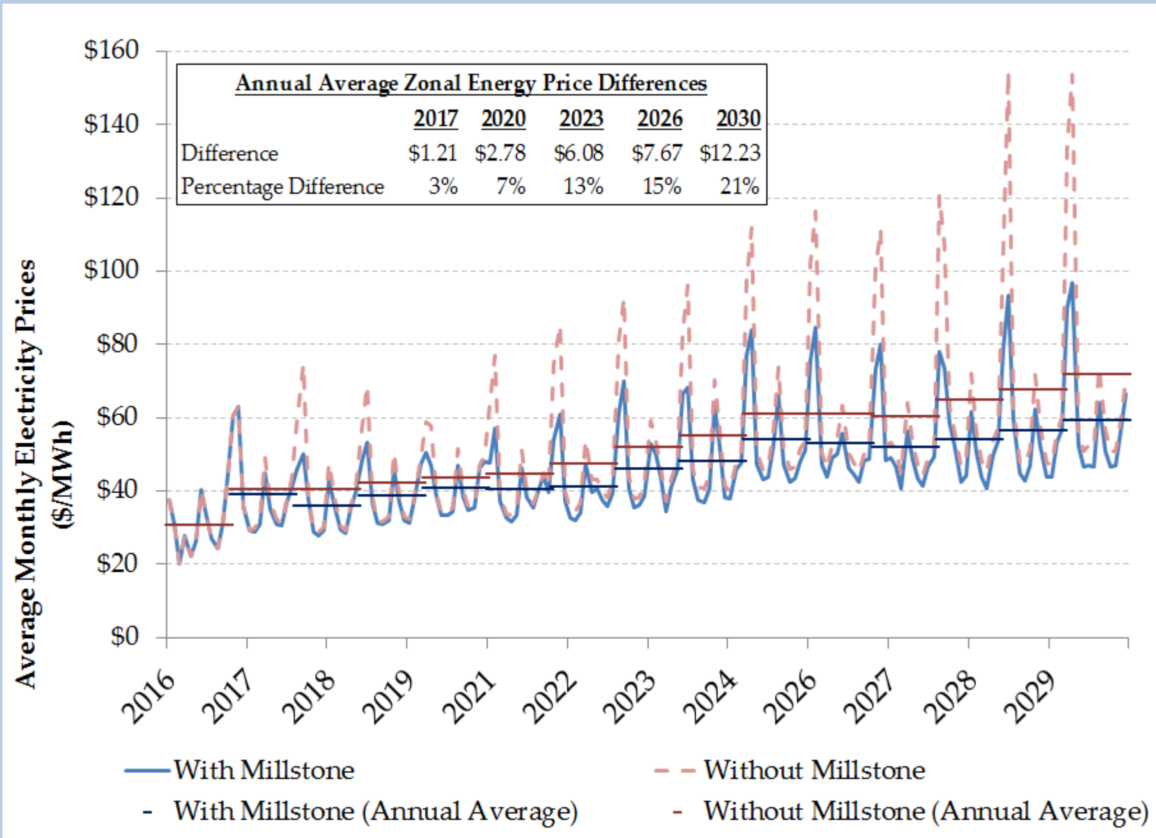


	Discount Rate (Real)	
	3%	7%
All New England Consumers		
NPV ($ millions)	$6,239	$4,746
Annual NPV ($ millions)	$536	$507

Figure 4 illustrates the change in Connecticut's average monthly electric energy prices over the modeling period. This reflects our estimate of ISO-NE electric energy-market prices that would be paid by electricity consumers in Connecticut. Again, the benefits of Millstone increase over time, and by 2030, annual average energy prices would be 21 percent higher if Millstone were retired, compared to keeping Millstone in operation.

Avoiding a Millstone retirement would save the average residential consumer more than $500 in total electric energy costs through 2030. Based on 2015 average residential bills, Connecticut residential consumers would benefit by approximately 2.5 percent on average, each year over this period.[68]

Figure 4:
Estimated Average Electricity Price in Connecticut*
With Millstone Versus Without Millstone ($/MWh, 2016-2030)



* Energy prices are for the modeled Connecticut Southwest-Norwalk zone.

These cost savings from retaining Millstone in the power system reflect its value in the ISO-NE *energy market*, only. There are likely to be capacity-cost savings as well, but these are difficult to estimate at present, for a few reasons. Were Millstone to retire in the near term, replacement capacity would need to be identified in future ISO-NE FCAs, and the prices in those capacity auctions would reflect capacity and supply conditions, the cost of new entry as well as the design of ISO-NE's capacity market. ISO-NE has recently approved a new pricing design for FCAs (based on a "marginal reliability impact", or MRI, demand curve). Given these changes and the wide range of possible replacements, it is difficult to fully estimate the incremental capacity costs from a potential loss of Millstone. At the upper bound, for example, and based on the results from FCA 10, the loss of Millstone capacity could have potentially increased total capacity costs by up to $1.5 billion for the 2019-2020 delivery year.[69] This assumes that the market would have cleared at the estimated cost of new entry for a new combined cycle unit (of $10.81/kW—month). In practice, capacity market impacts would have been lower if additional resources (above and beyond the new entry that did clear the market) would or could have offered into the market at a lower price.

Carbon and other Emission Impacts

Replacement power for a premature retirement of Millstone would be generated – at least in the near term – by existing and planned fossil-fuel power plants (because in the normal dispatch of New England's power system, renewable resources would be generating power whenever they are available to do so).

Figure 5 shows total New England power sector carbon emissions (solid black line) and Connecticut's share of those emissions with and without Millstone (blue bars). With Millstone in operation, Connecticut power generators would account for 27 percent of total in-region generation emissions in 2030; without Millstone, total Connecticut electric sector emissions would account for 33 percent of total in-region generation. This represents CO_2 emissions increasing by an average level of 2.2 MMT per year, emissions that are equivalent to adding approximately 470,000 passenger cars.

Connecticut's statutory, long-term goal is to reduce total annual state-wide and economy-wide GHG emissions by an additional 20 MMT by 2050 beyond currently installed programs, with 3.2 MMT of those reductions expected to come from the electric power sector. Because the CT DEEP's long-term analyses assume that Millstone continues to operate through its current licenses – July 31, 2035 for Millstone Unit #2 and November 11, 2045 for Millstone Unit #3[70] – losing Millstone would make the state's tasks more daunting. Total in-state emissions would increase by an average of 2.2 MMT per year (see Figure 6). This represents almost 10 percent of the entire statewide goal and nearly 70 percent of the total electric sector goal.

Similarly, emissions of other criteria pollutants would be expected to increase if Millstone were to retire. We found that the higher amount of natural gas-fired generation would lead to an increase in annual NO_x emissions of 2,423 metric tons by 2030, a 38 percent increase.

Figure 5:
Estimated New England and Connecticut CO_2 Emissions, With Millstone Versus Without Millstone (2016-2030)
(CT Share of NE's Total CO_2 Emissions and Tons of CO_2 Emissions)

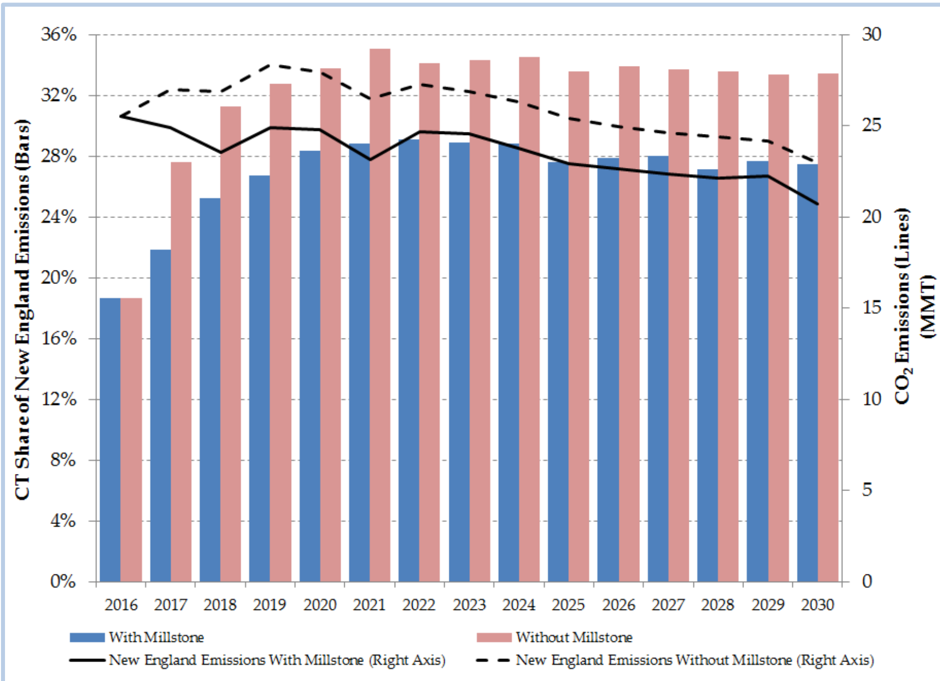
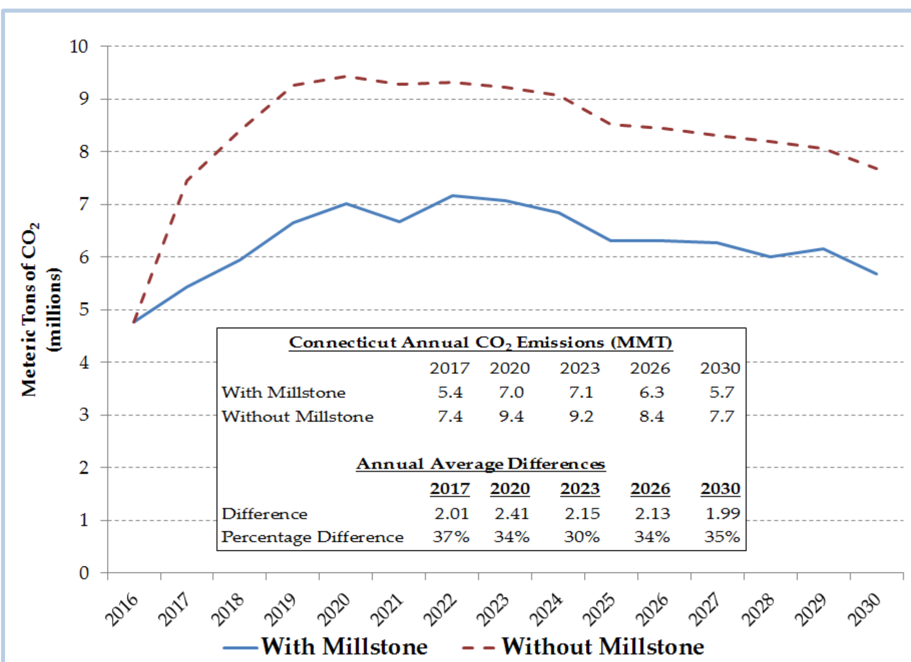


Figure 6
Estimated Connecticut CO_2 Emissions, With Millstone Versus Without Millstone (MMT, 2016-2030)



Connecticut Annual CO_2 Emissions (MMT)

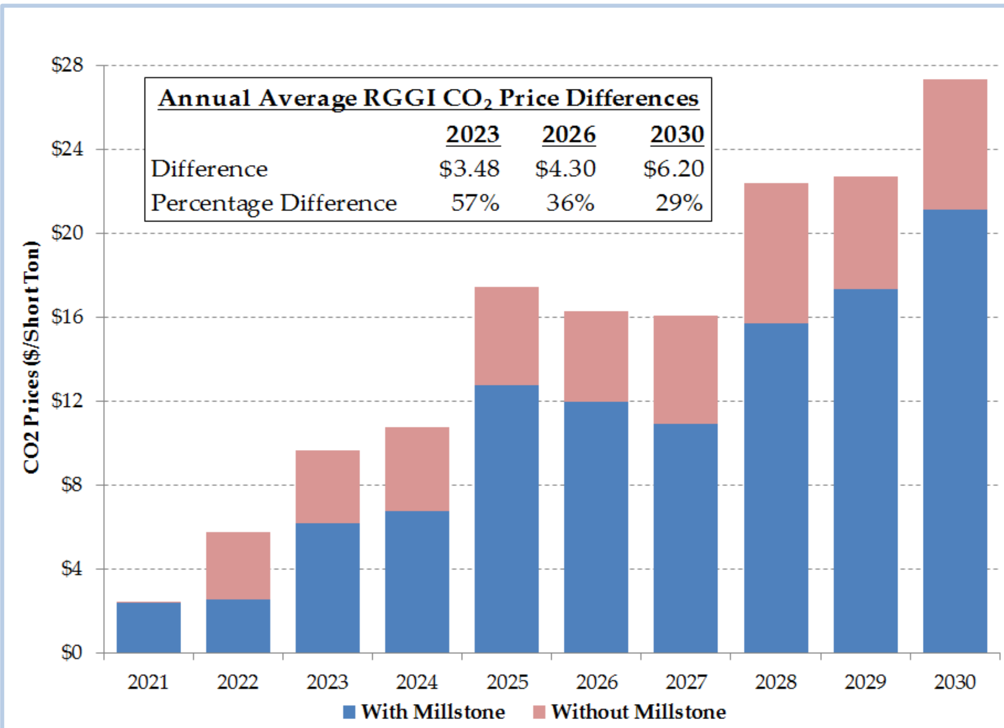
	2017	2020	2023	2026	2030
With Millstone	5.4	7.0	7.1	6.3	5.7
Without Millstone	7.4	9.4	9.2	8.4	7.7

Annual Average Differences

	2017	2020	2023	2026	2030
Difference	2.01	2.41	2.15	2.13	1.99
Percentage Difference	37%	34%	30%	34%	35%

At the same time, increased natural gas fired generation and increased CO_2 emissions would put pressure on prices of CO_2 allowances in the RGGI region. Region-wide, the cap would prevent an overall increase in carbon emissions, but local CO_2 emissions would rise, as would the price of CO_2 allowances. Our analysis indicates, for example, that CO_2 prices would be nearly 30 percent higher by 2030 in the without-Millstone case (Figure 7).[71] These contribute to the higher electricity prices we observed in the without-Millstone case, compared to keeping Millstone in operations through 2030.

Figure 7:
Estimated RGGI CO_2 Emission Prices,
With Millstone Versus Without Millstone ($/Short Ton, 2021-2030)



Natural Gas Impacts and Electric-System Reliability Concerns

The additional CO_2 emissions described above will largely come from increased use of natural gas to produce power in the region as a result of a Millstone retirement. Starting on day one after Millstone retires, its output is replaced by generation at new and existing gas-fired power plants. As shown in Figure 2 above, overall gas-fired generation is expected to decline over time in any event, as the region adds increasing quantities of renewable resources and total annual energy demand declines with increasing energy efficiency measures. But even in the base case (with Millstone operating through our full study period), gas-fired generation continues to provide 38 percent of total regional generation (see Figure 8.) This generation, and the resulting demand for natural gas, is expected to create continued winter basis differentials in the price of natural gas serving power plants in New England (see Figure 9).

Our analysis indicates that without Millstone, New England's power system would become even more reliant on natural gas generation, which would provide 51 percent of total power supply. And at the same time, total gas fired generation would remain constant. That is, the total MWh of gas-fired generation in 2030 (48 million MWh) would be equal to the total MWh of gas-fired generation in 2016 (as modeled, 48 million MWh).

The demand for natural gas to meet this power-sector demand would be expected to increase delivered natural gas prices in New England, on both an annual average and winter basis. Gas-fired generators would continue to be the marginal unit in New England,[72] and these higher gas prices would in turn be passed on to electricity consumers in the form of higher electricity prices as described above.[73] We have not captured the potential increases in total energy costs to the region associated with such spillover effects.

Our study has not explicitly examined the question of whether Millstone could retire in the near term without introducing electric-system reliability concerns in Connecticut or elsewhere in New England. Any actual retirement of the capacity at the Millstone Station – the largest power station in New England – would have to be preceded by load-flow and other technically complex reliability studies. We do acknowledge, however, the many indications suggesting that loss of such a large, baseload, non-gas-fired generating station would increase the reliability challenges facing New England, as it deepens its dependency on natural gas for power generation.[74]

Figure 8:
Natural Gas Fired Generation, With Millstone Versus Without Millstone
Percentage of Total New England Generation (2016-2030)

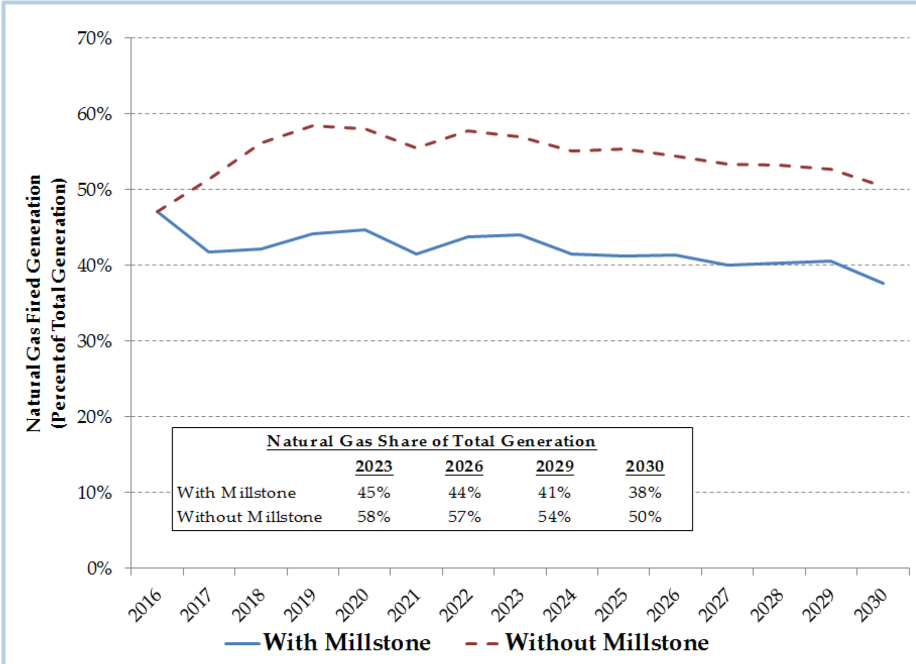
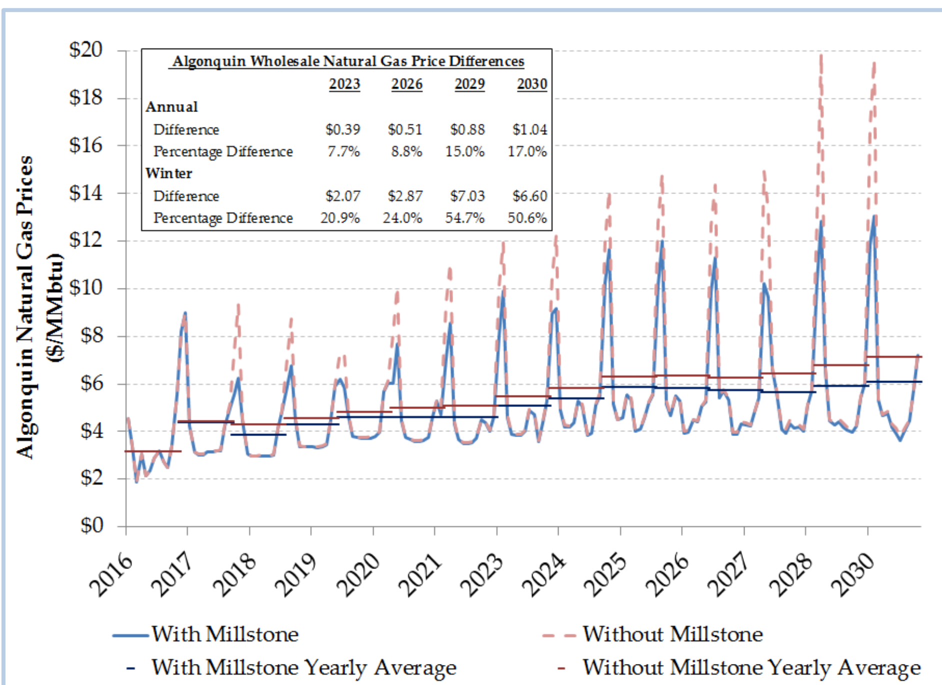


Figure 9:
New England Wholesale Natural Gas Prices,
With Millstone Versus Without Millstone ($/MMBtu, 2016-2030)



Conclusions: Insights about the value of Millstone

Our analysis indicates that maintaining Millstone's operations provides positive value to Connecticut, in terms of avoiding increases in consumers' bills, in local carbon emissions, and in the prices of natural gas that serves energy markets in the state. These benefits are important and substantial.

Even assuming that Connecticut and other New England states stay on track in meeting their goals of adding renewables and Canadian hydropower to the region's energy mix in a timely way, Millstone is important for supporting Connecticut's energy transitions in an affordable and reliable way. Keeping Millstone as an operating facility helps to support movement in that direction, from a carbon-reduction and cost-containment point of view.

In the event that natural gas prices end up being higher than expected, Millstone is important for providing reliable power and mitigating electricity price increases. As a baseload generating resource providing half of Connecticut's electricity requirements and using a technology that does not rely on natural gas, Millstone's value is clearly positive. And in the event that there is slower-than-expected progress in deploying renewables or in procuring/delivering baseload hydro supplies from Canada, then Millstone will be particularly valuable – from a carbon-control, electricity price point of view.

ENDNOTES

[1] Dr. Tierney is a Senior Advisor at Analysis Group, and formerly Assistant Secretary for Policy at the U.S. Department of Energy, Massachusetts' Secretary of Environmental Affairs and a commissioner at the Massachusetts Department of Public Utilities. As a consultant, she has previously testified before utility regulatory agencies in many states, the Federal Energy Regulatory Commission, the U.S. Congress, state legislatures, and as an expert witness in proceedings before federal and state courts. She chairs the Electricity Advisory Council of the U.S. Department of Energy, previously served on the Secretary of Energy's Advisory Board, and serves on the boards of various non-governmental organizations.

Mr. Aubuchon is a Manager at Analysis Group. He has consulted to individual utilities, system and region planners, and private developers within the electricity, natural gas, and water markets on a wide range of cases, including individualized project finance and asset valuations, planning evaluations and production cost-modeling of system reliability and regional environmental emissions, and consumer-impact analyses for consideration in regulatory proceedings. Prior to joining Analysis Group, Mr. Aubuchon worked at the Federal Reserve Bank of St. Louis, where he specialized in monetary policy and financial markets.

For the current study, Dr. Tierney and Mr. Aubuchon relied upon Dominion's modeling team to run the Aurora electric sector production cost model and the GPCM natural gas market model under their supervision. These two models are commonly used by system planners and other market participants, and were used in the current study to model the New England region with and without Millstone. Dr. Tierney and Mr. Aubuchon analyzed and interpreted the modeled results.

[2] Connecticut Department of Energy and Environmental Protection ("CT DEEP"), "2013 Comprehensive Energy Strategy for Connecticut," February 19, 2013, page iii. http://www.ct.gov/deep/lib/deep/energy/cep/2013_ces_final.pdf.

[3] "From 1990 to 2012 Connecticut reduced its emissions by 10.5%, thereby reaching its 10% reduction by 2020 target under the Global Warming Solutions Act and now aims to continue this progress and achieve greater reductions" CT DEEP, "Clean Energy Strategy Scoping Presentation," May 24, 2016. http://www.ct.gov/deep/lib/deep/energy/ces/CES_Public_Scoping_Presentation_May_24_2016.pdf.

[4] Energy Information Administration ("EIA"), State-level generation and fuel data (EIA-923 survey data), https://www.eia.gov/electricity/data.cfm#generation. EIA, "Electric Power Monthly," February 2016, with Tables 1.9.B (nuclear), 1.10.B (conventional hydro), 1.14.B (wind), and 1.17.B (solar – distributed and utility scale). http://www.eia.gov/electricity/monthly/.

[5] We present our economic-impact results using a 3-percent real discount rate, consistent with guidance from the Federal Office of Management and Budget, and assuming a 2-percent inflation rate to convert nominal and real dollars (which is an inflation rate consistent with long-term forecasts from the Survey of Professional Forecasters). In stating a net present value amount of savings into an annual savings for each residential customer, we annualize all values in real terms through 2030.

[6] This is the difference in ***electric-energy market*** costs to serve electricity consumers' demand (load) in the 'with Millstone' versus 'without Millstone' modeling analysis.

[7] All forecasts of capacity costs depend on the shape of the capacity supply curve and the marginal cost for the next available generating resource. FCA #10 recently cleared approximately 35,000 MW of capacity at $7.03/kW-month. Based on the then current, linear sloped demand curve, the net loss of 1,200 MW (Millstone plus 800 MW combined cycle replacement) would have increased capacity prices to $12.41/kW-month, which is greater than the estimated net Cost of New Entry ("CONE") of $10.81/kW-month. Assuming that the market would have cleared at net CONE ($10.81/kW-month), incremental costs would have been approximately $1.5 billion. This is calculated as 35,000 MW times the difference between $10.81/kW-month and $7.03/kW-month. This represents a one-time cost associated with the annual results of that auction. Capacity auction results will also differ in later years following a retirement; the total cost impact will depend on the Installed Capacity Requirement ("ICR") in future auctions, the total quantity of new entry in that year, and the shape of the capacity supply curve in that year, including the marginal cost of the next available generating resource. For example, if the market cleared at $9.55/kW-month (the price from FCA #9), incremental costs would have been approximately $1.0 billion.

[8] See Figure 7 relating to the 'Connecticut GHG Emissions Reference Case,' developed as part of the Governor's Council on Climate Change ("GC3") Exploratory Report, July 2016. Connecticut's "reference case" includes future reductions due to Connecticut's Renewable Portfolio Standard; the Regional Greenhouse Gas Initiative 2013 carbon cap; and federal regulations for energy efficiency. Available: http://www.ct.gov/deep/cwp/view.asp?a=4423&Q=568878&deepNav_GID=2121

[9] Greenhouse Gas Equivalencies Calculator. (n.d.). Retrieved November 02, 2016, from https://www.epa.gov/energy/greenhouse-gas-equivalencies-calculator . We calculated the number to be 419,771 passenger cars.

[10] CT DEEP Presentation, "Meeting of the Governor's Council on Climate Change (GC3)," September 8, 2016.

[11] This is based on our modeling assumption that the RGGI states will seek to lower their CO_2 targets by 2.5 percent a year going forward.

[12] For example, in a presentation made by the CT DEEP as part of the Comprehensive Energy Strategy ("CES") scoping session on May 24, 2016, the following points were made about electric and gas interdependencies and concerns in New England:

> Guiding Principles for 2016 CES" [include addressing] increased reliance on natural gas generation, gas pipeline constraints. Winter Operations Highlight Natural Gas Pipelines Constraints as a Continuing Reliability Challenge:
>
> - Close to half—13,650 MW, or 44%—of the total generating capacity in New England uses natural gas as its primary fuel
> - 2015/16 winter outlook identifies up to 4,220 MW of natural gas-fired generation at risk of not being able to get fuel when needed
> - To address continuing concerns about natural gas pipeline constraints, the ISO will administer Winter Reliability Programs until 2018 to help improve fuel security and protect power system reliability.

(See CT DEEP: http://www.ct.gov/deep/lib/deep/energy/ces/CES_Public_Scoping_Presentation_May_24_2016.pdf.)

Also, the head of ISO-New England, Gordon van Welie, recently warned "that natural gas pipeline constraints, power plant retirements, and states' renewable and environmental policies threaten to make the region's power system unsustainable during extreme winter conditions after 2019, SNL reported yesterday. 'We currently have a precarious operating situation in the winter time and we're worried about it becoming unsustainable beyond 2019,' van Welie told SNL in an interview. 'The reality is that we're really operating with a very slim operating margin during the winter time that may not cover these large contingencies that worry us. To date, the combination of coal, nuclear, oil and liquefied natural gas-fired generation have kept New England's lights on during the coldest winter snaps, such as the 2014 polar vortex, when demand for gas to heat buildings limited fuel supplies for natural gas-fired generators. Van Welie fears what could happen if the increasingly gas-dependent Northeast were to lose any more of its baseload generation that's not fired by gas. A Sept. 28 presentation by van Welie outlined those concerns and warned the region's problem of meeting electricity demand as a result of inadequate natural gas infrastructure all year round, but especially during winter. Beyond the uncertain future of some 997 MW of capacity from four coal and oil-fired plants in New Hampshire, once they are divested by Eversource Energy subsidiary Public Service Co. of New Hampshire, van Welie is troubled by the planned retirements in Massachusetts of Dynegy's roughly 1,500-MW Brayton Point coal and oil-fueled plant by June 2017 and Entergy Corp.'s nearly 684-MW Pilgrim nuclear plant by June 2019. Van Welie is also concerned that permits to run plants that burn gas and another fuel are now increasingly difficult to obtain and that the run times of those are being restricted as states tighten their air emissions regulations.." "ISO New England's van Welie has serious concerns about winter reliability post -'19," ElectricityPolicy.com, October 11, 2016. https://www.electricitypolicy.com/News/iso-new-england-worries-about-reliability-post-2019.

[13] New England generators are served by natural gas at three primary locations: Algonquin, Iroqouis Zone 2, and Tennessee Zone 6. The Algonquin City Gate index is typically assumed to be the most representative of gas costs in New England. See, for example, Potomac Economics, 2015 Assessment of the ISO New England Electricity Markets, June 2016, at 17 and 43.

[14] The most recent Connecticut Comprehensive Energy Strategy ("CES") (2013) includes the following findings and goals: "Providing Connecticut's citizens with cheaper, cleaner, and more reliable electricity is a core focus of the Strategy." http://www.ct.gov/deep/lib/deep/energy/cep/2013_ces_final.pdf. The CES is currently under review by the CT DEEP, and is being guided by the following principles: "Cheaper, Cleaner, More Reliable and Sustainable… for Communities and Customers. Cheaper: Lower bills; Reduced volatility; Equitable rates; Equal opportunity for energy savings; Lower fuel costs, relative to other types of fuels; Scaling clean energy resources at lowest cost to ratepayers through optimal use of grants and financing; Connecticut's 2015 Economic Development Strategy." The Connecticut Global Warming Solutions Act of 2008 requires that the state: "Reduce greenhouse gas emissions by 10% below 1990 levels by 2020 → Reduce greenhouse gas emissions by 80% from 2001 levels by 2050." CT Clean Energy Strategy Scoping Presentation, http://www.ct.gov/deep/lib/deep/energy/ces/CES_Public_Scoping_Presentation_May_24_2016.pdf.

[15] In his cover letter for the current CES in 2013, Governor Malloy highlighted the "need to deploy a portfolio of energy options for consumers and expand energy efficiency as the surest way to lower energy bills, reduce the budget stress from

electricity costs, and improve our state's competitiveness." http://www.ct.gov/deep/lib/deep/energy/cep/2013_ces_final.pdf.

[16] EIA, State-level generation and fuel data (EIA-923 survey data), https://www.eia.gov/electricity/data.cfm#generation.

[17] EIA, "Energy-Related Carbon Dioxide Emissions at the State Level, 2000-2013," October 2015. http://www.eia.gov/environment/emissions/state/analysis/pdf/stateanalysis.pdf (hereafter referred to as "EIA State Carbon Emissions Report"), Figure 2. The data reported here are for 2013, the latest year for which such state-by-state comparisons have been published by EIA.

[18] EIA State Carbon Emissions Report, Table 6. In Connecticut, the economy uses 3,400 Btu per dollar of Gross State Product, as does Rhode Island and Maryland. Massachusetts has the lowest, at 2,800; California has the second lowest, at 3,300. The state that has the worst energy productivity is Wyoming, at 24,900.

[19] EIA State Carbon Emissions Report, Table 7.

[20] In two thirds of the states in the U.S., the power sector is responsible for at least 30 percent of the state's total energy-related carbon emissions, with some states' power sector share being as high as 70 percent. EIA State Carbon Emissions Report, Table 4.

[21] EIA State Carbon Emissions Report, Table 4. EIA, State-level generation and fuel data (EIA-923 survey data), https://www.eia.gov/electricity/data.cfm#generation.

[22] In 2015, Millstone generated 17,410,917 megawatt hours ("MWh"); New England's 2015 system demand was 126,955,000 MWh. EIA, State-level generation and fuel data (EIA-923 survey data), https://www.eia.gov/electricity/data.cfm#generation; ISO-NE "Key Statistics," https://www.iso-ne.com/about/key-stats.

[23] http://www.ct.gov/deep/lib/deep/energy/rps/rps_final.pdf.

[24] Connecticut's Global Warming Solutions Act of 2008 also requires the state to reduce GHG emissions by 10 percent below 1990 levels by 2020 and by 80 percent from 2001 levels by 2050. https://www.cga.ct.gov/2008/ACT/PA/2008PA-00098-R00HB-05600-PA.htm . See also Connecticut's Clean Energy Strategy Scoping Presentation, http://www.ct.gov/deep/lib/deep/energy/ces/CES_Public_Scoping_Presentation_May_24_2016.pdf .

[25] http://www.ct.gov/deep/cwp/view.asp?a=4405&Q=570416&deepNav_GID=2121.

[26] Public Act 15-107: The Affordable and Reliable Energy Act of 2015. https://www.cga.ct.gov/2015/ACT/pa/pdf/2015PA-00107-R00SB-01078-PA.pdf.

[27] This progress is under the direction of Governor Malloy's Executive Order 46 of April 2015.

[28] 2,436 MW of new gas-fired capacity has been added to the system between 2000 and 2015. Of that amount, 135 MW of capacity is at relatively small-scale generating units at commercial and industrial locations, and 2,300 MW is utility-scale capacity owned by electric utilities and non-utility generating companies. See the EIA generator database. During half of the years since 2008, when natural gas prices were $10.07 per MMBtu, average annual gas prices in New England have been below $5.00; gas prices averaged $4.73 in 2015. Compared to total annual wholesale energy-market payments by consumers in New England in 2008 – when they amounted to $12.1 billion – the amount was $5.91 million in 2015. ISO-New England, "New England's 2015 Average Wholesale Power Price Fell to Second-Lowest Level Since 2003: Low natural gas prices drove down power prices for most of the year," March 29, 2016. https://www.iso-ne.com/static-assets/documents/2016/03/20160329_prelim_2015_prices_release.pdf.

[29] See, for example, CT DEEP, Air Quality Trends for sulfur dioxides ("SO_2"), nitrogen oxides ("NOx"), and particulate matter ("$PM_{2.5}$"). http://www.ct.gov/deep/cwp/view.asp?a=2684&q=322066&deepNav_GID=1744.

[30] EIA 860 generator database. https://www.eia.gov/electricity/data/eia860m/xls/june_generator2016.xlsx .

[31] Bloomberg New Energy Finance ("BNEF"), Sustainable Energy in America Factbook, 2016, pages 8, 56-67. https://about.bnef.com/white-papers/sustainable-energy-in-america-2016-factbook/.

[32] See, for example: companies that have signed on to Corporate Renewable Energy Buyers' Principles. http://www.wri.org/publication/corporate-renewable-energy-buyers-principles); and colleges and universities that are tracking and reporting their own carbon footprints (including many higher-educational institutions in Connecticut: http://reporting.secondnature.org/search/?institution_name=&commitment_type=%3F%3F&carnegie_class=%3F%3F&state_or_province=CT).

[33] J.H. Williams, B. Haley, and R. Jones. "Policy Implications of Deep Decarbonization in the United States," published by Energy and Environmental Economics, Inc. (E3) and the Deep Decarbonization Pathways Project, 2015. See http://usddpp.org/

[34] EIA, "Vermont Yankee nuclear plant closure in 2014 will challenge New England energy markets," Today in Energy, September 2013, http://www.eia.gov/todayinenergy/detail.php?id=12851; Entergy press release, "Entergy to Close, Decommission Vermont Yankee," August 27, 2013, http://www.entergy.com/News_Room/newsrelease.aspx?NR_ID=2769.

[35] EIA, "Lower prices and high repair costs drive nuclear retirements," Today in Energy, July 2013, http://www.eia.gov/todayinenergy/detail.php?id=11931.

[36] BNEF, "Reactors in the red: financial health of the US nuclear fleet," July 7, 2016.

[37] BNEF, "Reactors in the red: financial health of the US nuclear fleet," July 7, 2016, page 3.

[38] BNEF, "Reactors in the red: financial health of the US nuclear fleet," July 7, 2016, page 3.

[39] See: http://www.omaha.com/money/today-fort-calhoun-nuclear-plant-will-go-offline-for-good/article_0ff3a902-5cd6-52d8-a720-b2b9bc6ec0de.html

[40] For example, the CT DEEP's presentation to the GC3 on June 16, 2016, pointed out that addressing climate change would require several critical transitions, including energy efficiency and "Fuel switching in transportation/buildings (e.g., electrify)." http://www.ct.gov/deep/lib/deep/climatechange/gc3/gc3_meeting_6_16_2016.pdf

[41] Meeting of the GC3, September 8, 2016. The Connecticut "wedges" analysis assumes different trajectories for the pace of deployment of light-duty EVs, plus additional electrification of the heavy-duty vehicle fleet. Notably, the "Wedges" analysis assumes that the Millstone units remain in operation through their full license periods.

[42] EIA, "Electric Power Monthly," February 2016 (showing full year of data for 2015), Tables 1.9.B (for nuclear), 1.10.B (for conventional hydro), 1.14.B (for wind), and 1.17.B (for solar PV, including both utility-scale and distributed solar). In New England as a whole, there were 43,510,000 MWh of nuclear, conventional hydro, wind, and solar, with the following shares of each: nuclear (73%); conventional hydro (18%), wind (5%), and solar (4%). http://www.eia.gov/electricity/monthly/

[43] EIA, "Electric Power Monthly," February 2016, Tables 1.9.B (for nuclear), 1.10.B (for conventional hydro), 1.14.B (for wind), and 1.17.B (for solar PV, including both utility-scale and distributed solar).

[44] Whitney Herndon and John Larsen, "Nukes in the Crosshairs Revisited: The Market and Emissions Impacts of Retirements," Rhodium Group, November 4, 2016, http://rhg.com/notes/nukes-in-the-crosshairs-revisited. This new analysis indicates that:

> **Nuclear under pressure:** Five nuclear power plants have retired over the past five years and a number of other plants are at risk. We estimate that an additional 24 gigawatts (GW) of existing nuclear capacity nation-wide could close between now and 2030 unless additional policy action is taken, both in competitive and regulated markets.
> **Electricity market impact:** Lost generation from recently retired nuclear power plants has been replaced primarily with fossil fuels. We expect that to be the case for future retirements as well. The exact impact depends on the fate of the Clean Power Plan (CPP) in court and the design of state implementation plans (SIPS) if the CPP is upheld. Regardless of regulatory scenario, we estimate that over 75% of the lost generation from at-risk nukes would be replaced by fossil generation, largely from natural gas combined cycle (NGCC) power plants.

[45] EIA, "Electric Power Monthly," February 2016 (showing full year of data for 2015), Tables 1.9.B (for nuclear), 1.10.B (for conventional hydro), 1.14.B (for wind), and 1.17.B (for solar PV, including both utility-scale and distributed solar). http://www.eia.gov/electricity/monthly/

[46] EIA, "Electric Power Monthly," February 2016. Table 1.9.B (for nuclear). In 2015, Millstone generated 17,411,000 MWh; in 2014, Vermont Yankee generated 5,061,000 MWh.

[47] Specifically, we relied on the Aurora production cost model. Aurora is commonly used by system planners and other market participants to forecast market changes. We relied on a zonal representation of the New England energy system, which allows us to estimate efficiently the average energy prices within a given zone. We used five zones, with Connecticut split into two zones: a central zone (including parts of Rhode Island and Southeast Massachusetts) and a southwest zone that includes Norwalk Harbor. Within Aurora, we imposed a CO_2-emissions limit and iteratively solve for the CO_2 shadow price that would meet the constraint. Additional information on Aurora is available here: https://www.auroraer.com/models

[48] We relied on the GPCM natural gas market model. GPCM is commonly used by system planners and other market participants to forecast natural gas prices under changes in demand and supply. The GPCM model includes a full representation of interstate pipelines and delivery points, with individual supply and demand curves by region. We relied on the GPCM default supply-and-demand curves with two notable exceptions: First, we used contract prices for LNG supplies consistent with public terms provided in the recent report of Paul J. Hibbard and Craig P. Aubuchon, "Power Sector Reliability in New England: Meeting Electric Resource Needs in the Era of Growing Dependence on Natural Gas,"

2015. Second, we included only currently known and permitted natural gas delivery infrastructure expansions. Within our model, this is limited to the Algonquin Incremental Market ("AIM") project (a 0.342 Bcf/day expansion in New York, Massachusetts, and Connecticut) and the Kinder Morgan Connecticut Expansion Project (a 0.072 Bcf/day expansion). It also includes two expansions of a cumulative 0.5115 Bcf/day on the Algonquin Maritimes & Northeast lines in November 2016 and November 2017.

[49] All modeling runs were developed under the direction of the authors from Analysis Group, who similarly provided all input assumptions and benchmarked all output results against existing ISO-NE conditions. Analysis Group was responsible for all post-processing of output, and estimation of consumer and other benefits. All modeling runs were conducted by the Dominion analytical team, using the Aurora electric sector production cost model and the GPCM natural gas market model.

[50] Our modeling relied on the annual gross energy net of passive demand response ("PDR") and photovoltaic ("PV") forecast from ISO-NE, and the peak demand forecast under the 50-50 weather conditions. Notably, over our modeling period, total annual demand is expected to *decline* by 3 million MWh, which reduces the need for future generation. See ISO-NE Capacity, Energy, Load, and Transmission ("CELT") 2016 Forecast.

[51] We estimated total renewable capacity needs using forecasted RPS demand projections from the Lawrence Berkeley National Laboratory, and default capacity factors from the Aurora model. For LBNL data, see: Ryan Wiser, Galen L. Barbose, Jenny Heeter, Trieu Mai, Lori Bird, Mark Bolinger, Alberta Carpenter, Garvin A. Heath, David Keyser, Jordan Macknick *et al*, "A Retrospective Analysis of the Benefits and Impacts of U.S. Renewable Portfolio Standards," LBNL, 2016: U.S. RPS Demand Projects XLSX Attachment.

[52] As a point of comparison, note that the RGGI 2016 Program Review has included scenarios that contemplate up to a 5-percent annual reduction in the cap. For additional information, see: ICF International, "Draft 2016 RGGI Program Review; CPP Reference Cases & Modeling Scenarios" RGGI, Inc., 2016. (See: https://www.rggi.org/design/2016-program-review/rggi-meetings) We further assumed that in any year in which the Clean Power Plan ("CPP") had higher emissions limits (caps) than our assumed RGGI cap, then such surplus allowances would be retired. Within the Aurora model, we iterated to solve for the RGGI and Clean Power Plan price that would allow the region to meet these CO_2 goals, respectively.

[53] We did not assume additional imports of Canadian hydropower on other projects, such as the Champlain Hudson Power Express. Multiple transmission lines and exports may require the development of new Canadian Hydro supplies. At this time, it is unclear whether the cost of both transmission and new capacity would remain cost-competitive with other clean energy goals, and whether States would pursue these projects at this higher cost. (See Susan Tierney, "Proposed Senate Bill No. 1965: An Act Relative to Energy Sector Compliance with the Global Warming Solutions Act Potential costs and other implications for Massachusetts consumers and the state's and region's electric system," September 2015.). If instead imports were directed to regions other than ISO-NE, then value of Millstone would be greater than what we have estimated here.

[54] The addition of these new, efficient natural-gas combined-cycle and combustion-turbine power plants helps to mitigate zonal energy price increases without Millstone; they also contribute to increases in in-state GHG emissions.

[55] ISO-NE, "Forward Capacity Auction #10 Results," 2016. Results are available here: https://www.iso-ne.com/isoexpress/web/reports/auctions/-/tree/fcm-auction-results

[56] EIA, "Annual Energy Outlook 2016: Energy Prices by Sector and Source," 2016.

[57] Specifically, we relied upon the GPCM.

[58] During winter months, LNG imports from Cannaport reach peak totals of approximately 0.5 Bcf/day in our analysis, which is within its maximum capacity of 1.3 Bcf/day. We relied on EIA's Annual Energy Outlook 2016 for a forecast of delivered coal prices, and Aurora defaults for all remaining fuel prices. Consistent with other production-cost models, Aurora relies on monthly fuel prices for fossil-fuel generators. As a result, the model does not forecast economic fuel switching between gas and oil for dual-fuel units. This will have two off-setting effects within the model: First, dual-fuel operation would be expected to decrease total gas demand during peak periods, and mitigate increases in natural gas prices. Second, emissions from dual fuel-resources would increase demand for RGGI allowances and increase CO_2 prices. These effects may be expected to offset one another, with respect to total costs to consumers.

[59] This was calculated as in-region emissions divided by total in region generation.

[60] We conservatively estimated that this is the minimum quantity required to meet a projected 15-percent system wide reserve margin in New England, based on the summer capacity ratings of all resources within the system. We further assumed that wind and solar were derated to 5 percent and 26 percent of their nameplate capacity, respectively, for resource-adequacy calculations. This is consistent with technical transmission planning documents and assumptions used by ISO-NE. Our analysis indicated that the loss of Millstone's capacity would be partially replaced by expected future

additions in 2018 and 2019, and further offset by the effect of energy efficiency and behind-the-meter generating resources on peak demand. Further, we assumed that a new, efficient natural gas combined-cycle unit entering the market soon after the retirement of Millstone would tend to mitigate the wholesale energy-market price impacts from the retirement of Millstone. Had that new natural-gas-fired unit not been assumed to enter the market soon after Millstone's retirement, then near-term post-retirement prices would likely have been higher than modeled here, because energy demand would have been met by older, less efficient existing units.

[61] For example, if the region failed to fully expand the supply of renewable resources, then the carbon free generation from Millstone would provide even greater benefits and option value under increasingly more stringent CO_2 cap. Slower growth in renewables could occur for a variety of reasons, such as potential challenges with the siting and permitting of the more than 6,000 MW of wind and solar included in this study, or of siting transmission facilities needed to deliver their energy.

[62] If baseload Canadian hydro resources end up being delayed (for example, due to challenges related to siting, permitting or construction, or legal challenges related to contracting), then value of Millstone will similarly be increased relative to the results we have analyzed and reported here.

[63] CT DEEP, "Meeting of the Governor's Council on Climate Change (GC3), September 8, 2016," Page 10. http://www.ct.gov/deep/cwp/view.asp?a=4423&Q=568878&deepNav_GID=2121.

[64] Chris Nelder, James Newcomb, and Garrett Fitzgerald, "Electric Vehicles as Distributed Energy Resources," Rocky Mountain Institute, 2016, http://www.rmi.org/pdf_evs_as_DERs.

[65] Cost to load is equal to the annual sum of hourly energy prices multiplied by the total energy load, and represents the amount that all electricity consumers pay into wholesale energy markets.

[66] See Office of Management and Budget, Circular A-4, Issues September 17, 2003, at 33-37. Available: https://www.whitehouse.gov/omb/circulars_a004_a-4. All values are annualized in real terms. We use a 2-percent inflation rate to convert nominal dollars to real dollars.

[67] Under a higher, private discount rate of 7 percent, the total present value of economic benefits of Millstone to New England consumers would be more than $4.7 billion (NPV) by 2030.

[68] These values are based on average monthly residential bills as reported by EIA on Form 861. In 2015, the average Connecticut residential bill was $153.13, with an average total price of $0.2094/kWh and average monthly consumption of 731 kWh.

[69] See prior endnote.

[70] http://www.nrc.gov/info-finder/reactors/mill2.html; http://www.nrc.gov/info-finder/reactors/mill3.html.

[71] Our results assume that under the Clean Power Plan, RGGI would no longer have a cost containment reserve (with a concomitant release of additional allowances into the market), which would tend to limit price changes. Similarly, we do not model trading or banking of allowances across time or between RGGI and other states. For the period 2016 to 2021, we use the RGGI CO_2 allowance price floor of $2/ton (escalating at 2.5 percent annually). Under the existing model, and assuming the nominal cap on emissions, Aurora estimates that the shadow price for CO_2 would be below the floor. In contrast, shadow prices for the adjusted cap (net of banked allowances) produces a shadow price consistent with observed and current auction results. Our use of a lower, nominal CO_2 price in the 2016-2020 period is an example of one of the many conservative assumptions we have made in our analysis.

[72] In 2015, natural-gas-fired generation was on the margin and set electricity prices 75 percent of the time in New England. See ISO New England "Key Grid and Market Stats" https://www.iso-ne.com/about/key-stats.

[73] At the same time, higher gas prices may be passed on, or shared with, other interruptible service natural gas customers. In contrast, consumers depending upon firm natural-gas service, such as residential customers served by existing local distribution gas companies may not be affected by such price increases, or may stand to benefit through the resale of gas during periods of scarcity.

[74] See prior endnote describing the concerns of CT DEEP and ISO-NE:
http://www.ct.gov/deep/lib/deep/energy/ces/CES_Public_Scoping_Presentation_May_24_2016.pdf
https://www.electricitypolicy.com/News/iso-new-england-worries-about-reliability-post-2019.