Appendix A4- Financial Analysis

Introduction

DEEP has performed financial analysis of the Clean Energy Pathways delineated in the IRP. The highlights of the financial analysis are summarized in this section.

There are two load projections: Base Load Case and Electrification Load Case. There are five integrated resource portfolio cases:

- Reference Case, which reflects existing, business-as-usual energy policy that falls short of Governor Lamont's accelerated carbon reduction goals by 2040;
- Balanced Blend Case, which reflects a portfolio of zero carbon resources that meets Connecticut's carbon reduction goal;
- Solar Behind-the-Meter (BTM) PV Emphasis Case, which features additional and BTM Solar and likewise meets Connecticut's carbon reduction goal;
- Millstone Extension Case, which extends the operating life of both Millstone 2 and Millstone 3 beyond the current PPA expiration date in 2029 through 2040, and also meets Connecticut's carbon reduction goal; and,
- Transmission Case, which reflects the Balanced Blend Case without interface constraints within ISO-NE and meets Connecticut's carbon reduction goal.

The details associated with the definition of the Base Load Case, Electrification Load Case, and each of five integrated resource portfolio cases are presented in Appendix A1.

In this section, DEEP reports the cost differentials borne by Connecticut ratepayers, and society at large, under four resource policy cases in relation to the Reference Case. These costs are presented under both the Base Load Case and the Electrification Load Case. Each combination of a policy resource case underlying the featured technology under either the Base Load Case or the Electrification Load Case constitutes a scenario. Scenarios represent the union of the load projection case and the policy case that features different zero carbon resources prioritized by DEEP in performing this IRP. Both differential costs and benefits relative to the Reference Case have been derived over the planning horizon. The planning horizon is 2021 through 2040. The differential annual costs and benefits have been discounted to present value (PV) end-of-year 2020 as a reference point. The nominal discount rate is 7.00%. General inflation is 2.00% per year. The real discount rate is approximately 5%.

Unlike each of the integrated resource portfolio cases, the Reference Case is <u>not</u> constrained to meet Connecticut's goal of zero greenhouse gas emissions from the power sector by 2040. Hence, the Reference Cases under the Base Load and Electrification Load Cases fall short of realizing Connecticut's current carbon reduction goals.

This analysis facilitates standardized comparison of different means of achieving the emissions goal under distinguishable energy pathways. The Balanced Blend, Solar BTM PV Emphasis, and Millstone Extension Cases capture the costs and benefits of emphasizing various clean energy technologies. DEEP notes that direct costs related to case assumptions were measured for each of the three aforementioned integrated resource portfolio cases. The Transmission Case is different because DEEP has not included the transmission costs that would be required to accommodate large new injections of carbon free energy from resources in northern New England (land-based wind, Canadian imports, Grid PV), and southeast Massachusetts / Rhode Island (offshore wind). In effect, the Transmission Case renders New England a "copper sheet." Transmission constraints associated with the addition of land-based wind (LBW) in Northern New England have been documented by ISO-NE.[1]

Since no dollar cost estimate has been ascribed to the Transmission Case, the financial results should be interpreted as a measure of the benefits of reduced clean energy curtailments – and associated deferred generation investment – that could be obtained from improved transmission. This case is meant to yield insight into how flows from export-constrained regions would behave absent constraints in order to determine the discrete interface limit increases that would increase deliverability and reduce clean energy curtailments. The case also reveals the level of curtailment due to time-based weather coincidence rather than export constraints.

Cost and Benefit Categories and Items

To present the financial results in graphical form on a consistent basis, various cost and benefit items have been grouped. Cost and benefit groupings reflect direct and indirect components, including the avoided cost of alternative carbon free resources. The costs and benefits have been derived from Aurora wholesale market simulation model output. Other supporting models have been used as well for purposes of calibrating reliability metrics under NERC and NPCC reliability criteria and to define the requisite operating reserves needed to support different VER entry assumptions. More details about the modeling system and overall approach are presented in Appendix A1 and A2. In this subsection, DEEP defines the components of each category of cost and benefits.

Ratepayer Costs

The costs associated with implementing alternate zero carbon policies are borne by Connecticut ratepayers in two ways. First, costs can be incurred through the wholesale cost of energy supply due to both the changing costs of energy and capacity products. Second, costs can be incurred at the retail level through the inclusion of a non-by-passable surcharge administered by Connecticut's EDCs.[2] Hence, costs borne by ratepayers reflect changes in both wholesale and retail costs associated with the featured technologies in the array of scenarios. The direct costs of existing contracts for renewable/clean energy are paid for by all ratepayers through the non-bypassable surcharge. This also includes the direct costs associated with the Millstone PPA executed in 2019. Likewise, revenues received by the EDCs for the

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[1] See 2016/2017 Maine Resource Integration Study, Final Report, March 12, 2018, p.1. Western Maine Cluster: Cluster Interconnection System Impact Study, July 1, 2019, p.vi.
ISO-NE 2019 Regional System Plan, October 31, 2019, p 2.

[2] Federally Mandated Congestion Charge or "FMCC". The costs of many energy policy programs promoting zero carbon generation are paid for through the FMCC charge.

resale of energy and Renewable Energy Certificates (RECs) are credited to all ratepayers through the same non-bypassable surcharge.

The effects on wholesale market prices for energy and capacity, as well as RECs and ancillary services, are paid for by ratepayers through the supply charge. All load-serving entities (LSEs) in Connecticut must ultimately secure these products and price services to ratepayers accordingly.[3]

Incremental Resource Direct Cost

DEEP assumes that new zero carbon resources needed to meet the emission goals will be developed under contracts. Industry practice warrants a contract price in reasonable accord with the total revenue requirements of the associated resource project. Contracts covering *new* entry provide a predictable revenue stream, thereby allowing a developer to borrow money at a favorable rate since the seller of a zero-carbon resource would not be exposed to market, regulatory, or environmental risk. These revenue requirements, expressed as level constant dollar fixed costs, were developed for each candidate technology as a function of location and first year of operation, i.e., vintage. In reporting costs and benefits, the EDCs receive title to all products on behalf of Connecticut ratepayers, including energy, capacity, ancillary services, and environmental attributes.[4] In the case of the Millstone PPA Extension, the environmental attributes cover nearly 100% of Millstone's total output each year, even though the contract energy quantity envisioned under an extended Millstone PPA would be much lower.[5]

Items included in the Incremental Resource Direct Cost category include:

- Costs of an HQ Import project less costs for the same project in the Reference Resource Case;
- Costs of all BTM solar resources located in Connecticut under the policy resource case less the costs for Connecticut BTM resources under the Reference Case;[6]
- Costs of all utility-scale photovoltaic solar (PV), LBW, offshore wind (OSW), and storage resources, less the costs of the selected resources in the Reference Case;[7]

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[3] Adjustments for municipal load have not been incorporated in the cost and benefit categories.

[4] Uncertainty surrounding the realization of capacity revenues for carbon free resources under ISO-NE Buyer Side Mitigation Rules has not been explicitly accounted for in this study. DEEP continues to evaluate strategic risk considerations affecting the economic benefits and costs borne by ratepayers in Connecticut under existing FERC policy.

[5] This assumption is consistent with the existing long-term contract for Millstone Units 2 and 3, where Connecticut ratepayers purchase 9 million MWh of energy each year and also receive title to all environmental attributes associated with Dominion's ownership share, approximately 97%.

[6] These costs are incurred in part by the participating customer. The balance of the BTM solar resources are socialized through EDC program cost recovery.

[7] Each added resource is allocated between Connecticut and other states based on Connecticut's share of the total new resource requirement in each year. Each vintage retains its respective allocation in each subsequent year.

Millstone Extension Case Direct Cost

The direct costs for the Millstone Extension Case are a separate category. DEEP assumed a continuation of the status quo, meaning Dominion would enter a PPA with contract provisions approximately equal to the current PPA. The current PPA covers the sale of roughly 9 million MWh per year (9 TWh) per year from both Millstone 2 and Millstone 3. Consistent with the existing PPA, under the Millstone Extension Case, it is assumed that all environmental attributes are transferred to the EDCs on behalf of all ratepayers, which is equivalent to approximately 17 TWh per year. All capacity revenue belongs to Millstone. Assumed prices are generally consistent with the existing contract, but they have been adjusted for inflation to the extended PPA date commencing October 1, 2029.

Importantly, the current Millstone PPA is treated as an existing resource through September 30, 2029. Current PPA payments are therefore ignored since they are common to all scenarios and necessarily incurred by Connecticut's ratepayers in exchange for Millstone's continued operation through 2029.

Incremental Resource Market Value

Energy and capacity revenues associated with each incremental resource are obtained through Aurora.

Energy revenues are calculated hourly for each resource and allocated to Connecticut and/or other New England states. In all cases except the Millstone Extension Case (the only Case where the HQ Line is not built), Connecticut receives 100% of the revenue benefits from the HQ import line. Connecticut also receives its assigned share of each PV, LBW, OSW, or storage resource by vintage. Differences are calculated on the aggregate amounts between each Policy Resource Case and the corresponding Reference Case.

Energy revenues for incremental BTM resources in Connecticut are estimated based on the average revenue rate of a utility scale PV project located in Connecticut. While this revenue stream is less than the retail-based revenue of the participating BTM customer, it is an estimate of the net benefit to Connecticut customers in the aggregate. While there may be some avoided distribution costs associated with BTM solar, including reduced distribution losses, the retail rate paid to participants for energy generated includes the unitized fixed distribution costs that are not avoided. This treatment is applicable irrespective of BTM avoiding grid purchases or being exported to the grid.

Like energy revenues, capacity revenues are calculated annually for each resource and allocated to Connecticut or other New England states. Connecticut receives 100% of the revenue benefits from the HQ import line (in applicable resource cases) and its assigned share of each PV, LBW, OSW, or storage resource by vintage.[8] Differences are calculated on the aggregate amounts between each Policy Resource Case and the corresponding Reference Case.

[8] Currently, many of Connecticut's contracted resources do not receive capacity revenues. This is because they have elected not to participate in ISO-NE's FCA or they have not cleared the capacity market. This analysis assumes that contracted resources receive capacity revenues. The capacity clearing quantities have been modeled dynamically in Aurora. Over time, capacity contributions from VERs degrade, as they effectively reset peak hours.

Millstone Extension Market Value

Market energy revenues associated with the Millstone Extension Case are allocated to the Connecticut EDCs based on the PPA share of about 9 TWh per year. This represents approximately 55% of Millstone's annual output on average.[9] Millstone retains the energy revenue from the sale of energy not covered by the PPA. Assuming a continuation of Millstone's Capacity Supply Obligation through 2040, Millstone retains all capacity revenue in ISO-NE's FCM and/or through bilateral sales.[10]

Revenue Effects on Existing Contracts

The Connecticut EDCs have a portfolio of existing PPAs with renewable and clean energy resources that continue through part or all of the IRP study period. This is a common convention under all scenarios. The revenues from the energy procured under these PPAs is affected by market prices. In some instances, output curtailments occur in different scenarios. The effects are captured at the hourly level and aggregated by Aurora to the annual level for each resource. For resources where Connecticut EDCs have only partially contracted with an existing resource (such as Millstone), a pro rata share of energy revenue was calculated. Differences in contracted resources' energy revenues were calculated between the Policy Resource cases and the relevant Reference Case for each scenario. None of the existing PPAs between Connecticut EDCs and various sellers include the sale of capacity.

Wholesale Market Price Effects

The different resource mix among the scenarios result in different levels of market energy and capacity pricing that eventually flow to ratepayers through the energy supply charge. The same wholesale energy price effect happens regardless of a ratepayer's decision to purchase Standard Service from Connecticut's EDCs, or from competitive retail suppliers.

The energy price effect is captured in Aurora by totaling the hourly products of energy price and load by zone. The financial model calculates the differential cost between each Policy Resource Case and the corresponding Reference Case.

A similar calculation is performed on an annual basis for the market cost of capacity to serve load. The financial model calculates the differential cost between each Policy Resource Case and the corresponding Reference Case.

Societal Cost of GHG Effects

While each Policy Resource Case has been designed to achieve Connecticut's 2040 zero carbon goal, there are differences in annual CO_2 emissions assignable to Connecticut in the earlier years of the IRP study period. These differences, which may be positive or negative relative to the annual targets, are valued at

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In the case of solar, the calculation accounts for the "duck curve effect". All financial results assume that capacity revenues for existing contracted resources are retained wholly by seller.

[9] Millstone is refueled on an 18-month cycle, so output varies based on staggered unit outages.

[10] Potential structural changes to the FCM, including the impact of Buyer Side Mitigation to state sponsored carbon free resources, have not been addressed in this analysis.

the social cost of carbon less the RGGI carbon price embedded in energy prices.[11] This cost or benefit does not flow to ratepayers. Instead, it is deemed a societal cost that must be included in the comparison of long-term policies.

The financial model uses a simplified, consumption-based inventory model to assign contracted zero-carbon resource production against CO_2 emission avoidance goals.[12] To determine the annual societal cost under each scenario, differences between the contracted annual zero-carbon resource output for each Policy Resource Case and its corresponding Reference Case are multiplied by the avoidance rate and by the net social cost of carbon.

Allocation of Incremental Resources

The Aurora model determined a total cost-minimizing sequence of incremental zero-carbon resource additions, subject to various static adjustments to resources made in the resource policy cases.[13] Aurora could select from candidate resources such as Grid PV, OSW, LBW, additional HVDC ties, and battery storage to meet regional carbon goals and resource adequacy requirements.

For the Reference Cases under the Base Load and Electrification Load cases, resources were added to align with existing regional RGGI requirements, rather than the much more stringent proposed carbon reduction goals. These resources were allocated among the states based on load share.

For the Policy Resource Cases, the additions for each year (or vintage) were allocated between Connecticut and the other New England states in proportion to Connecticut's carbon reduction needs in 2040. Each "incremental" resources selected by Aurora over the study period was allocated between Connecticut and the other states at the ratio of Connecticut's 2040 need (energy load less the output of all other zero carbon resource assigned to Connecticut) to the total energy 2040 output of all selected regional incremental resources, regardless of vintage. This allocation factor was then applied to each resource in every year to determine Connecticut emission inventory, incremental resource direct cost, and incremental resource market revenue.[14]

[11] Projected CO2 allowance prices are based on the RGGI Model Rule Policy Scenario forecast prices that were prepared on behalf of the 2017 RGGI Program Review conducted by the RGGI Stakeholder Group. As discussed in Appendix A1, RGGI prices were extrapolated to continue the trend in the current program review. Prices beyond 2031 were escalated by applying the growth rate observed in the program review prices.

[12] All state-assigned zero-carbon resource output is assumed to avoid New England regional emissions at a rate of 800 lb/MWh (0.363 metric ton/MWh).

[13] Static adjustments include either extension of Millstone or new HVDC tie line and BTM PV growth assumptions.

[14] The selected allocation method results in an exact match between the output of Connecticut-assigned zero-carbon resources and Connecticut load in 2040. Connecticut is either long or short in other years. Given the lumpiness of resource additions in Aurora, it was not feasible to determine a vintage-by-vintage or resource-by-resource allocation that would result in an exact match each year over the IRP study horizon.

The Connecticut allocation ratio calculations for the Base Load Case policy case scenarios are shown in Table 1. The same calculations are shown for the Electrification Load Case policy case scenarios are shown in the following table.

Table 1: Incremental Resource Allocation Ratios – Base Load Case Scenarios

	Base Load Case			
Policy Resource Case	**Balanced Blend**	**Solar BTM PV Emphasis**	**Millstone Extension**	**Transmission**
2040 Resource Balance (GWh)				
CT Energy Load				
Net Load	30,851	29,386	30,851	30,851
Dispatchable EV Charging Load	0	0	0	0
BTM Solar	2,710	4,189	2,710	2,710
Gross Load	33,561	33,575	33,561	33,561
CT Zero-Carbon Resource				
Existing Contracts	3,830	3,659	3,974	3,990
HQ Imports	7,029	7,031	0	7,029
Millstone Extension			16,918	
BTM Solar	2,710	4,189	2,710	2,710
Total (Excluding Incremental*)	13,570	14,880	23,602	13,729
Required Incremental Resources	19,991	18,695	9,959	19,832
Regional Incremental Resources	39,731	36,025	29,234	40,406
CT Allocation Ratio	50.32%	51.89%	34.07%	49.08%

* Incremental resources are zero-carbon resources selected in the Aurora simulation.

Table 2: Incremental Resource Allocation Ratios – Electrification Load Case Scenarios

	Electrification Load Case			
Policy Resource Case	**Balanced Blend**	**Solar BTM PV Emphasis**	**Millstone Extension**	**Transmission**
2040 Resource Balance (GWh)				
CT Energy Load				
Net Load	30,145	28,680	30,145	30,145
Dispatchable EV Charging Load	5,983	5,983	5,983	5,983
BTM Solar	2,710	4,189	2,710	2,710
Gross Load	38,838	38,852	38,838	38,838
CT Zero-Carbon Resource				
Existing Contracts	3,694	3,681	4,029	3,929
HQ Imports	7,032	7,033	0	7,033
Millstone Extension			16,918	
BTM Solar	2,710	4,189	2,710	2,710
Total (Excluding Incremental*)	13,436	14,902	23,657	13,672
Required Incremental Resources	25,402	23,950	15,181	25,166
Regional Incremental Resources	54,691	49,883	41,555	54,136
CT Allocation Ratio	46.45%	48.01%	36.53%	46.49%

* Incremental resources are zero-carbon resources selected in the Aurora simulation.

Base Reference Scenario

Figure 1 shows the annual regional resource additions selected by Aurora for the Base Reference Scenario, excluding the addition of a 1,000 MW HVDC HQ Import line. Other than the Import link to Quebec, the resources were allocated to Connecticut based on annual load share based on regional load, which is about 24%. Figure 2 shows the annual energy allocation from the cumulative Connecticut resource allocation. Note that the energy contribution from the storage resources is small and negative. The negative contribution from storage reflects the losses incurred in shifting delivery time.[15]

[15] CT's share of each vintage incremental resource is based on the need to meet the target inventory for that year. The share percentage is assigned to all resources in the vintage, and that share of direct costs and direct revenues (energy and capacity) flow to CT. The annual energy is negative, but the annual energy revenue is generally positive for storage resources.

Figure 1. Incremental Capacity Additions – Base Reference Scenario

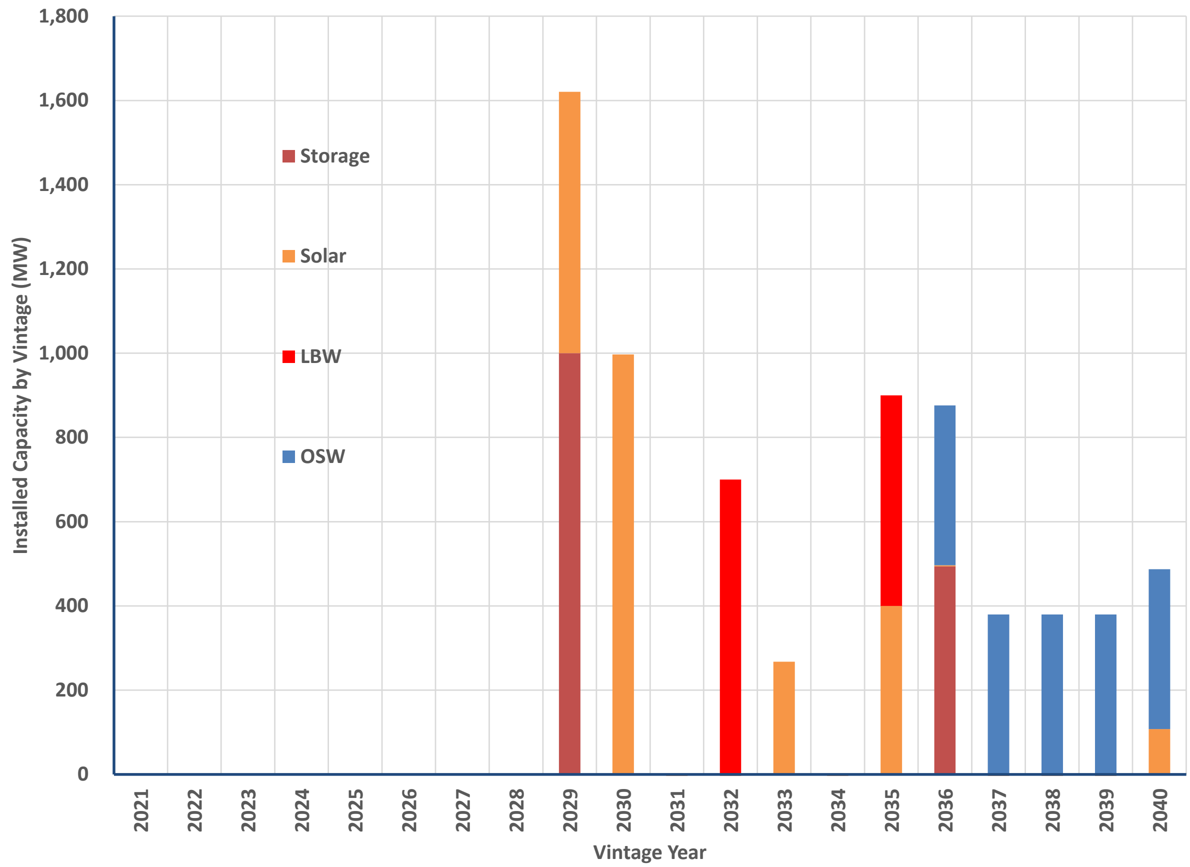
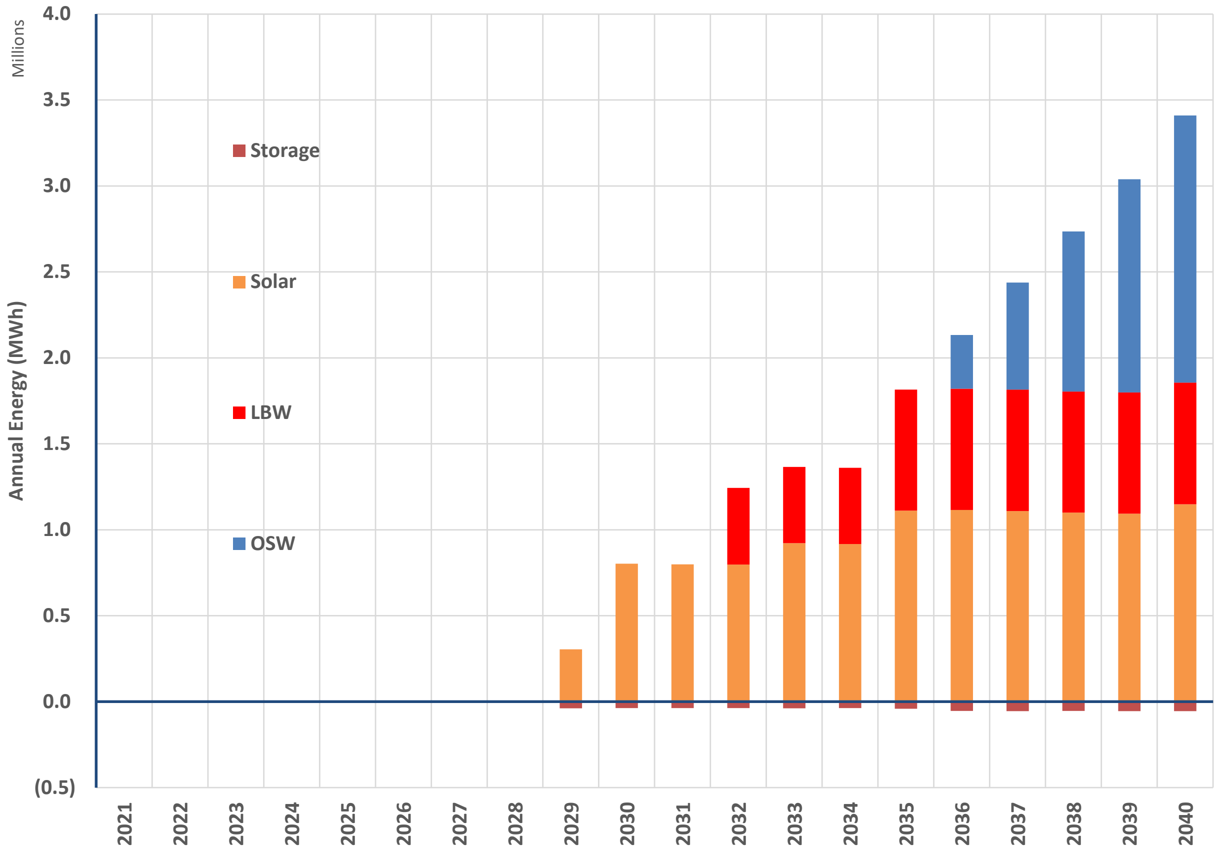


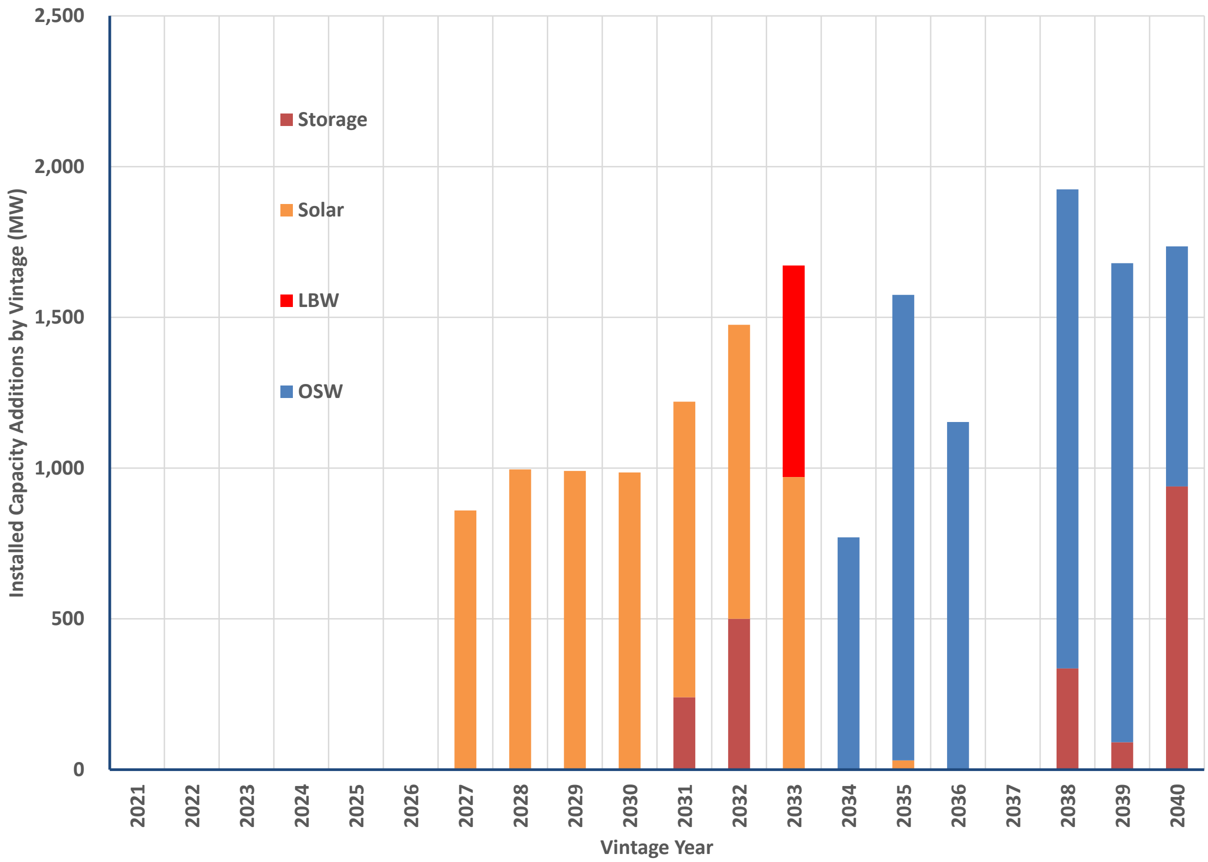
Figure 2. Connecticut Energy Allocation from Incremental Resources - Base Reference Scenario



Base Balanced Blend Scenario

For the Base Balanced Blend Scenario, the incremental resources -- other than the import link and BTM solar -- are allocated based on Connecticut's 2040 carbon reduction needs. Figure 3 below shows the total incremental resource capacity additions. The installed capacity additions by vintage are shown on the y-axis. Connecticut is allocated 50.32% of each resource in each vintage.

Figure 3. Incremental Resource Capacity Additions by Vintage – Base Balanced Blend Scenario

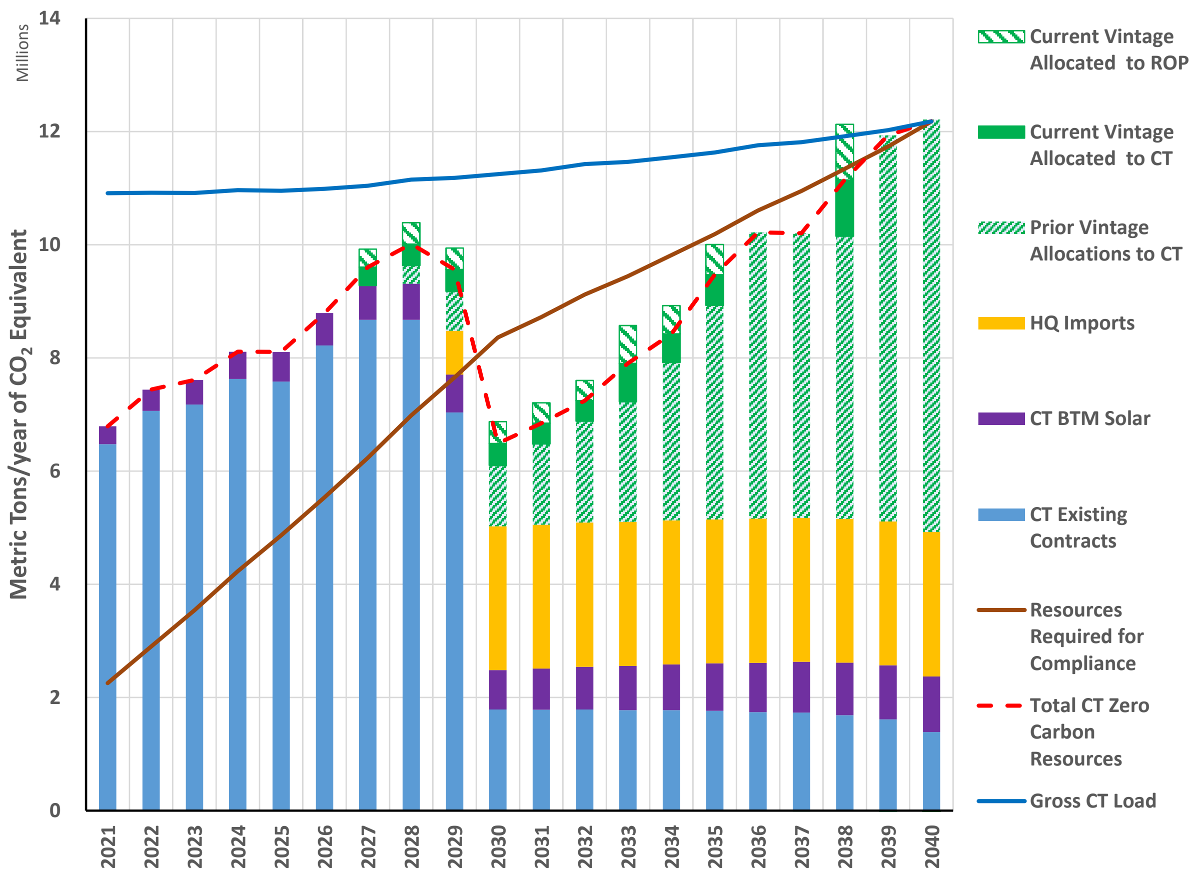


Resulting energy allocations by calendar year are shown if Figure 4. These reflect the cumulative effect of each vintage addition, so that, in later years, the energy shown is a mix of that year's vintage additions and the outputs from all previous vintages. From left to right, the upward sloping brown line shows the amount of zero carbon resources required to meet Connecticut's annual targets for CO_2 emission inventory. This amount is expressed in metric tons per year. The conversion rate is 0.363 MT/MWh. The bars in the chart represent the following:

- Existing Contracts: The light blue bars represent resources already under contract, including Millstone through September 2029.
- BTM Solar: The purple bars represent the pre-determined amounts of BTM solar for the case, as discussed in more detail in Appendix 1 and Appendix 3.
- Policy Resources: The yellow bars represent the Import line from Quebec, which enters service in October 2029. The import line from Quebec is a partial replacement for Millstone because the total import capability is much less than Millstone's annual output.
- Prior Allocations: The pale green bars represent the cumulative allocations of incremental resources needed to meet the zero carbon goal for Connecticut from prior years.
- Incremental to CT/Incremental to Others: The solid green bars represent the allocation to Connecticut of the current year vintage incremental resources (utility scale solar, LBW, OSW, and storage). Incremental resources not allocated to Connecticut are shown as hatched green bars

for each vintage year. Note that the allocated incremental resources are insufficient to meet Connecticut's needs in 2030, through 2038. There were no incremental additions in 2037 or 2038. This approach did not assume rigid adherence to intermediate carbon goals. Shortfalls are in large part due to the significant drop in contracted clean energy that occurs when Millstone retires, which has an outsize impact on Connecticut GHG accounting compared to the regional goals that determined Aurora's resource selection.

Figure 4. Connecticut Allocation of Incremental Resources – Base Balanced Blend Scenario



The allocation factor is used to assign energy and capacity revenues and annual fixed costs to the Connecticut share of each incremental resource.

This process is applied to each scenario to support the financial analysis. Detailed results for other scenarios are presented in Appendix 3.

Scenario Results

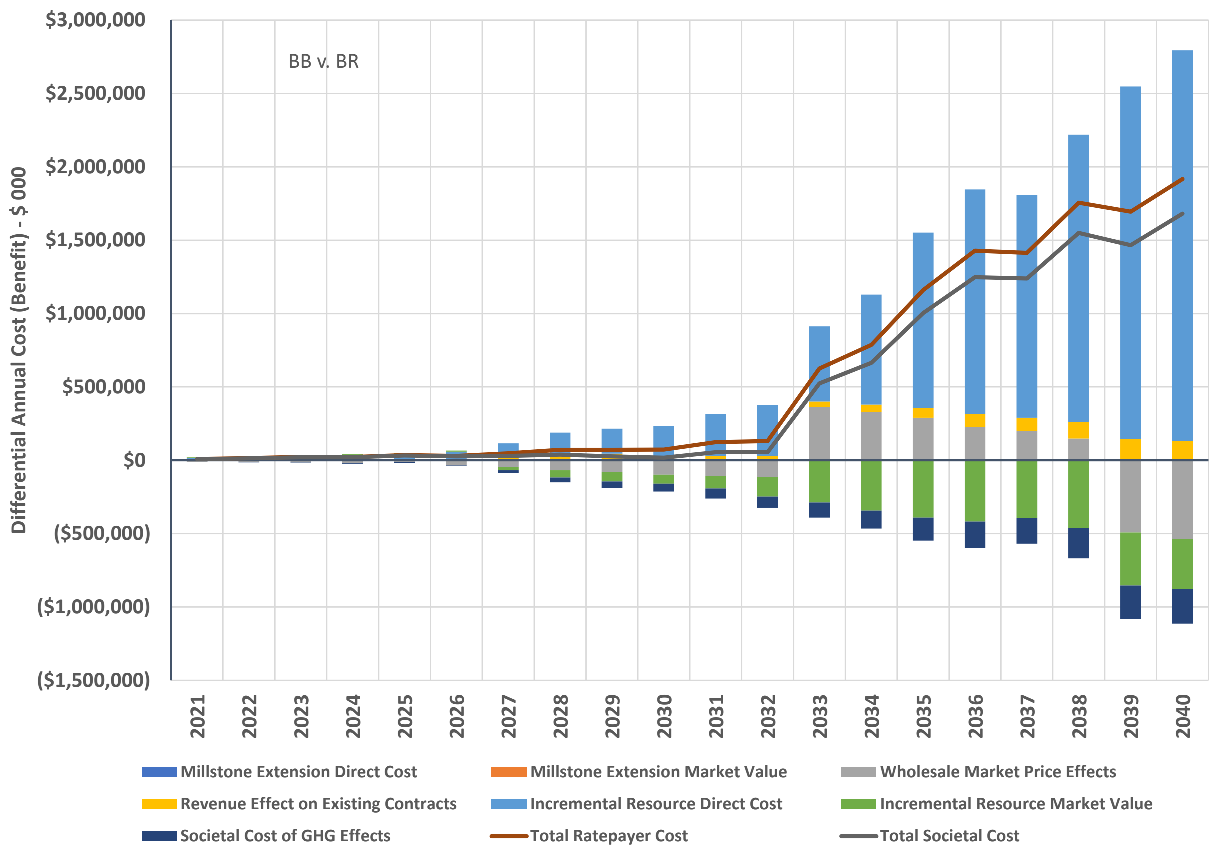
Results of the financial modeling are presented below. There are three stages. The first stage considers the Balanced Blend Resource Case against the Reference Resource Case for either the Base Load Case or the Electrification Load Case. This establishes a baseline for comparison with the other Resource Cases. The second stage looks at each alternative Resource Case in terms of differentials relative to the Balanced Blend Resource Case. The third stage compares all Resource Cases.

Balanced Blend Case versus Reference Case

Base Load Case

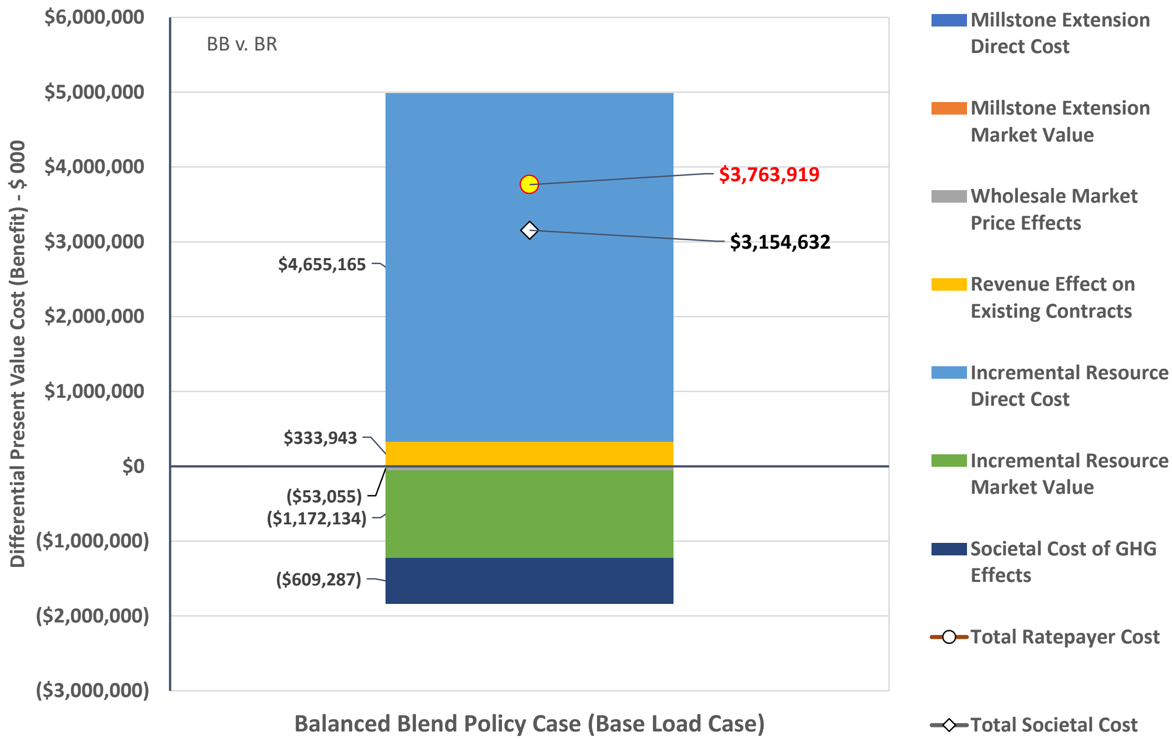
Annual differential costs for the Balanced Blend Case against the Reference Case are shown in Figure 5. Differences are negligible for the first several years. Beginning in 2028, the net cost of incremental resources becomes significant as ratepayer costs climb above zero and steadily ascend. The increase is partially offset by the negative societal cost associated with a reduction in CO_2 emissions.

Figure 5. Differential Annual Costs – Balanced Blend v. Reference (Base Load Case)



The present value of the differential costs is summarized in Figure 6. The net cost to Connecticut ratepayers to purchase incremental resources needed to achieve the zero carbon goal over the study period under the Base Balanced Blend scenario is $3.8 billion. This figure does not represent the total cost of achieving the 2040 zero carbon goal because it does not incorporate the full cost of demand side programs included in the Balanced Blend and all other Resource Cases. The differential in direct benefits (Incremental Resource Market Value) between the Balanced Blend and the Reference Case accounts for approximately $1.2 billion. This captures the value of energy and capacity revenues associated with the zero carbon resources, i.e., a credit to load. The societal benefit from GHG reduction of $0.6 billion constitutes the difference between Net Societal Cost and Net Ratepayer Cost.

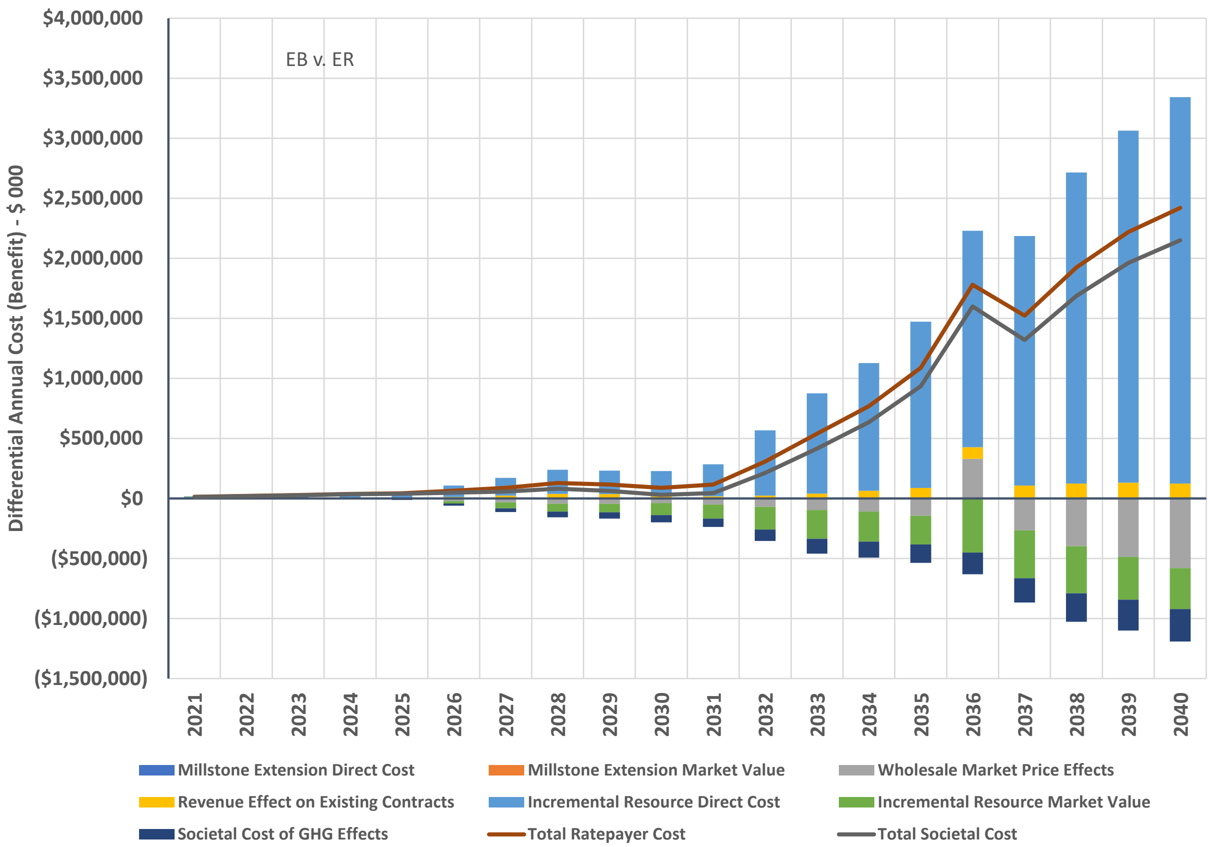
Figure 6. Differential PV Costs - Balanced Blend v Reference (Base Load Case)



Electrification Load Case

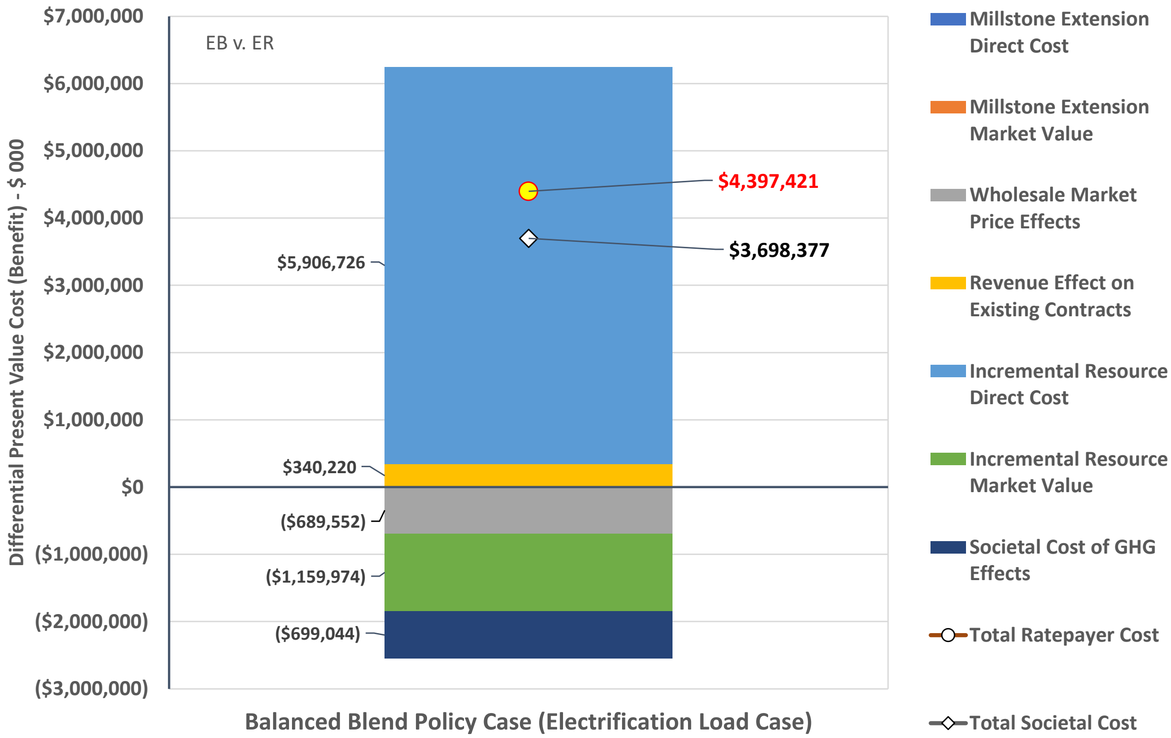
Annual differential costs for the Balanced Blend Case against the Reference Case paired with the Electrification Load Case are shown in Figure 7. Differences are negligible for the first several years. Again, beginning in 2028, the net cost of incremental resources increases as ratepayer costs (the red line) climb above zero. The increase is partially offset by the societal cost associated with a reduction in CO_2 emissions (dark blue bar below the x-axis). The general trend continues through 2040.

Figure 7. Differential Annual Cost – Balanced Blend v. Reference (Electrification Load Case)



The present value of the differential costs is summarized in Figure 8. The net cost to Connecticut ratepayers to purchase incremental resources needed to achieve the zero carbon goal over the study period under the Electrification Balanced Blend scenario is $4.4 billion. This figure does not represent the total cost because it does not include the full cost of demand side programs implemented in the Balanced Blend and all other Resource Cases other than the Reference Case. The largest offsetting benefit is the $1.2 billion in direct benefits from the market value of the incremental resource capacity and energy. Favorable wholesale price effects ascribable to the large buildout of zero carbon resources amount to about $0.7 billion, while societal benefits from carbon reduction amount to about $0.7 billion.

Figure 8. Differential PV Costs - Balanced Blend v. Reference (Electrification Load Case)



Policy Resource Cases vs. Balanced Blend Case

Behind-the-Meter Solar PV Emphasis Case

The BTM Emphasis Case incorporates significantly more incremental BTM solar PV capacity. The additional BTM capacity begins in 2021. The addition of BTM allows for a reduction in Aurora-selected incremental resources over the study period that would otherwise confer like environmental benefits.[16] In this policy resource case, BTM was added in all states in relation to the Balanced Blend Case. Both the differential costs and benefits are accounted for in the financial model for Connecticut. The incremental zero carbon energy production in Connecticut is included in the GHG inventory calculations that determine Connecticut's share of each year's Aurora-selected incremental resource additions.

Details of the allocation calculations are also provided in Appendix A1.

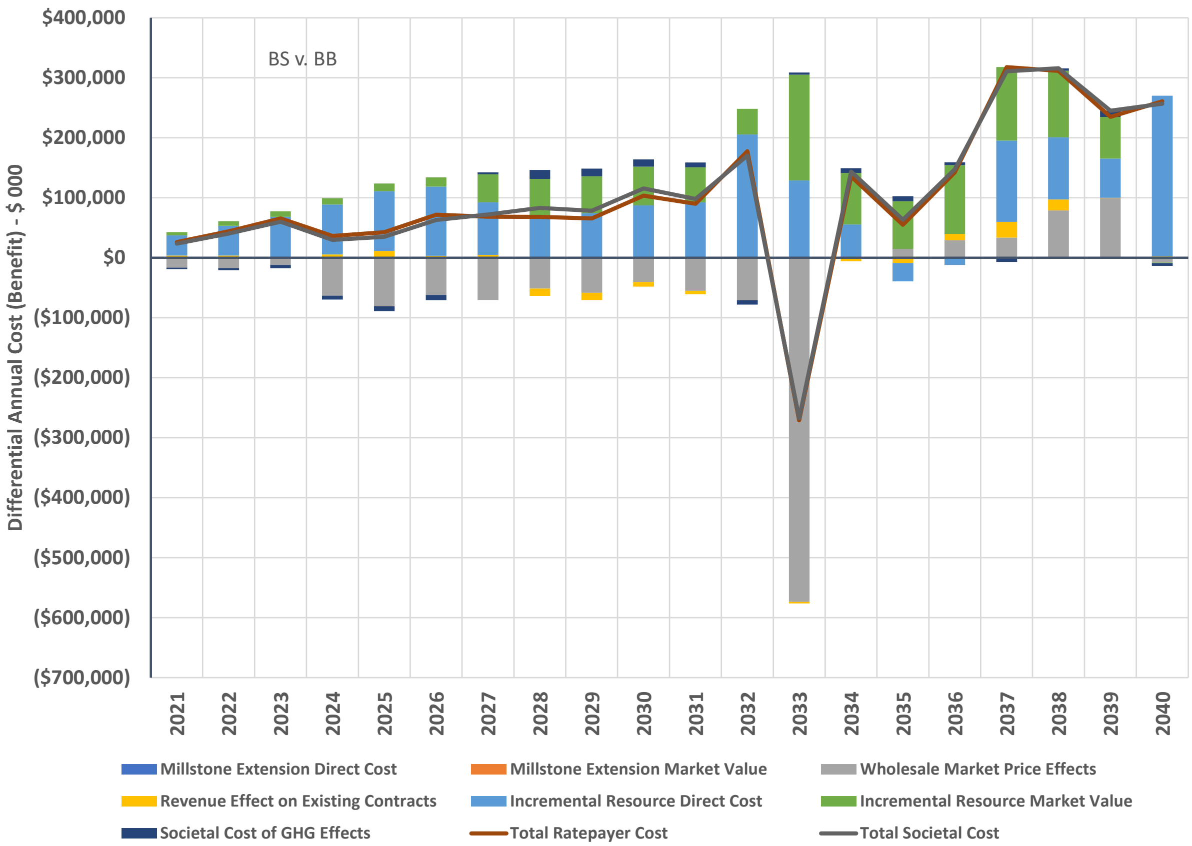
Base Load Case Results

Annual differential costs for the Base BTM Emphasis Scenario, relative to the Base Balanced Blend Scenario are presented in Figure 9. Costs in most years are dominated by the incremental resource costs (light blue bars), which include the gross costs of the added BTM resources in Connecticut. These costs are incurred from 2021 forward. The green bars represent the differential revenue from all incremental resources, while the gray bars represent energy and capacity market price effects on cost-to-load. The large Wholesale Market Price Benefits value in 2033 was driven by capacity prices. Under the BTM case,

[16] See Appendix A1, section 6.3, for more details regarding the formulation of the BTM Emphasis Case.

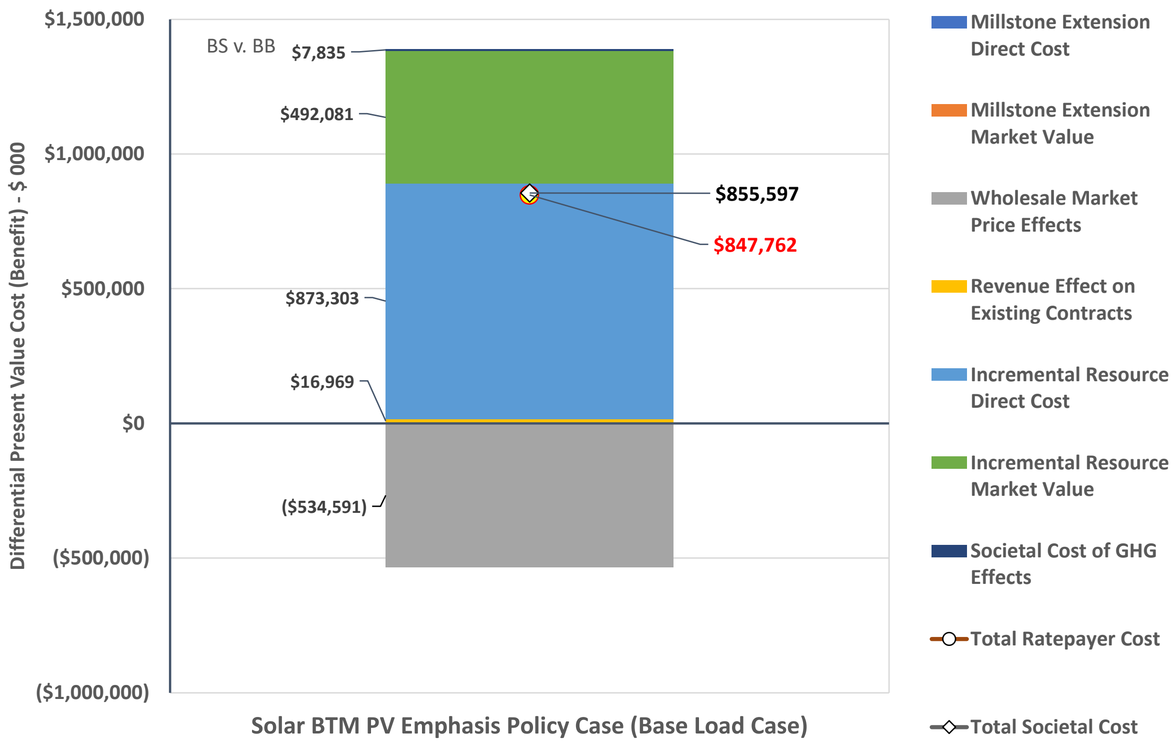
the year which battery resources became the marginal resource (and capacity prices significantly increase) was deferred from 2032 to 2033.

Figure 9. Differential Annual Costs - BTM Emphasis Case (Base Load Case)



The differential present value costs for the Base BTM Emphasis Scenario are shown in Figure 10. Results for the Base BTM Emphasis Scenario show $0.9 billion in additional net ratepayer costs relative to the Base Balanced Blend Scenario. This is driven primarily by about $0.9 billion in incremental resource fixed costs, including the participants' share. Another important component of the total ratepayer cost burden is the net loss of approximately $0.5 billion in market value of incremental resource products, while ratepayers see a $0.5 billion benefit from reduced market price effects. Cost differentials in all other categories are minimal.

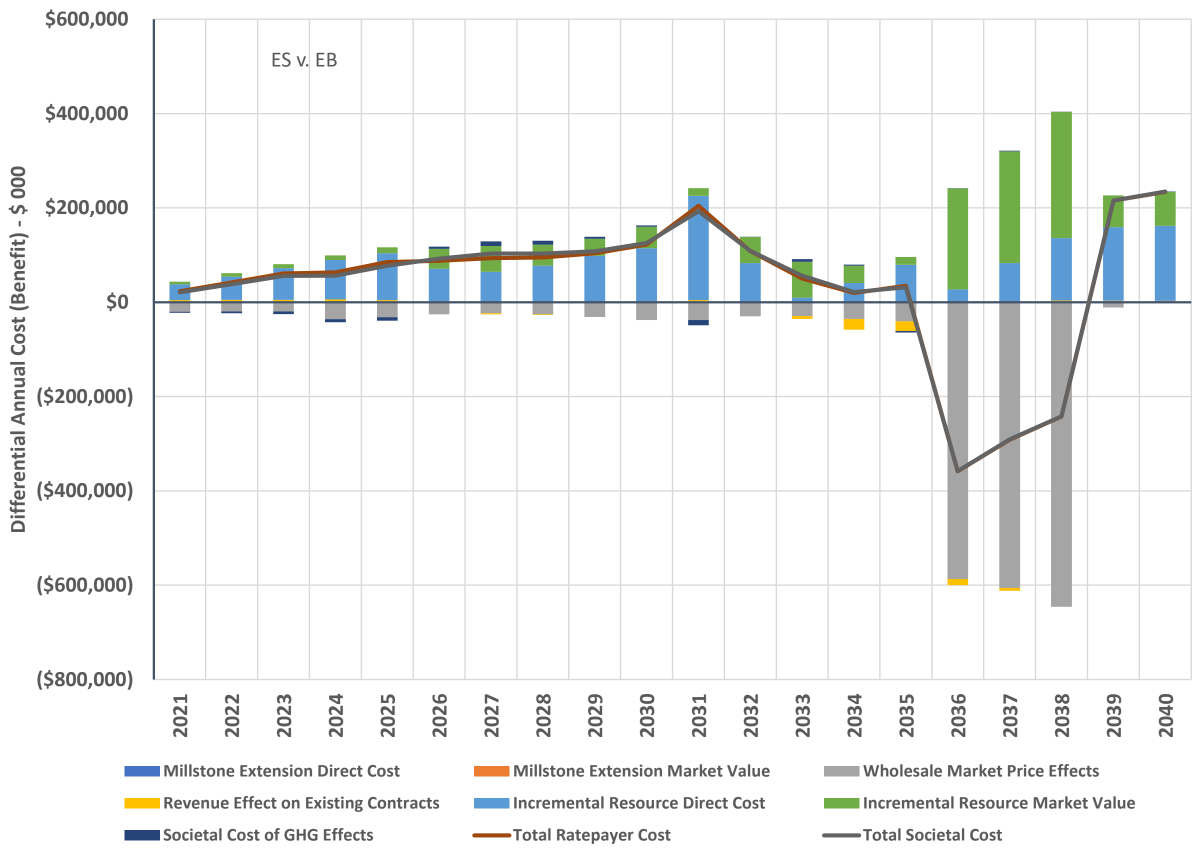
Figure 10. Differential PV Costs - BTM Emphasis Case (Base Load Case)



Electrification Load Case

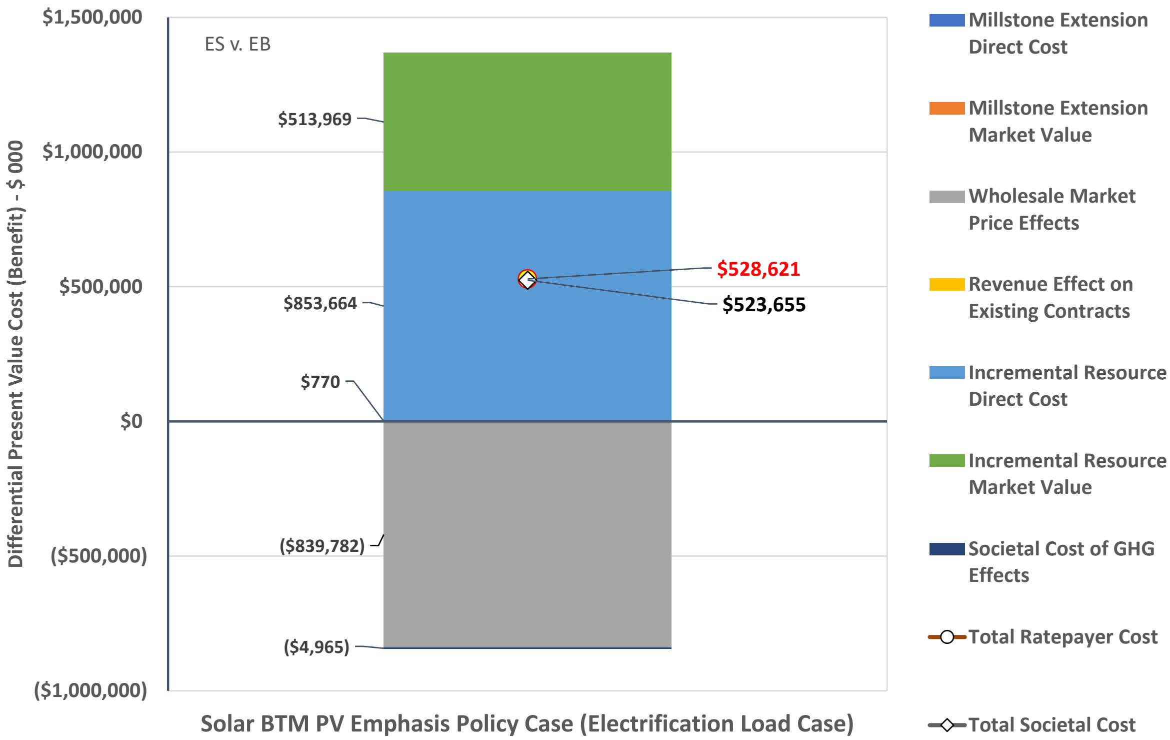
Annual differential costs for the Electrification BTM Emphasis Scenario, relative to the Electrification Balanced Blend Scenario, are presented in Figure 11. Costs in most years are dominated by the incremental resource costs (light blue bars), which include the gross costs of the added BTM resources in Connecticut. These costs are incurred from 2021 on, but they are reversed from 2032 through 2034. The gray bars represent energy and capacity market price effects on cost-to-load. Cost to load benefits increase significantly from 2036 to 2038 due to capacity price difference, in manner similar to the like Base Load Cases.

Figure 11. Differential Annual Costs - BTM Emphasis Case (Electrification Load Case)



The differential present value costs for the Electrification BTM Emphasis Scenario are shown in Figure 12. Results for the Electrification BTM Emphasis Scenario show $0.5 billion in additional ratepayer costs relative to the Electrification Balanced Blend Scenario. This is driven primarily by about $0.9 billion in incremental resource direct costs and $0.5 billion in reduced incremental resource market revenue, offset by $0.8 billion in favorable market price effects.

Figure 12. Differential PV Cost - BTM Emphasis Case (Electrification Load Case)



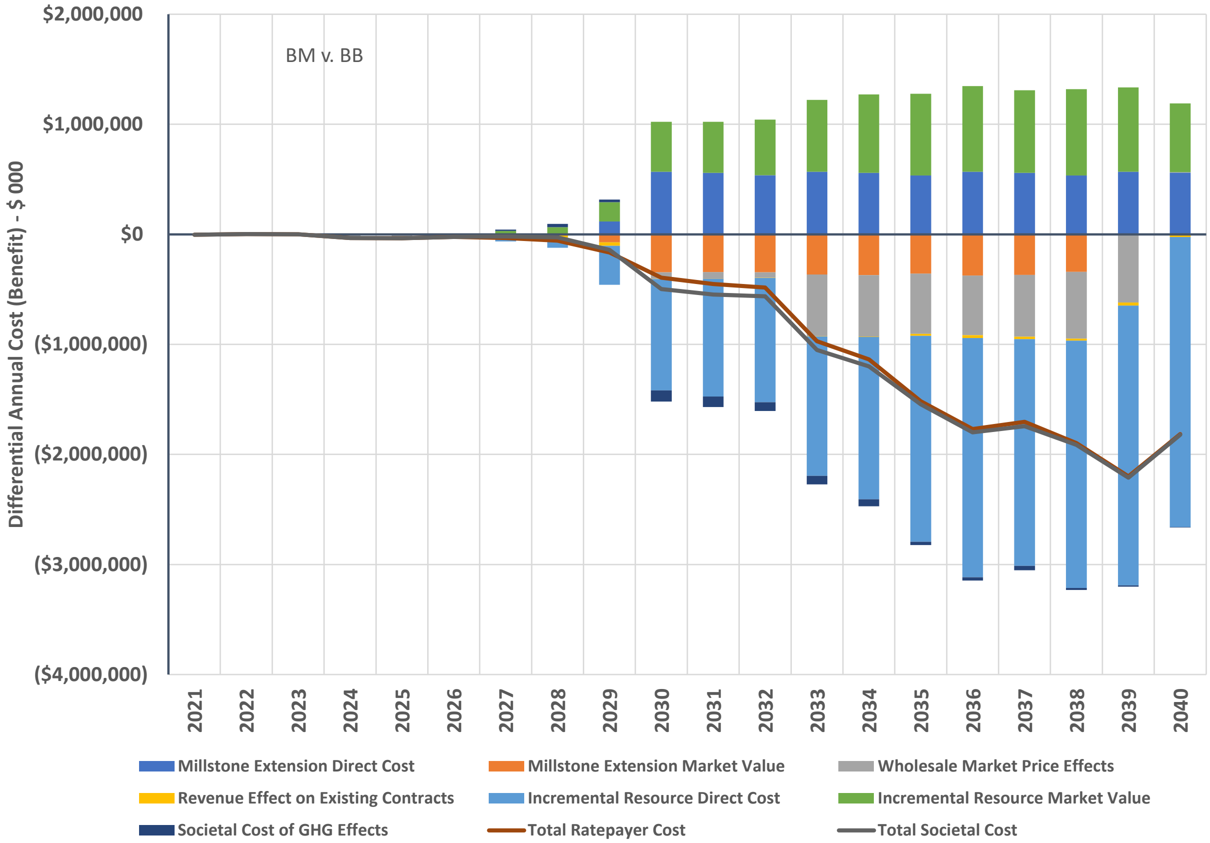
Millstone Extension Case

The Millstone Extension Case assumes that the existing PPA is extended through 2040 under the same commercial provisions. Extending the Millstone PPA avoids the need for the additional Import Line project from Quebec. The resource capacity adder in Aurora was used to optimize the addition of other resources.

Base Load Case

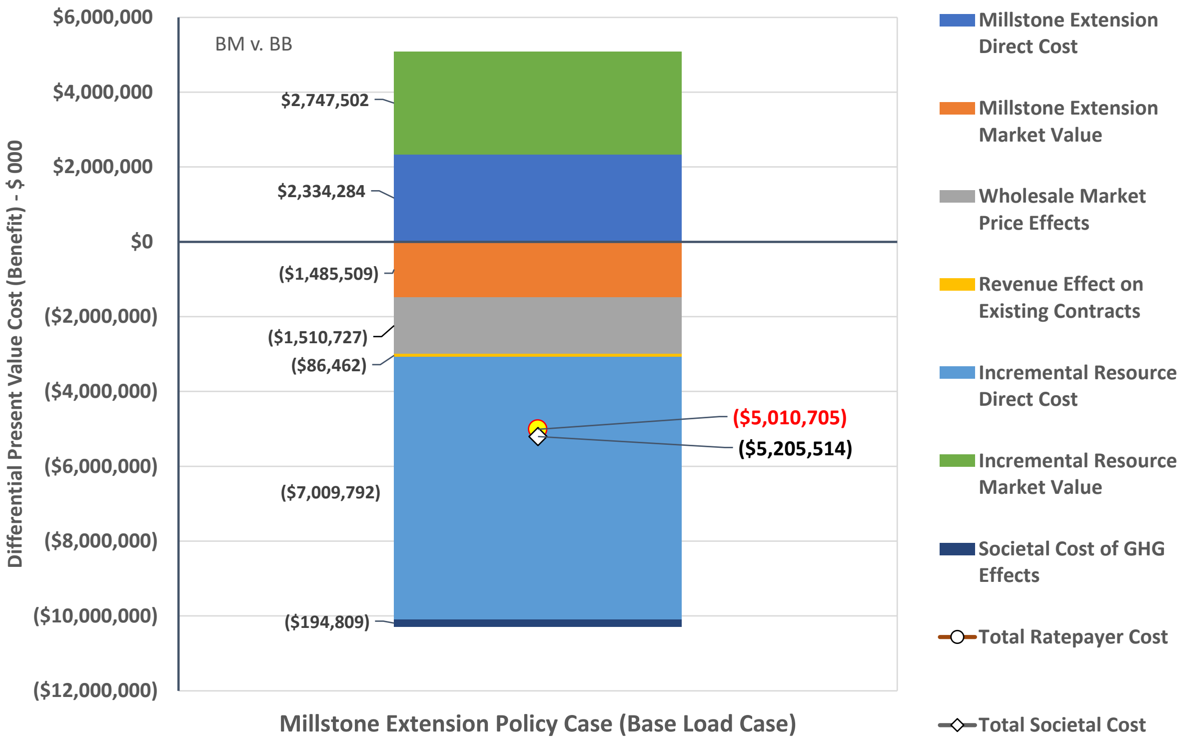
The Base Millstone Extension Scenario shows little change from the Base Balanced Blend Scenario through 2028, as seen in Figure 13. In 2029, the net cost is negative, meaning the projected cost of a Millstone extension at the assumed contract price is less than the projected cost of other zero carbon resources Connecticut ratepayers would incur if Millstone were to retire in 2029. The primary negative cost elements are the cost of incremental resources (light blue bars) and the market value of the energy sold under the extended Millstone PPA (orange bars). On the positive cost side, the most significant elements are the above market payments for contract energy under the PPA, shown in darker blue, and the forgone energy and capacity revenues from the avoided incremental resources. From the inflection point in 2029, the downward sloping brown line representing net ratepayer cost shows substantial economic benefits attributable to the avoidance of more expensive zero carbon free resources.

Figure 13. Differential Annual Costs - Millstone Extension Case (Base Load Case)



As seen in Figure 14, the present value bars show the same relationships as the annual cost bars. The present value of Net Ratepayer Cost is negative ($5.0 billion), reflecting a large ratepayer benefit in relation to the Base Balanced Blend Scenario. The present value of extended Millstone PPA payments is $2.3 billion, while the forgone incremental resource revenues have a present value of $2.7 billion. These costs are offset by $7.0 billion of the avoided costs associated with more expensive zero carbon resources in the Base Balanced Blend Scenario. Also, there is about present value $1.5 billion in anticipated revenues from the resale of the contract quantity of Millstone energy and another $1.5 billion in market price benefits.

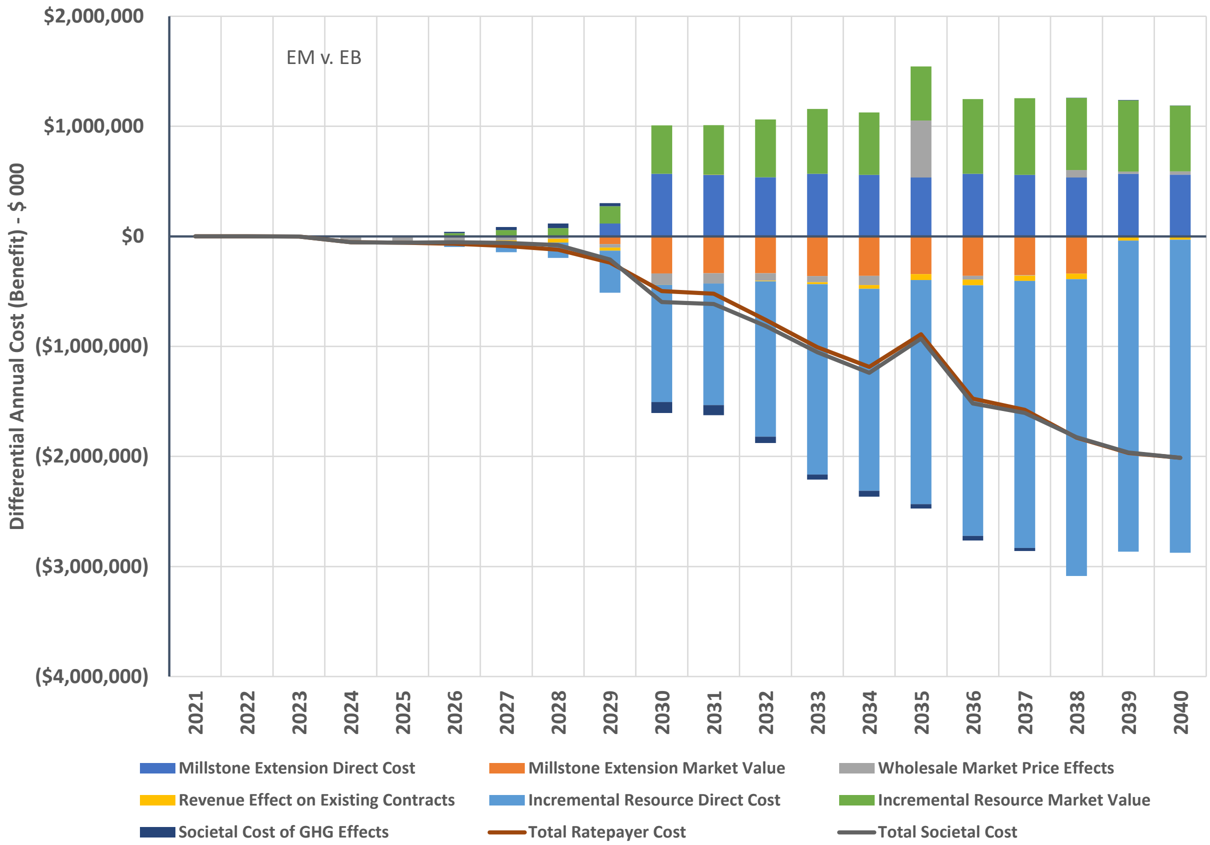
Figure 14. Differential PV Costs - Millstone Extension Case (Base Load Case)



Electrification Load Case

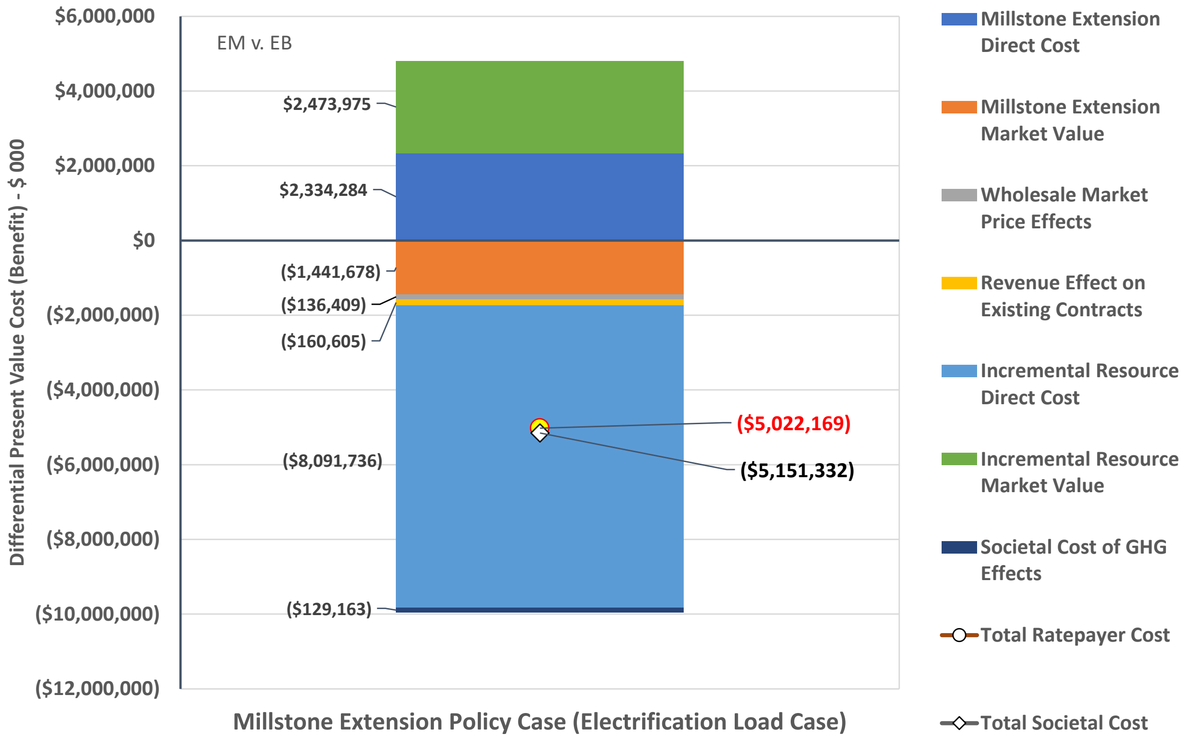
The Electrification Millstone Extension Scenario annual benefits, as shown in Figure 15, are similar to those under the Base Millstone Extension Scenario (Figure 13), with annual net benefits generally increasing after 2028.

Figure 15. Differential Annual Costs - Millstone Extension Case (Electrification Load Case)



In present value terms, the Electrification Millstone Extension Scenario shows a Net Ratepayer Benefit of $5.0 billion under in Figure 16. The present value of Millstone PPA payments is $2.3 billion (as in the Base Load Case). The forgone incremental resource revenues amount to about $2.5 billion. The avoided cost of incremental resources has a present value of $8.1 billion. Revenues from the resale of Millstone PPA energy have a present value of $1.4 billion. Market price effects were negligible under the Base Load Case, and they remain so under the Electrification Load Case.

Figure 16. Differential PV Costs - Millstone Extension Case (Electrification Load Case)



Transmission Case

The Transmission Case begins with the same resource base as the Balanced Blend Case. However, constraints on energy transfer among New England zones are relaxed in Aurora. This is tantamount to a "copper sheet" across New England where intra-RTO congestion between RSP zones is eliminated over the IRP study horizon. The No Transmission Constraint Case results in less curtailment of some resources and the reduced or deferred need for various incremental resources. Costs for such resources are thus reduced.[17] As mentioned earlier, costs for transmission upgrades were not estimated for the No Transmission Constraint Case. Thus, the net ratepayer benefit and net societal benefit should be viewed within this context and the ultimate net benefits would depend upon the cost of solution(s) alleviating transmission constraints.

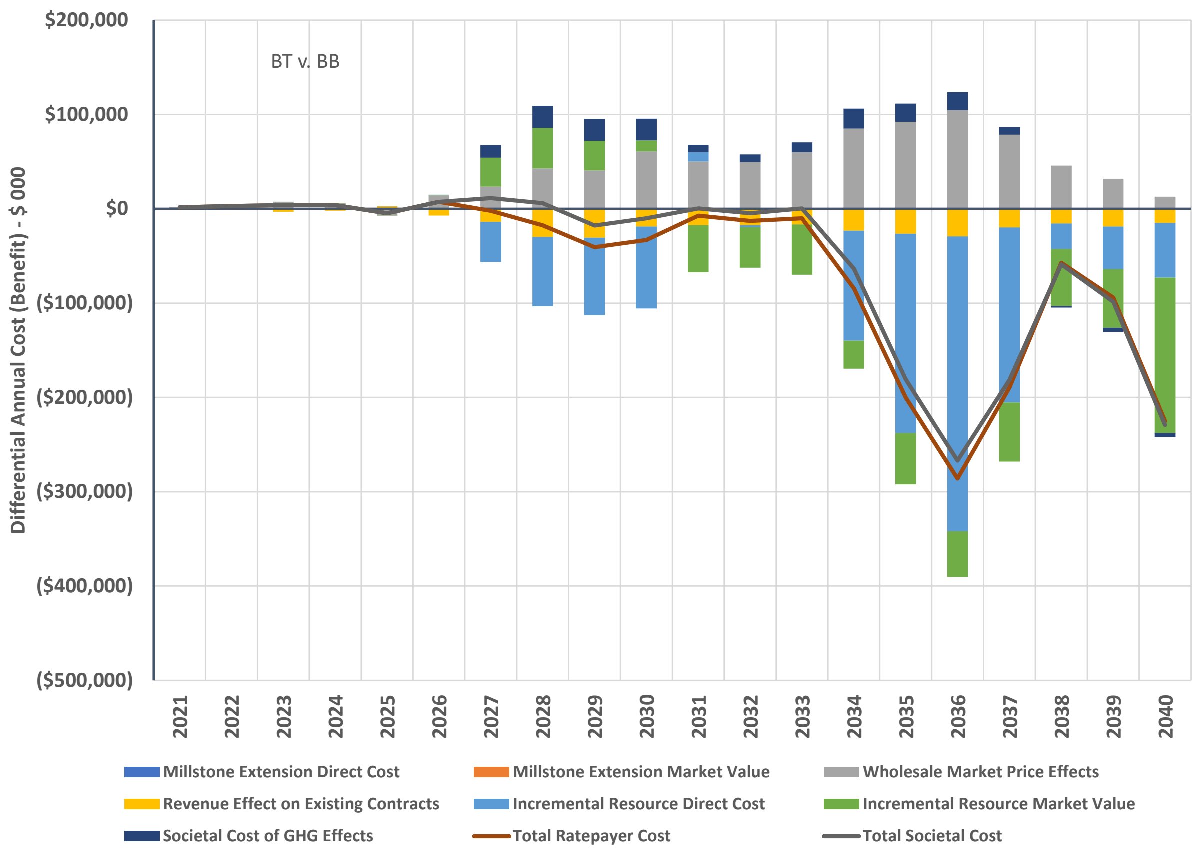
Base Load Case

Annual differential costs for the Base Transmission Scenario are shown in Figure 17. The annual differential costs are negligible through 2027. By 2028, they are increasingly negative through 2036, signifying the realization of lower cost zero carbon resources coupled with reduced curtailments of zero carbon resources in New England when transmission congestion dissipates or is eliminated. The downward sloping brown line through 2040 represents the anticipated year over year benefits that may be realized. The negative cost is driven by the light blue bars, signifying the avoided direct costs of the

[17] The direct costs of the transmission required to mitigate curtailment are not included in the financial model. Hence, the financial results do not signify the cost of implementing a transmission solution to accommodate large new zero carbon injections in Northern New England.

incremental resources otherwise required to meet Connecticut's carbon reduction goals when transmission constraints are included in the electric topology of the region. When the elimination of transmission constraints is tested, Connecticut, and other New England states, would be able to avoid internal interface related curtailments and cultivate fewer zero carbon resources, thereby conferring large economic benefits. Offsetting the negative costs, to a limited extent, are the foregone revenues from the avoided incremental resources and market price effects for energy and capacity. From the inflection point in 2028, there are substantial and sustainable ratepayer benefits ascribable to the absence of congestion.[18]

Figure 17. Differential Annual Cost - Transmission Case (Base Load Case)

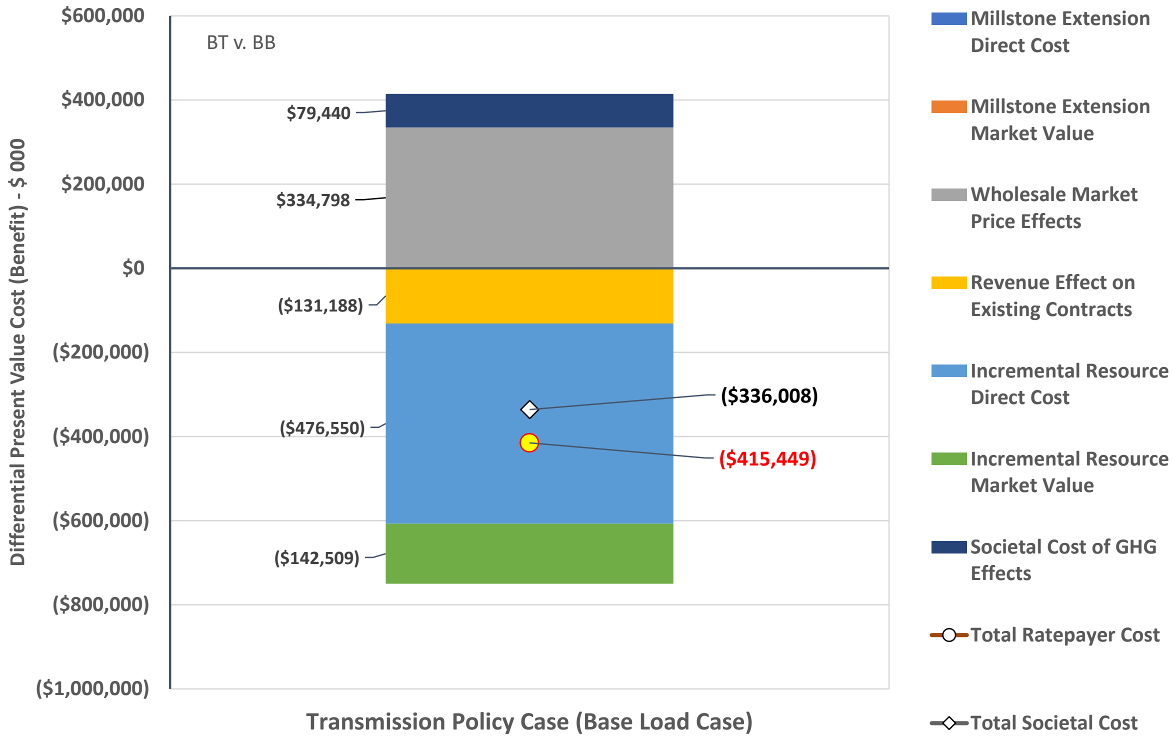


The differential present value costs for the Base Transmission Scenario are shown in Figure 18. The ratepayer financial benefits amount to $0.4 billion present value relative to the Base Balanced Blend Scenario. This is driven primarily by about $0.5 billion in incremental resource direct cost savings, in other words, the displacement of more expensive resources when transmission congestion persists. Wholesale market price effects amount to $0.3 billion present value, reflecting the lost wholesale price benefits

[18] Whether investment in new transmission resources to either mitigate or eliminate congestion is indeed beneficial from a Connecticut ratepayer standpoint will require (1) proposing discrete increases to interface limits, (2) identifying new facilities and upgrades needed to increase interface limits, and (3) estimating facility costs. Moreover, the elimination or alleviation of congestion across RSP zones would require other New England states to support the initiative, including resolution of cost allocation concerns.

associated with the various technologies in the Balanced Blend. The market value of the incremental resource value is $0.1 billion present value.

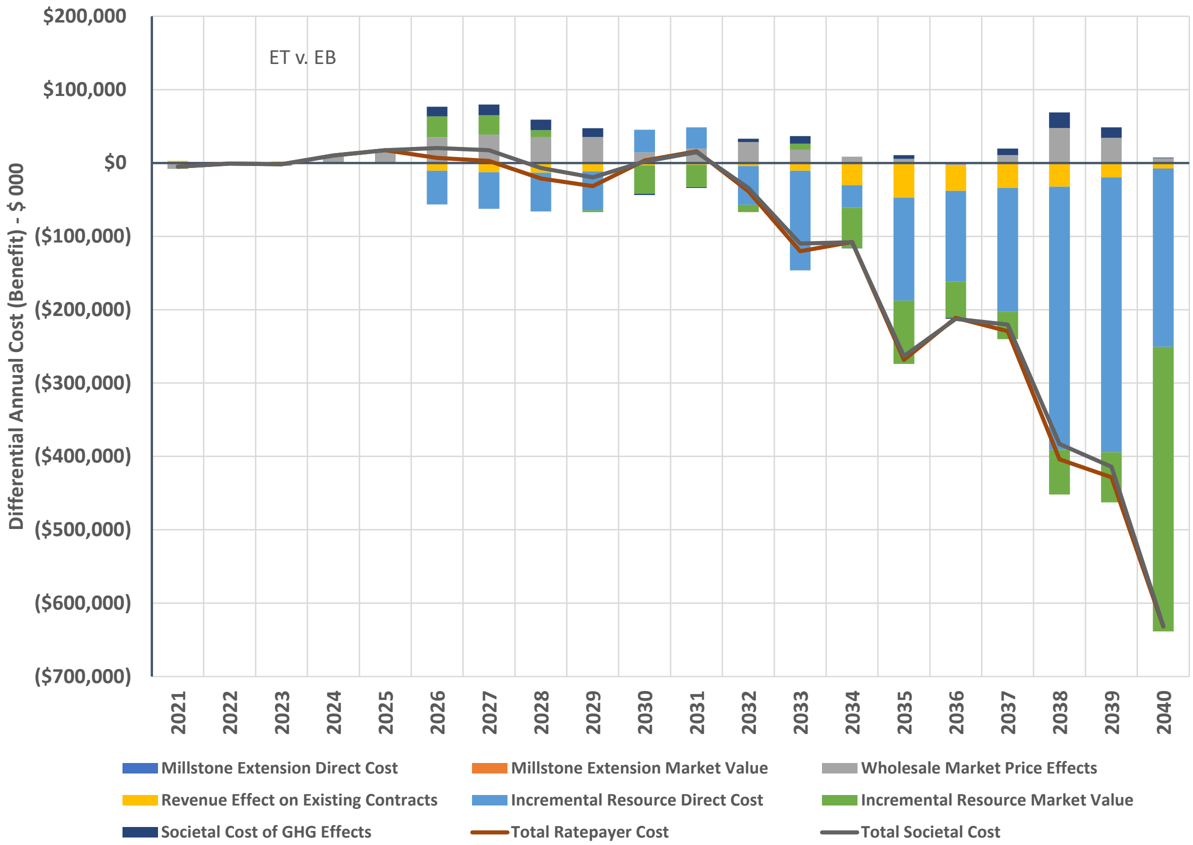
Figure 18. Differential PV Costs - Transmission Case (Base Load Case)



Electrification Load Case

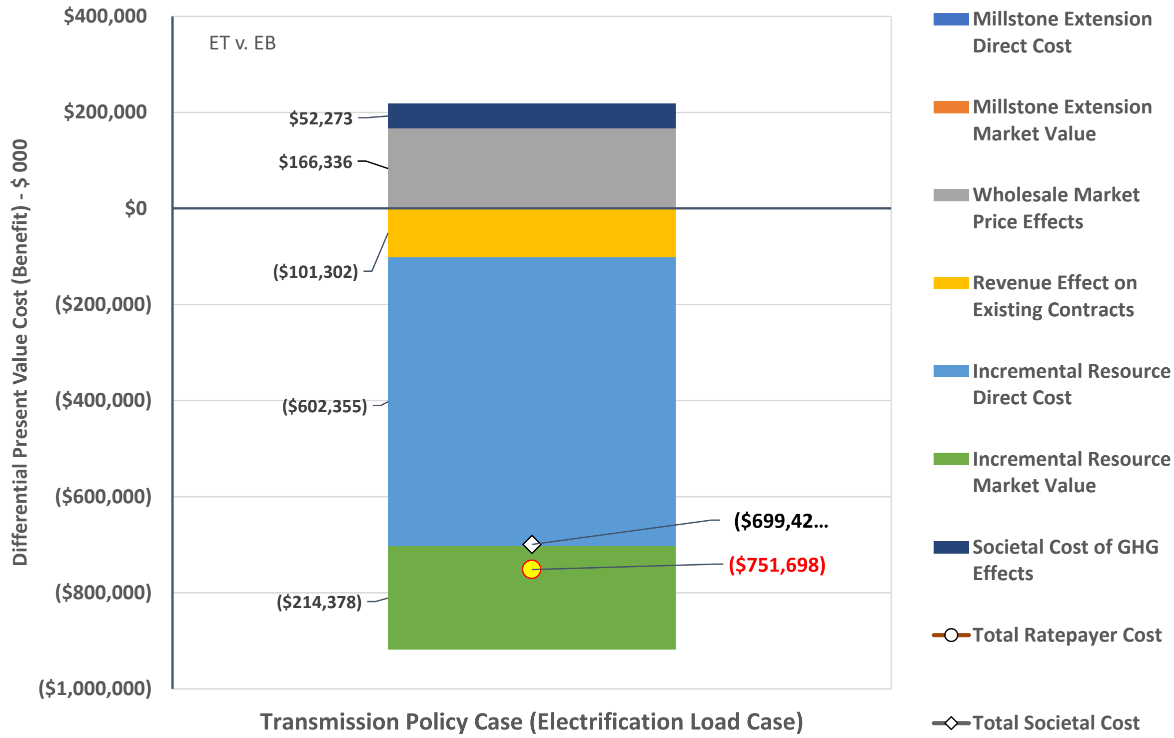
Under the Electrification Load Case, the Electrification Transmission Scenario shows small changes in net cost through 2030, followed by increasing net benefits in the later years in Figure 19.

Figure 19. Differential Annual Costs - Transmission Case (Electrification Load Case)



The differential present value costs for the Electrification Transmission Scenario are shown in in Figure 20. The financial benefits amount to present value $0.8 billion relative to the Electrification Balanced Blend Scenario. This is driven primarily by about $0.6 billion in Incremental Resource Direct Cost reductions, in other words, the displacement of more expensive resources when transmission congestion persists. The market value of the incremental resource revenue has a present value $0.2 billion.

Figure 20. Differential PV Costs - Transmission Case (Electrification Load Case)



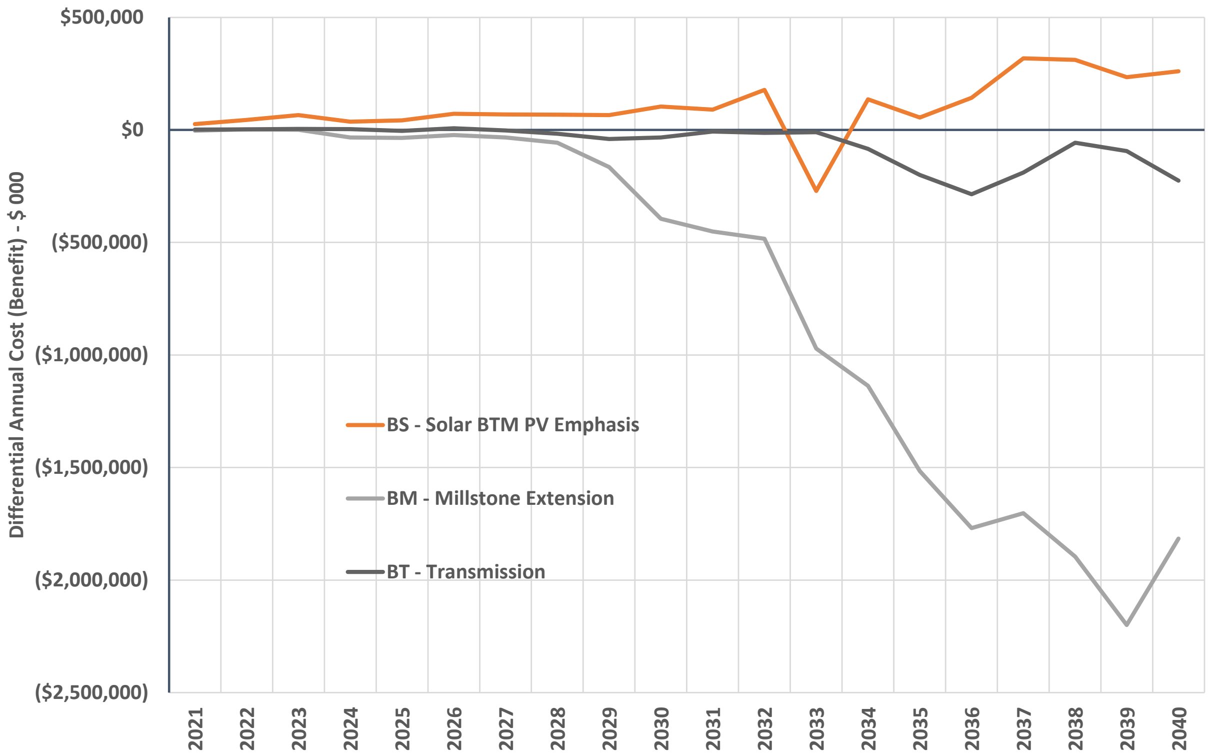
Comparison of Policy Resource Cases

This section compares the three Policy Resource cases (as measured against the Balanced Blend case) under each load case.

Base Load Scenario

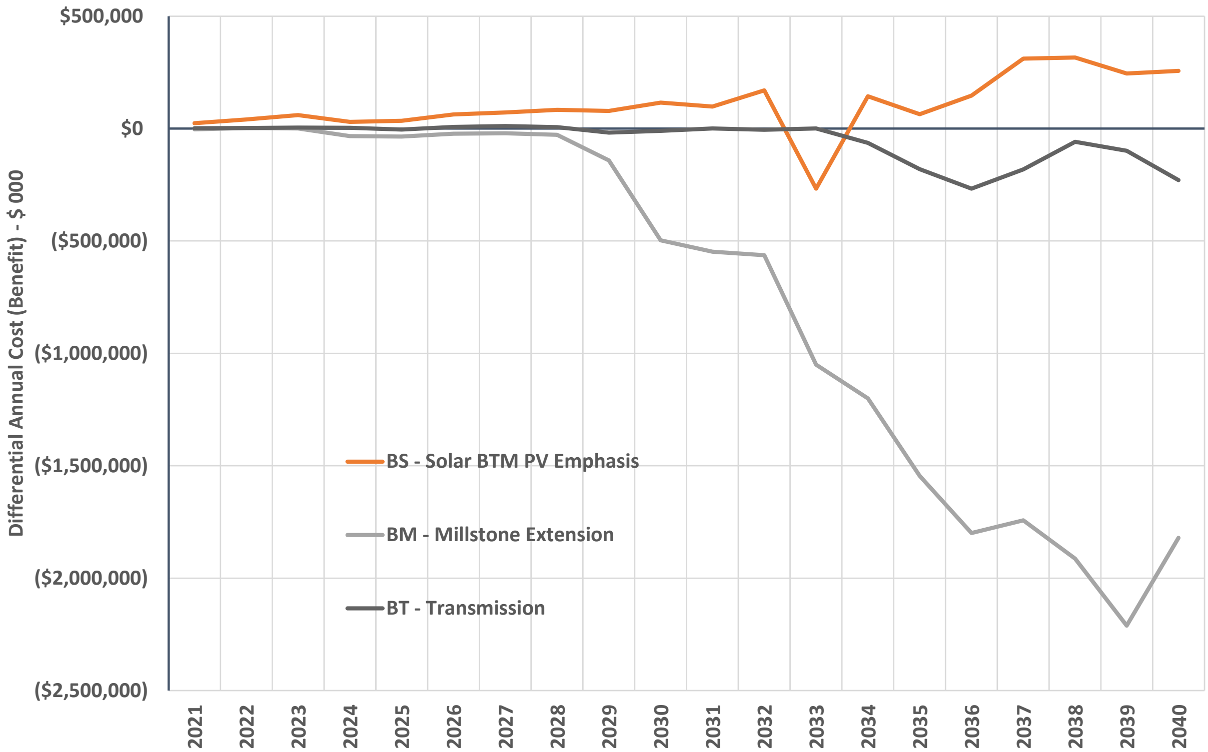
Annual Net Ratepayer Cost lines represent the timing of long-term electric rate effects from the different policy cases. It should be noted that these lines do not include all relevant underlying costs of reaching Governor Lamont's carbon reduction goals embedded in the Balanced Blend and the other resource cases, as discussed above. Figure 21 shows these differential annual ratepayer costs lines on a common scale for ease of comparison. Above the x-axis, the Solar BTM PV Emphasis case represents a significant increase in costs in all years relative to the baseline Balanced Blend case and the other two policy cases. By contrast, the Millstone Extension case provides substantial cost reductions after 2028. The Transmission case also provides significant benefits in the later years, but these may be offset by the lack of specificity regarding to high cost transmission improvements and timing uncertainty to alleviate congestion.

Figure 21. Annual Ratepayer Cost Comparison - Base Load Case



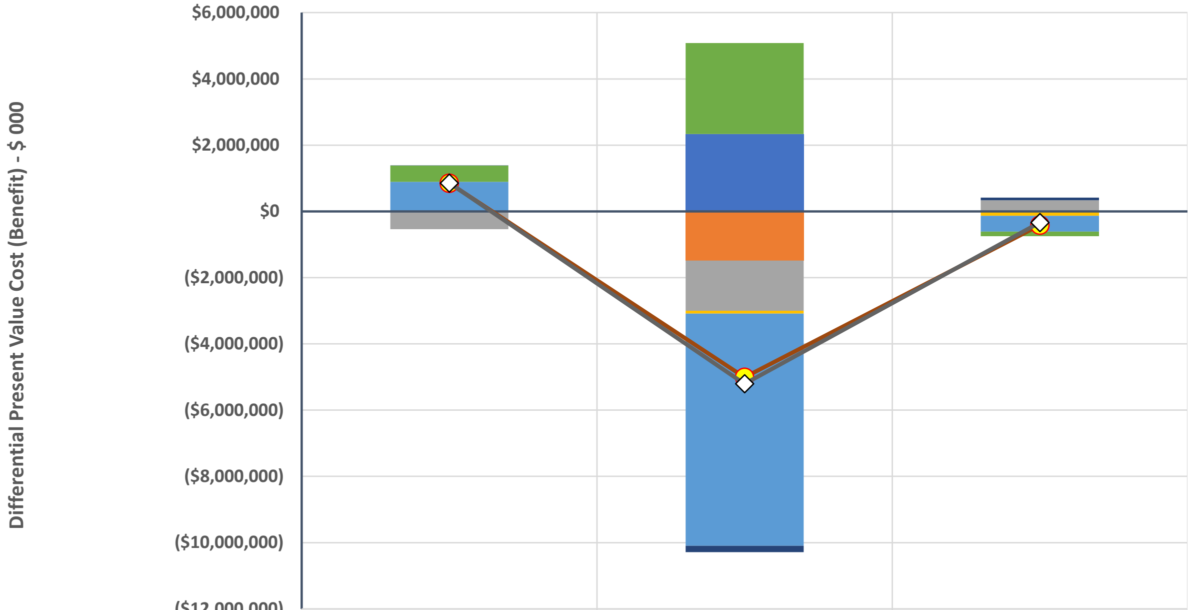
Since all of the resource cases come close to matching the target emission inventory levels in the later years, the annual GHG inventory societal cost adjustments are relatively small. The Net Societal Cost is essentially the same as the Net Ratepayer Cost in most years. This dynamic is presented in Figure 22 relative to Figure 21.

Figure 22. Annual Societal Cost Comparison - Base Load Case



Present values of cost categories relative to the Base Balanced Blend Scenario are shown in Figure 23. The common major component for the three policy resource cases is the light blue bars representing the direct cost to ratepayers of resources added over time to meet annual CO_2 emission reduction goals. The cost is positive for the Base Solar BTM PV Emphasis Scenario which focuses on high cost resources that provide smaller offsetting revenue streams than the utility-scale options available to the Aurora model for selection. Cost is negative for the Base Transmission Scenario, since resources are postponed or replaced with ones of lower cost. The very large incremental resource direct cost for the Base Millstone Extension Scenario is offset by the dark blue bar above the x-axis representing the direct costs of a PPA.

Figure 23. Present Value Cost Comparison - Base Load Case Scenarios

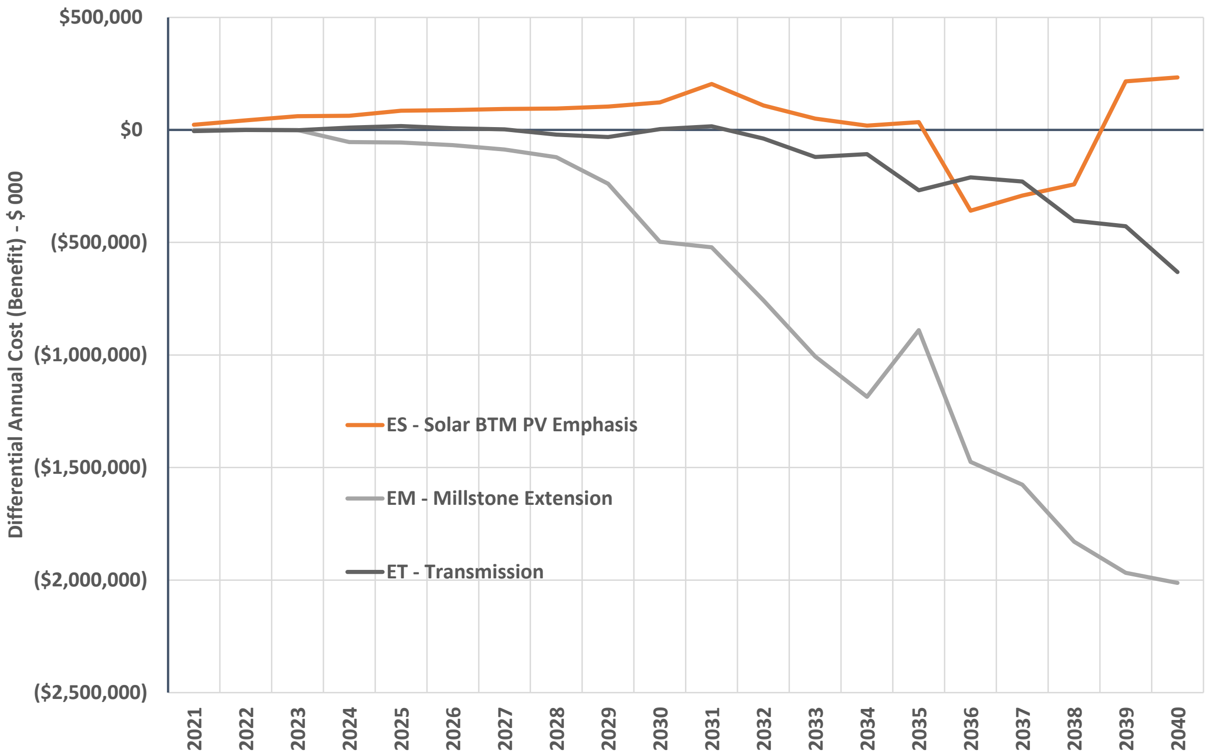


	BS - Solar BTM PV Emphasis	BM - Millstone Extension	BT - Transmission
Societal Cost of GHG Effects	$7,835	($194,809)	$79,440
Incremental Resource Market Value	$492,081	$2,747,502	($142,509)
Incremental Resource Direct Cost	$873,303	($7,009,792)	($476,550)
Revenue Effect on Existing Contracts	$16,969	($86,462)	($131,188)
Wholesale Market Price Effects	($534,591)	($1,510,727)	$334,798
Millstone Extension Market Value	$0	($1,485,509)	$0
Millstone Extension Direct Cost	$0	$2,334,284	$0
Net Ratepayer Cost	$847,762	($5,010,705)	($415,449)
Net Societal Cost	$855,597	($5,205,514)	($336,008)

Electrification Load Case

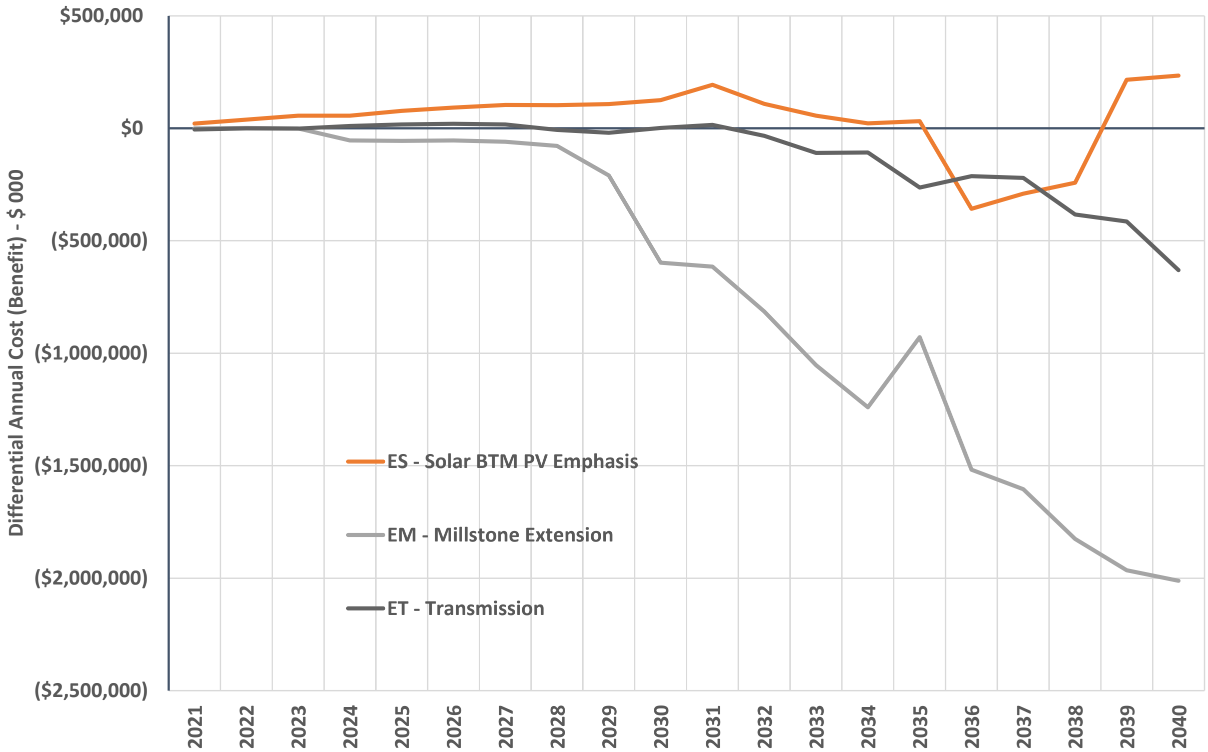
Annual Net Ratepayer Cost lines represent the timing of long-term electric rate effects from the different policy cases. Significant costs have been excluded or counted only in part, however. Hence, all of the relevant underlying costs of achieving Governor Lamont's carbon reduction goals embedded in the Electrification Balanced Blend Scenario and the other resource scenarios have not been presented. Figure 24 shows these differential annual ratepayer costs lines on a common scale for easy comparison. Above the x-axis, the Electrification BTM Emphasis Scenario represents a significant increase in costs in early years, relative to the baseline Electrification Balanced Blend Scenario and the other two policy cases. At the other extreme, the Electrification Millstone Extension Scenario provides substantial cost reductions after 2028. The Electrification Transmission Scenario also provides significant benefits in the later years, but these may be offset by the lack of specific high cost transmission improvements and timing uncertainty to alleviate congestion.

Figure 24. Annual Ratepayer Cost Comparison - Electrification Load Case



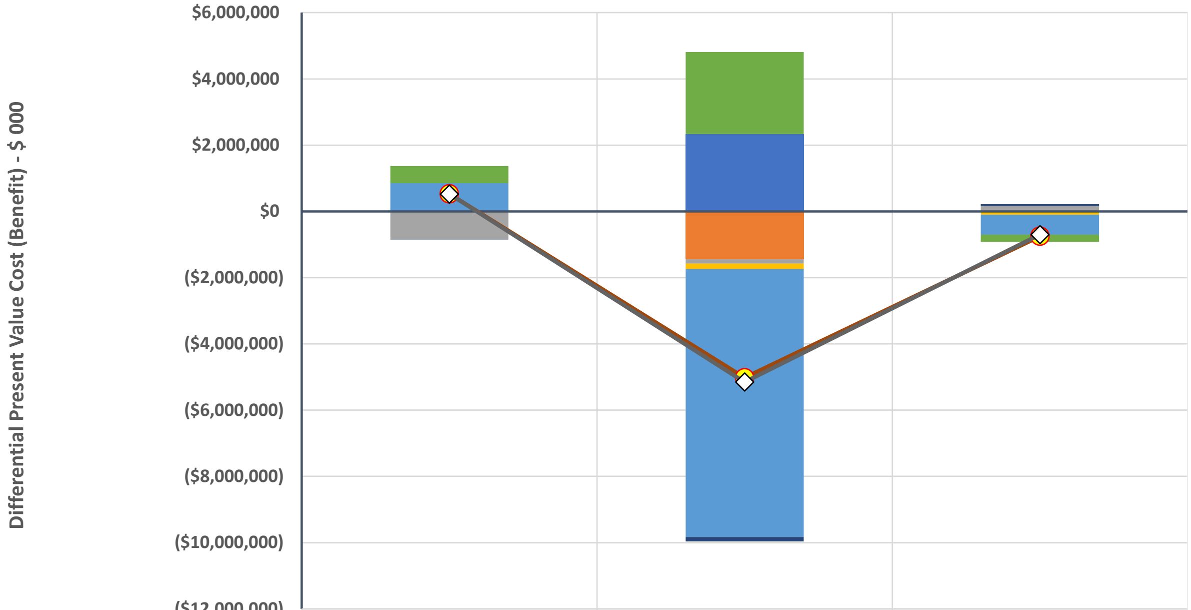
Since all of the resource cases come close to matching the target emission inventory levels in the later years, the annual GHG inventory societal cost adjustments are relatively small. The Net Societal Cost is essentially the same as the Net Ratepayer Cost in most years. This dynamic is presented in Figure 25 relative to Figure 24.

Figure 25. Annual Societal Cost Comparison - Electrification Load Case



Present value costs for the three policy resource scenarios, relative to the Balanced Blend scenario for the Electrification Load Case, are shown in Figure 26. The relationships between the scenarios are generally similar to those shown for the Base Load Case in Figure 23. However, at the component level, there are differences.

Figure 26. Present Value Cost Comparison - Electrification Load Case Scenarios



	ES - Solar BTM PV Emphasis	EM - Millstone Extension	ET - Transmission
Societal Cost of GHG Effects	($4,965)	($129,163)	$52,273
Incremental Resource Market Value	$513,969	$2,473,975	($214,378)
Incremental Resource Direct Cost	$853,664	($8,091,736)	($602,355)
Revenue Effect on Existing Contracts	$770	($160,605)	($101,302)
Wholesale Market Price Effects	($839,782)	($136,409)	$166,336
Millstone Extension Market Value	$0	($1,441,678)	$0
Millstone Extension Direct Cost	$0	$2,334,284	$0
Net Ratepayer Cost	$528,621	($5,022,169)	($751,698)
Net Societal Cost	$523,655	($5,151,332)	($699,425)