Evaluation of Rhode Island Distributed Generation Policies

Stakeholder Workshop #4: Proposed Benefit-Cost Analysis Categories, Assumptions and Inputs

April 7, 2023

Sustainable Energy Advantage, LLC, on Behalf of the Rhode Island Office of Energy Resources

Sustainable Energy Advantage, LLC

Part I: Proposed Methodology, Inputs and Assumptions for Calculating Incremental DG Capacity Target

Calculating Rhode Island's Potential Renewable DG Capacity Gap

- Total Compliance Demand Associated with Meeting 100% Renewable Energy Standard (RES) by 2033 RES, ***LESS***:
  - Baseline DG Programmatic Energy Supply (Operating and Expected to Reach Commercial Operation), including:
    - Baseline On-Site Net Metering (NEM) Production (MWh) (assuming RECs are retired in RI)
    - Baseline Virtual Net Metering (VNM) Production (MWh) (assuming RECs are retired in RI)
    - Baseline Renewable Energy Growth (REG) and DG Standard Contracts Production (MWh)
  - Baseline Large Scale Renewable (LSR) Projects (Operating and Expected to Reach Commercial Operation
    - Large-Scale Renewables Capacity (With Existing Long-Term Contracts)
    - Offshore Wind Capacity with Existing Long-Term Contracts (Revolution Wind & Block Island Wind, 430 MW)
    - Additional Offshore Wind Capacity (884 MW)
  - RI's demand-weighted share of regional RECs eligible across all markets
    - **For background purposes: most recent RES compliance report (calendar year 2020) indicates regional RECs (i.e. out-of-state renewable energy projects) met 54% of 2020 compliance demand**

Determining Total Capacity Subject to Benefit-Cost Analysis

- In general, projects subject to this benefit-cost analysis include
  - Projects that have already qualified and are already in the development, interconnection and/or construction pipeline, but are not yet operational
  - Projects yet to close financing or be developed
- For the purposes of this analysis, SEA assumes that any new distributed generation (DG) legislation (including, but not limited to, the provisions currently in HB 5033/SB 506 and HB 5383/SB 684) before the General Assembly would have some degree of impact on
  - ***Renewable Energy Growth (REG) Program:*** All projects selected in the 2024 program year and thereafter (except for the 300 MW/year expansion which would take effect in the 2025 program year)
  - ***Virtual Net Metering (VNM):*** All projects yet to be developed/qualified (likely based on a cutoff date for executed interconnection agreements)
  - ***Net Metering (NM):*** Projects reaching commercial operation in calendar year 2024 and thereafter

Forecasted 2033 RI Policy-Driven Supply: Baseline DG and Large-Scale RE Production

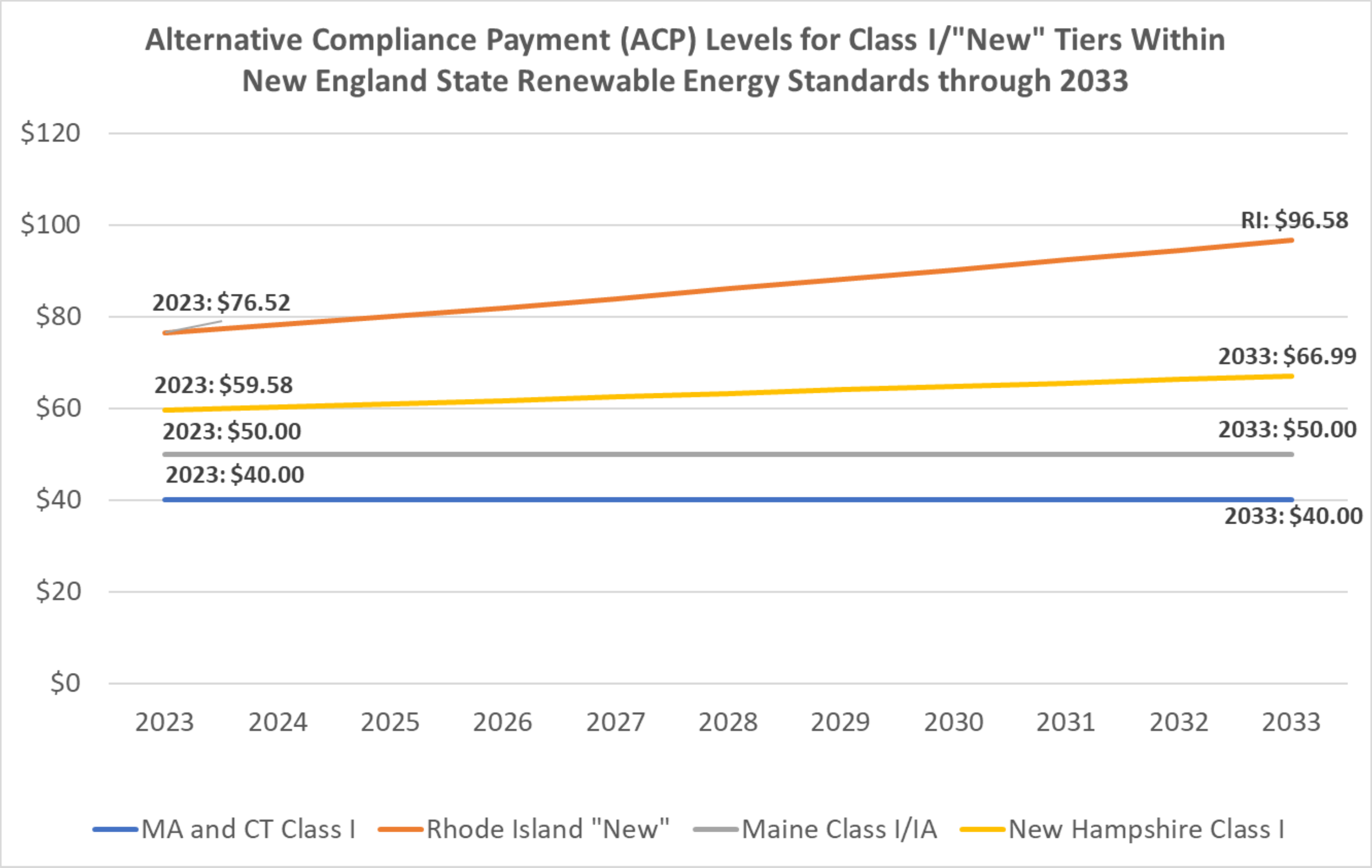
- ***New Offshore Wind (Incremental to Block Island Wind):*** SEA forecasts that RECs associated with Revolution Wind and an additional 884 MW of offshore wind (if reaching commercial operation as currently expected in 2025 and 2030, respectively) represent the equivalent of **51% of total RES compliance demand in 2033** (the first year of the 100% requirement)
- ***Currently Operating "New" Renewable Energy Projects:*** SEA forecasts that RECs associated with currently-operating renewable energy projects (including both DG and large-scale) represent the equivalent of **9% of total RES compliance demand in 2033**
- ***REG/Distributed Generation Standard Contracts (DGSC) Projects:*** SEA forecasts that REC associated with incremental REG and DGSC production will contribute a represent the equivalent of of **4% GWh toward RES compliance in 2033**
- ***NM:*** SEA forecasts that RECs associated with incremental NM projects <u>beyond current operating projects</u> would, if retired in Rhode Island, represent the equivalent of **2% of total RES compliance demand in 2033**
- ***VNM:*** SEA forecasts that RECs associated with VNM projects would, if retired in Rhode Island, represent the equivalent of **2% of total RES compliance demand in 2033**

Contextualizing SEA's Evaluation of Rhode Island's Renewable Distributed Generation Programs

- The New England regional REC market is made up of a series of state renewable energy markets interconnected by overlapping eligibilities between the six states (as well as some adjoining regions)
- This market creates the context in which renewable energy certificates (RECs) are traded – including RECs minted from renewable energy projects across the region and sold to load-serving entities, both in RI and regionally
- SEA has, since 2006, analyzed these interconnected regional markets and their supply/demand dynamics through its New England Renewable Energy Market Outlook (NE-REMO) service
- Though the scope of the instant process to evaluate the state's DG programs is to determine the means by which DG programs may be expanded in the state of Rhode Island via new and/or revised statutes and policies, **we do not intend our work to be interpreted as suggesting that there are not other viable means through which eligible renewable energy resources delivered to the ISO-NE control area can be utilized to meet statutory clean energy and climate targets and objectives (including the 100% by 2033 Renewable Energy Standard)**

Assessing Potential Contribution From Regional RECs

- In general, sellers of regional RECs tend to seek out the market with the highest Alternative Compliance Payment (ACP), since such markets tend to have the highest REC prices
    - While MA and CT have set a flat $40/REC ACP, RI has a higher ACP that is tied to inflation
    - If the ACP schedule is not changed, SEA estimates this ACP will be **$97/REC** in 2033 (and continuing to rise thereafter)



Assessing Potential Contribution From Regional RECs

- Under its New England REMO Base Case assumption, **there is sufficient regional REC supply that could be sold to RI load-serving entities (LSEs) in the absence of future in-state policy-driven supply to fill the gap** (the majority of which consists of several very large OSW projects contracted to other states)
- However, if Rhode Island wishes to fill the gap between compliance demand and existing policy and not rely on regional REC supplies to do so, the difference would be equivalent to **2,057-2,742 MW of incremental DG through 2033** (representing 15%-20% CF range)
- Ultimately, the degree of retirement of RECs to meet RES policy targets (whether minted from in-state or out-of-state projects) will be driven by the differentials between various state ACP dollar values per MWh

Target DG Capacity for Benefit-Cost Analysis

- To meet a portion of this gap with in-state renewable energy projects, SEA will model the following for the analysis of the benefits and costs of the following resources, to be developed and constructed between 2024 and 2033:
  - An incremental **1,560 MW (at least)** of Renewable Energy Growth (REG) program capacity (equivalent to the incremental capacity contemplated in HB 5853/SB 684, each year from the 2024 through 2029 Program Years)
    - **NOTE:** Although the Sub A version of SB 684 includes four additional years of 300 MW/year beyond what is contemplated above, the modeling in this analysis is keyed to the gap in 2033. Therefore, **the final amount of incremental capacity will be based on the amount of projects qualified/procured between 2030-2033 that can reach commercial operation by the end of 2033**
  - An additional **500 MW** of virtual net metering capacity
  - An additional **239 MW** of on-site net metering capacity (representing the additional on-site net metering capacity expected to be developed in line with existing statute)
    - This value represents a continuation of recent trends in project completions
- The remainder is functionally assumed to be met by regional RECs (which may include new large-scale renewable resources, including offshore wind projects, in other states)

Further Assumptions Regarding Incremental Capacity

- All incremental capacity modeled will be expected to reach commercial operation no later the end of 2033 (the end of the first year in which the 100% RES will be enforced)
- On-site net metering and virtual net metering capacity assumed to be solar PV
- <u>Strictly for modeling simplification purposes</u>, all modeled REG capacity will be assumed to be solar PV resources

Part II: Proposed Methodology, Inputs and Assumptions for DG Project Economic Analysis

Highlights of Proposed PV Cost/Performance Assumptions (1)

- Installed cost estimates (based on regional solar projects) were set based on:
  - **For 1 MW_{AC} Projects: Averages of median and 25th percentile values** from state databases in the Northeast region and actual as-bid values for projects submitting bids in 2022 Rhode Island Renewable Energy Growth (REG) Open Enrollments
  - **For 5 MW_{AC} Projects:** An **average of the average and median value** of several different Northeast regional statewide databases
- Installed costs (excluding interconnection) assumed to decline in all cases through 2033 based on an average of the NREL Annual Technology Baseline (ATB) 2022 Moderate and Conservative cases **(~3%/yr)**
- Project performance based on **assumed location in Providence, RI** (near the latitudinal center of the state), **as adjusted by regional real-world observed project performance**

Highlights of Proposed PV Cost/Performance Assumptions (2)

- Interconnection costs for greenfield projects >1 MW assumed to rise **from current observed levels, up to the average DG customer-assessed costs observed in Massachusetts Capital Investment Project (CIP) provisional program** in time for projects **closing financing in 2027**, and rise at forecasted **AEO 2023 chain-type CPI rates** thereafter
- Interconnection costs for non-greenfield >1 MW projects that are typically closer to load assumed to rise at **one-half the rate of greenfield projects >1 MW**, and rise at forecasted AEO 2023 chain-type CPI rates thereafter
- Interconnection costs for projects >25 kW to 1 MW assumed to rise **at forecasted AEO 2023 chain-type CPI rates**

Highlights of Proposed PV Cost/Performance Assumptions (3)

- All projects greater than 1 MW assumed to include added cost of meeting Inflation Reduction Act (IRA) prevailing wage requirements (**starting at $57.50/kW$_{DC}$**)
- Prevailing wage values assumed to rise **at EIA Annual Energy Outlook 2023 Chain-Type CPI rate thereafter**
- Annual degradation assumed at **1% for <= 25 kW$_{AC}$** projects, **0.8% for 25 kW to 1 MW$_{AC}$** projects, and **0.5% for >= 5 MW$_{AC}$** projects

Highlights of Proposed PV Cost/Performance Assumptions (4)

- Specific proposed cost and performance inputs, by size bin, are provided below
- These "base" inputs may be transformed or added to based on specific project characteristics (e.g., siting, offtakers), as described on the next slide

Solar Classes	Small Solar I	Small Solar II	Medium Solar	Commercial Solar I	Commercial Solar II	Large Solar I	Large Solar II	Large Solar III
Nameplate Capacity (kW_{DC})	7	25	250	500	1,000	5,000	10,000	20,000
Capacity Factor	13.4%	13.4%	14.5%	14.6%	14.6%	15.10%	15.10%	15.10%
Annual Degradation	1.0%	1.0%	0.8%	0.8%	0.8%	0.8%	0.5%	0.5%
*Useful Life (Years)^*	25	25	25	25	25	30	30	30
Total Capital Cost ($/kW)	$3,566	$3,058	$2,485	$2,352	$2,218	$1,964	$1,381	$1,148
Prevailing Wage ($/kW)	N/A	N/A	N/A	N/A	N/A	$57.5	$57.5	$57.5
Fixed O&M ($/kW-yr)	$29	$24	$14.57	$12.03	$12.03	$11.00	$9.00	$9.00
O&M Escalation Factor	2.0%	2.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%
Non-O&M Escalation %	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
Insurance (% of Cost)	0.0%	0.0%	0.34%	0.57%	0.57%	0.57%	0.57%	0.57%
Project Management ($/yr)	$0	$0	$3,000	$4,000	$4,000	$20,000	$40,000	$80,000
Site Lease ($/yr)	$0	$0	$23,517	$31,850	$42,195	$122,889	$245,778	$491,556

^Note: Non-Large projects assumed to be sited on rooftops, and thus have 25 year useful lives, relative to 30-year useful lives of Large projects

Highlights of Proposed PV Cost/Performance Assumptions (5)

- Base inputs are altered based on specific project characteristics, as follows

Component	Adjustment	Offtaker-based Adjustors (Premium to Greenfield Ground-Mounted Project with No Offtakers)		Siting-based Adjustors (Premium to Greenfield Ground-Mounted Proxy Project)					
		Shared Solar	Low & Moderate Income (LMI) Shared Solar	C&I-Zoned	Rooftop	Brown-field	Landfill	Gravel Pit	Carport
Capacity Factor	*Relative % change*	N/A	N/A	N/A	**-10%**	N/A	**-5%**	**-2%**	**-12%**
Total Capital Cost ($/kW)	*Incremental Installed Capital Cost*	**+50/kW**	**+100/kW**	N/A	N/A	+$330/kW	**+$350/kW** (+$100k permitting premium)	**+$100/kW** (+$30k permitting premium)	**+$840/kW**
Fixed O&M ($/kW-yr)	*Varies*	**+$22/kW-yr**	**+$28/kW-yr**	N/A	**+15%**	**+16%**	**+15%**	N/A	**+20%**
Insurance (% of Cost)	*Relative % change*	N/A	N/A	N/A	**+10%**	**+15%**	**+10%**	N/A	**+5%**
Project Management ($/yr)	*Relative % change*	N/A	N/A	N/A	N/A	**+7%**	**+10%**	**+5%**	N/A
Site Lease ($/yr)	*Relative % change*	N/A	N/A	+106%	**+23%**	**+2%**	N/A	**+10%**	N/A

Highlights of Proposed Financing/Tax Assumptions (1)

- All projects assumed to be owned by either:
  - Third party (taxable) corporate entities (hereafter referred to as third-party owned or TPO)
  - Customer hosts (hereafter referred to as "Host");
- TPO and Host owners thus assumed to pay state and federal corporate tax (given vast majority of DG projects at this scale are not host customer-owned)
- **Projects included in supply blocks assumed eligible under federal tax code provisions** related to the Investment Tax Credit (ITC) for projects that either <u>begin construction</u> prior to 12/31/2024, as well as the availability of the successor Clean Energy Investment Credit (CEIC) for projects that are <u>placed in service</u> no earlier than January 1, 2025 (therefore rendering "safe harboring" irrelevant to this analysis)

Highlights of Financing/Tax Assumptions (2)

- The two tax credits have **functionally identical statutory provisions**, including:
  - A full tax credit value of 30%
  - Bonus credits ranging from 10% (for projects sited on brownfields or other “energy communities” or in “low income or disadvantaged communities”) to 20% (for projects serving low-income offtakers)
  - The ability to include the cost of transmission and/or distribution system modifications in the project’s basis for calculating the value of either type of investment credit
  - The ability to transfer tax credits
- Given increasing project delays (which make it impossible to claim bonus depreciation under existing Tax Cuts and Jobs Act of 2017 provisions phasing out bonus depreciation for projects placed in service no later than the end of 2026) **we assume projects can only monetize 5-year MACRS depreciation (and cannot monetize bonus depreciation)**

Highlights of Financing/Tax Assumptions (4)

- Debt shares held constant over analysis term, and sized to meet an average debt service coverage ratio (DSCR) of 1.25
- Debt terms vary based on the degree of hedged revenue (ranging from 10-13 years for status quo policy cases, to 13-15 years for policy cases with a higher degree of attribute transfer)
- Interest rates to be calculated based on 10- and 20-year Treasury note values **on April 1, 2023**, plus a risk premium of 325 basis points (resulting in interest rates that are +10 bps higher in policy cases assuming more hedged revenue)
- Tax equity investors continue to be assumed to take the most valuable share of the project's net present value, and thus are assumed to constitute a larger share of the project's capital stack
- Projects with bonus 40% or 50% ITC/CEIC values include larger tax equity shares of total equity than projects eligible for 30% credits
- Post-tariff revenue to be assumed
    - Discounted net metering compensation for REG projects (by statute); and
    - ISO-NE wholesale energy + RECs for net metering and virtual net metering projects
- All applicable Rhode Island tax rates assumed

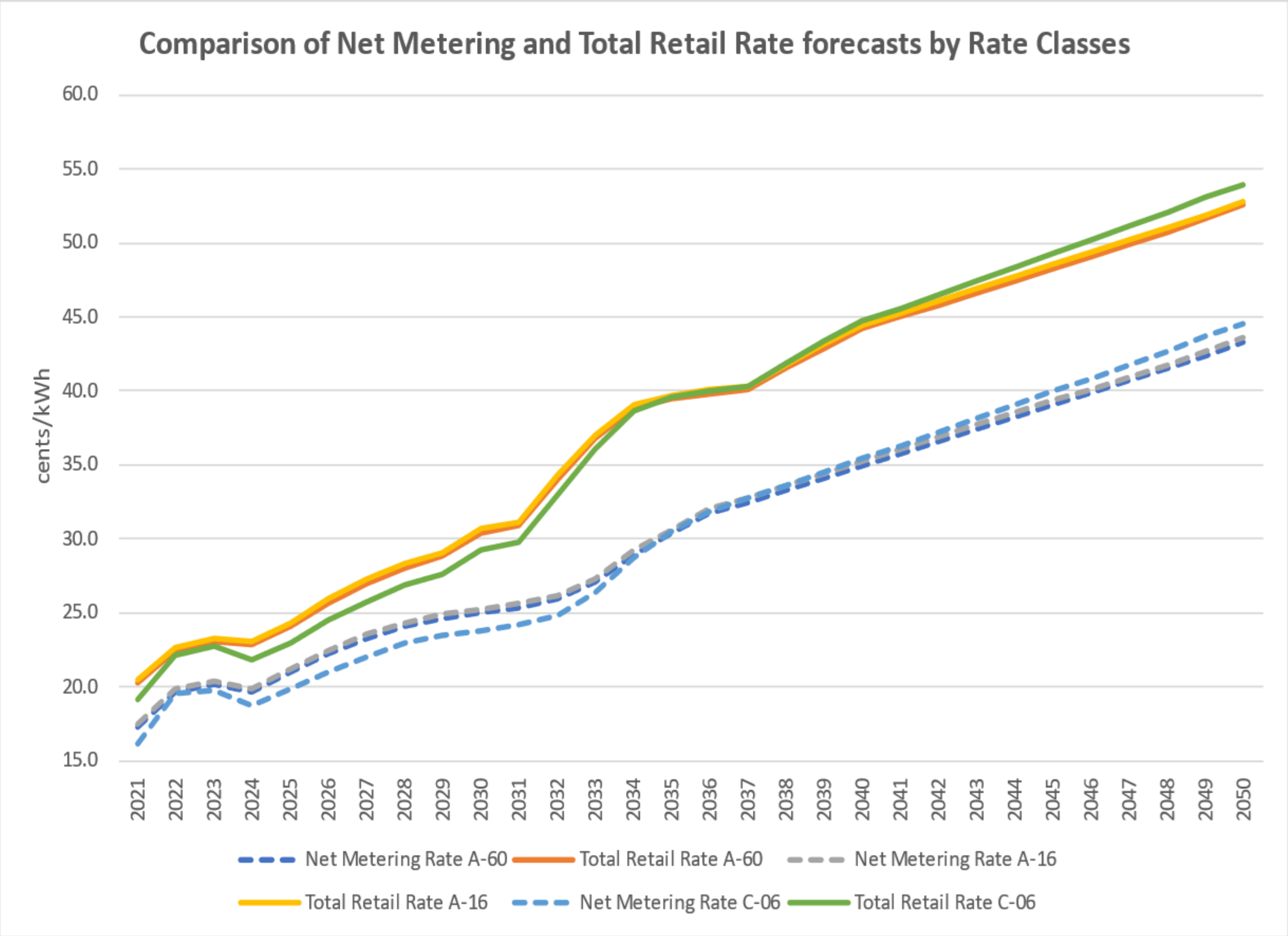
Storage Cost Assumptions

- Storage capital and operating cost inputs are provided in the table below, based on SEA internal research and stakeholder feedback from prior engagements
- All installed capital cost values are for a facility closing finance in 2022, and will be scaled to reflected expected cost declines for future years based on SEA's internal research
- SEA assumes battery replacement at year 15, with a cost of 50% of initial capital expenditure (based on expected cost declines after COD and partial replacement of initial equipment)

	Unit	Medium	Comm'l Solar I	Comm'l Solar II	Large Solar I	Large Solar II	Large Solar III
PV Capacity	kW_{DC}	250	500	1,000	5,000	10,000	20,000
Storage Capacity	kW_{DC}	80	160	325	1,250	2,500	5,000
Duration	Hours	4	4	4	4	4	4
Installed Capital Cost	$/kWh	$832	$832	$832	$534	$495	$469
Operating Expenses	Nominal $/yr	$1,839	$3,678	$7,472	$24,292	$48,584	$97,168

Comparison of Net Metering vs. Retail Rates by Rate Class

- In order to model the economics/viability of certain types of VNM and NM projects under the status quo program design, SEA has forecasted retail rates and NM/VNM credit rate components for the following classes:
  - Residential (A-16)
  - Residential Low-Income (A-60); and
  - Small Commercial (C-06)
- Most significant degree of difference between NM/VNM credit rate and retail rate = RES charge (which is part of the Last Resort Service (LRS) charge)
- SEA plans to only model project blocks under status quo cases that economically clear, assuming receipt of these revenue streams
- **See Appendix B for more details**



Key Sources: Rhode Island Energy 2023 retail rate filings, Sustainable Energy Advantage New England Renewable Energy Market Outlook

Part III: Proposed Methodology, Inputs and Assumptions for Benefit-Cost Analysis

Overall BCA Approach

- Docket 4600 provides framework for conducting benefit cost analysis (BCA), establishing the "Rhode Island Test"
- The Rhode Island Test considers a wide range of costs and benefits, helping stakeholders understand the broad impacts of a given program/policy
- SEA's BCA accounts for most impactful categories of benefits and costs, helping understand overall impact and differences between various program designs and project type
- BCA is *not* the same as rate impact analysis,
- However, our team has identified benefits and costs likely to impact bills and will provide a rough estimate of overall bill impact (an approach similar to what is known as a "Ratepayer Impact Measure" test)

Accounting for Ownership of Capacity + RECs

- As described in SW #3, ownership of energy, capacity and RECs may be retained by project owner, or could also be conveyed to RIE

If the commodity is retained by project owner…

↓

This would reduce their revenue required from other sources, since they can sell the commodity

↓

If compensation is cost-based (e.g., REG), this reduces the remaining compensation paid to resource

↓

Because value of this commodity is accounted for in the DG compensation, not counted as a benefit

If the commodity is conveyed to RIE…

↓

Project would require higher incentive, as it cannot sell the commodity

↓

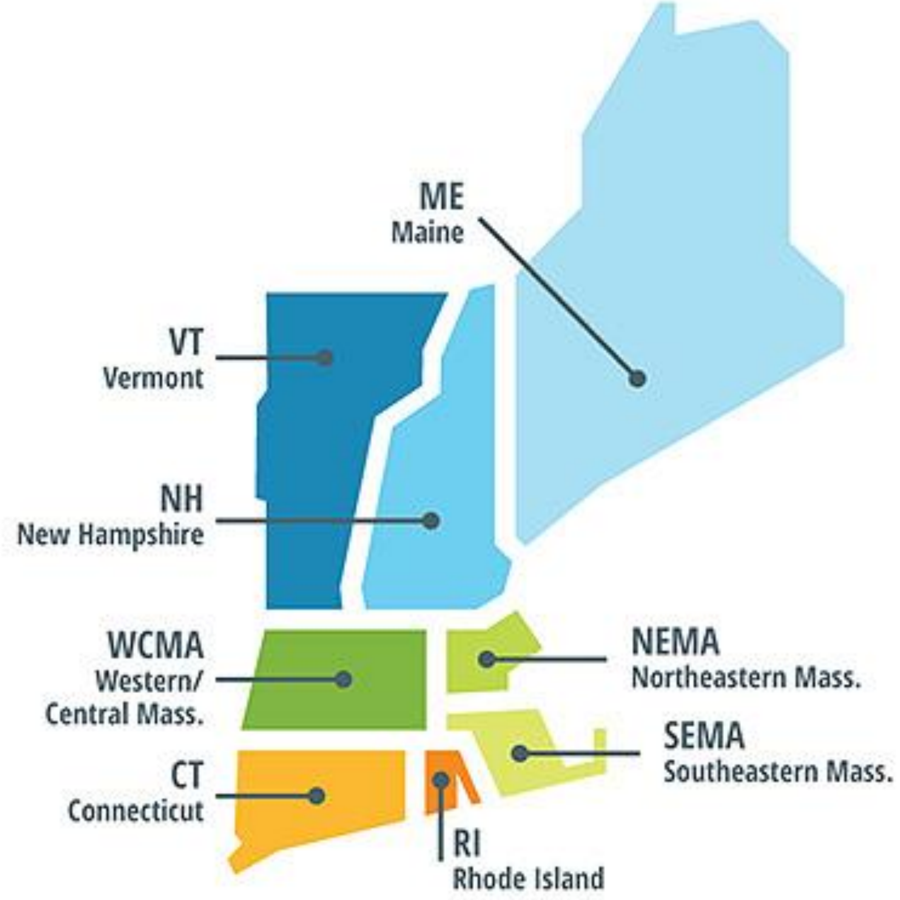
Assume that the RIE sells the commodity at a market price

↓

Since commodity not included in compensation, captured as a benefit

Other Key Concepts

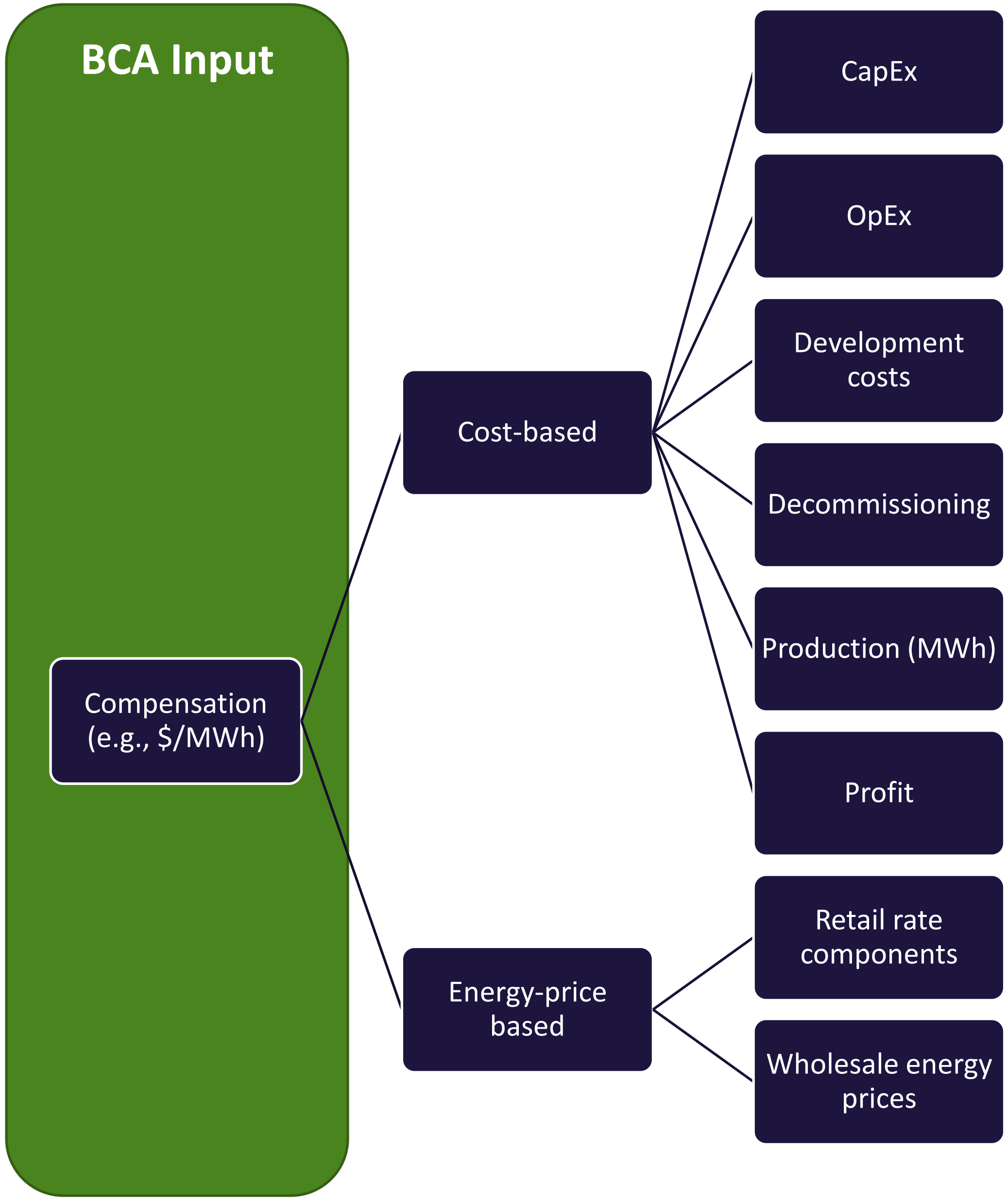
- Cleared vs. uncleared capacity
  - For some values (e.g., capacity price effects), different projected values apply depending on whether a resource had bid into and cleared the capacity market or not
  - In general, this distinction is more likely to be impactful for BTM projects
  - Throughout, we assume projects will be bid into and clear in the capacity market
- Intrastate vs. regional benefits
  - Certain price effect benefits (see later slide) have financial benefits for all ISO-NE customers
  - Possible to calculate benefits specific to RI (intrastate) vs. regional benefits
  - We incorporate the regional benefits



Wholesale Load Zones in New England

Cost – DG Compensation

- “Measure” costs (in this case, costs associated with building/operating DG) can be incorporated into BCA many ways
- Our approach focuses on capturing this cost at the point of *compensation* to the resource, which embeds many upstream factors (which are considered in CREST modeling)
- Compensation varies by resource and case, but generally:
  - Cost-based – assumes compensation tied to revenue requirements (e.g., REG)
  - Energy price-based – tied to retail rate components and/or wholesale energy prices



Cost – Utility Administration and Remuneration

- Utility Administration Cost
  - Administrative expenses for REG are available in annual Renewable Energy Growth Program Factor Filing
  - Estimated costs for Program Year ending 3/31/2023 were $1.18 million
  - SEA will work with RIE to establish estimates for administration costs for other evaluated programs and to understand if any modeled program designs would be likely to have incremental administrative costs
- Utility Remuneration/kWh
  - For REG, will assume remuneration sensitivities of:
    - No remuneration
    - 0.75% remuneration
    - 1.75% remuneration (current law)

Avoided Energy Supply Component (AESC) Overview

- The AESC study is used by the New England states to estimate the benefits of running various programs
  - Initially, specifically for energy efficiency plans, but use has broadened since
  - Overseen by stakeholders including utilities, state energy offices, and advocates
  - Most recent study completed in 2021
- The AESC includes multiple scenarios with differing assumptions related to EE deployment, renewables deployment, etc.
  - Counterfactuals 1-4 (which assume no/limited new energy efficiency) generally used to calculate benefits from energy efficiency
  - Given our consideration of distributed generation, we found the "All-in climate policy" case to be more appropriate – it can be interpreted "as a projection of <u>expected</u> energy prices, capacity prices, and other price series in a future with ambitious climate policies."

Overview of Benefit Categories

Benefit Category	Description of Benefit	Anticipated Source for Value
Avoided Energy Benefits	The valued of energy generated by modeled DG (offsetting the need to purchase energy from other generators in ISO-NE wholesale energy markets)	2021 Avoided Energy Supply Component (AESC), with modifications for near-term gas prices
Energy Price Effects Benefits	The assumed change in the ISO-NE wholesale energy prices resulting additional supply from modeled DG	2021 AESC
Avoided Capacity Benefits	The value of capacity from modeled DG in the ISO-NE Forward Capacity Market (FCM)	2021 AESC
Capacity Price Effects Benefits	The assumed change in the price paid to resources assuming a capacity supply obligation (CSO) in the FCM resulting from the additional capacity bid by modeled DG	2021 AESC
Transmission Benefits	The avoided cost of new transmission assets and facilities resulting from modeled DG	2021 AESC
Distribution Benefits	The avoided cost of new distribution assets and facilities resulting from modeled DG	RIE 2023 Energy Efficiency Plan

See Appendix B for more methodological details

Overview of Benefit Categories

Benefit Category	Description of Benefit	Anticipated Source for Value
Renewable Energy Credit (REC) Benefits	The value of RECs titled to (and resold by) Rhode Island Energy at forecasted commodity REC values	Sustainable Energy Advantage's New England Renewable Energy Market Outlook (REMO)
Non-Embedded Greenhouse Gas (GHG) Reduction Benefits	Value, based on a social cost of carbon methodology, of reduced GHG emissions not already captured in energy prices, adjusted to reduce overlap for benefits captured in REC value	2021 AESC Supplemental Study: Update to Social Cost of Carbon Recommendation
Non-Embedded NO_x Benefits	Value of reduced NO_x emissions not already captured in energy prices	2021 AESC
Reliability Benefits	The benefit to utility customers associated with reduced odds of outages, as well as ability (in the case of energy storage) to serve load during an outage)	2021 AESC
Land Use Benefits	The carbon sequestration and other ecological benefits associated with not siting projects on greenfields	USFS EVALIDator, Delaware Valley Regional Planning Commission study
Macroeconomic Benefits	Economic impacts (e.g., jobs, spending) resulting from construction and operation of modeled DG projects	National Renewable Energy Laboratory's Jobs and Economic Impact (JEDI) model
Low-Moderate Income (LMI) Benefits	Reduced utility costs associated with financial benefits flowing to LMI customers	RIE 2023 Energy Efficiency Plan

Request for Comments

Due Date for Written Comments Related to this Workshop

- Please submit any written comments regarding subjects discussed at this workshop **no later than April 14, 2023 at 11:59 pm Eastern Time (ET)**
- Please send written comments **in a PDF attachment** (preferably on organizational letterhead if applicable) to Cal Brown (cbrown@seadvantage.com), copying me (jkennerly@seadvantage.com) and Karen Bradbury (karen.bradbury@energy.ri.gov)

Appendix A: DG Project Economic Analysis Methodology Details for Reference

Highlights of Financing/Tax Assumptions (3)

Year	*2024*	*2025*	*2026*	*2027*	*2028 and thereafter*
Statutory ITC/ CEIC Value (%)*	• Large Rooftop/Carport/Ground Mount (No Project Offtaker/Siting Bonus from IRA): **30% ITC/CEIC** • Large Carport or Ground Mount (Brownfield/Energy Community or Sited in LI/Disad. Comm.): **40% ITC/CEIC** • Large Ground Mount (LI Benefit Projects): **50% ITC/CEIC**				
Debt %^	• Projects Monetizing 30% ITC/CEIC: **Will start with 47%-52%, but will adjust as needed to meet minimum coverage ratios** • Projects Monetizing 40% ITC/CEIC: **Will start with 40%-44%, but will adjust as needed to meet minimum coverage ratios** • Projects Monetizing 50% ITC/CEIC: **Will start with 34%-36%, but will adjust as needed to meet minimum coverage ratios**				
Debt Tenor^	For All Projects: **10-15 years**				
Interest Rate on Term Debt %†	**TBD (Average of 10- and 20-Year Treasuries on April 1, 2023, plus +325 basis point (bps) Risk Premium)**				
Lender's Fee*	For All Projects: **2%**				
Sponsor/Tax Equity Split*	• Projects Monetizing 30% ITC/CEIC: **25%/75%** • Projects Monetizing 40% ITC/CEIC: **17.5%/82.5%** • Projects Monetizing 50% ITC/CEIC: **10%/90%**				
Sponsor/Tax Equity After-Tax IRRs (Levered)*	• Tax Equity IRR (All Projects): **9.5%** • Sponsor Equity IRR (All Projects): **11%**				
Consolidated After-Tax Equity IRR (Levered)^	• Projects Monetizing 30% ITC/CEIC: **10.03%-13.5% (with lowest values for largest projects under most hedged policy designs)** • Projects Monetizing 40% ITC/CEIC: **-11 bps relative to 30% ITC/CEIC case** • Projects Monetizing 50% ITC/CEIC: -**22 bps relative to 30% ITC/CEIC case**				
Depreciation	For all Projects: **5-Year MACRS (no bonus depreciation)**				

***Value held constant across all years.**
^Value held constant across all years. The lowest end values represent policy cases with low/no hedged attribute revenue expectations, with values increasing as more revenue is hedged. Host owned cases not shown.
†The lowest end values represent policy cases with low/no hedged attribute revenue expectations (and shorter debt terms), with values increasing as more revenue is hedged (and longer debt terms are assumed). The assumed trajectory of interest rates is informed by federal funds rate expectations over the medium- and long-term, which drive pricing of 10- and 20-year Treasury note values.

Methodology for Retail Rate Forecast (1)

- SEA forecasted RI retail rates (for classes A-16, A-60, C-06) based on a subcomponent-level analysis, as follows:
  - **Generation Charge:**
    - SEA constructed a regression predicting LRS charges as a function of historic natural gas forwards at the time of procurement bid dates and capacity prices, taking into account RI's layered procurement schedule
    - The regression performs well, with an adjusted R-Squared of over 80%
    - LRS charges are then forecasted using current natural gas forwards and SEA's internal capacity price forecast
    - The RES charge (a subcomponent of the LRS charge) is modeled by taking the index of annual RES Class I requirements multiplied by SEA's internal Class I REC forecast. The index is applied to the 12-month average charge of the previous year (2022)

Methodology for Retail Rate Forecast (2)

- **Transmission**
  - Through 2027, transmission charges are informed by ISO-NE rate projections
  - Afterward, transmission charges are indexed to the 2023 AEO northeast transmission rate forecast
- **Distribution**
  - We assume a 3% increase in the base distribution charge and adopt RI Energy's five-year revenue projection for the distribution capital expenditure factor
  - Other subcomponents (which are relatively small in size) are assumed to either converge to zero, or increase at or just above inflation
  - Further adjustments are applied to account for the impact of load growth (reducing volumetric charges) and costs associated with EV integration and grid modernization (increasing volumetric charges)

Methodology for Retail Rate Forecast (3)

- **Energy Efficiency:**
  - The energy efficiency charge is modeled as a function of historical spending and three-year anticipated energy efficiency budget by Rhode Island Energy. Further adjustments are applied to account for the impact of load
- **Other Charges:**
  - Renewable Energy Distribution charges are assumed to grow at or just above inflation, and are indexed to the 3-yr average of historic charges
  - Transition charges are assumed to converge to zero as it has historically fluctuated above and below zero and is expected to be phased out
- Rhode Island's base Net Metering credit (for credits accrued beyond the billing month) does not include the Energy Efficiency, RE-Distribution and RES charge (included in total LRS rates)
- However, statute appears to include the RES charge in the credit provided for generation in excess of on-site usage (set at the LRS rate)

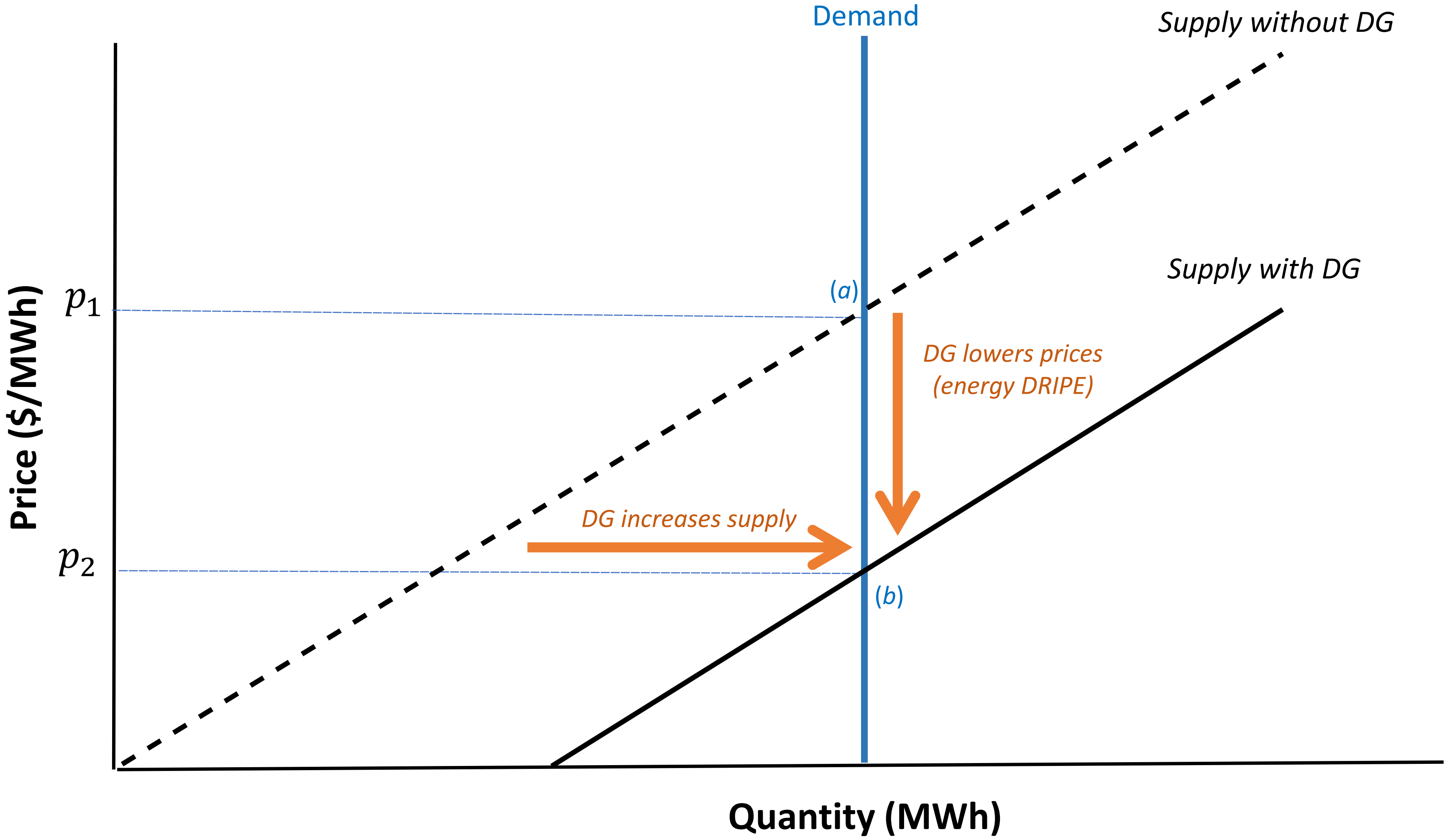
Appendix B: BCA Methodology Details for Reference

Cost – Misc./Other

- Increased transmission and distribution system costs
  - Category used to account for investments specifically required to enable interconnection of DG
  - Assumed to be captured in DG compensation, as these costs are typically borne by interconnecting project through interconnection process
- Participant non-energy costs
  - Intended to capture non-energy related costs borne by participants
  - Examples could include learning about the programs, comparing offers, etc.
  - Assumed to be minimal – not quantified

Benefits - Avoided Costs vs. Price Effects

- For energy and capacity, two types of benefits:
  - Avoided costs (essentially, energy or capacity that doesn't need to be purchased elsewhere)
  - Price effects (reduction in price paid by all consumers because of additional supply)*



** Similar impact in energy efficiency; demand shifts to the left instead of supply shifting to the right – in that context, called demand reduction induced price effect or DRIPE*

Benefits – Avoided Energy and Capacity Value

- **Energy**
  - AESC provides hourly (8760) energy price projections over the course of a calendar year
  - Price projections are applied to estimated solar (or storage) profiles
  - Near-term prices adjusted to account for higher natural gas forward prices since study was initially completed in 2021
- **Capacity**
  - Capacity prices from AESC
  - Solar – requires assumption of coincidence factor (i.e., what % of nameplate capacity available during annual system peak hour)
    - **For Solar:** Derived from estimates for BTM solar in ISO-NE's CELT report; only available through 2031 – assume flat afterwards
    - **For Storage:** - Assume 90% coincidence

Year	Solar Peak Contribution % (% of AC nameplate)
2021	31.8%
2022	29.7%
2023	27.6%
2024	25.6%
2025	23.9%
2026	22.4%
2027	21.2%
2028	20.3%
2029	19.4%
2030	18.6%
2031	17.8%

Benefits - Energy and Capacity Price Effects

- Energy price effects – AESC methodology used to generate 8760 projected 8760 energy price effects
- Capacity price effects – from AESC – vary by COD year
  - Same derate for coincidence as used for avoided capacity value applied
- Cross-fuel price effects
  - In addition to effects noted above, increases in supply in electric market have price effects impact on gas market (electric-to-gas cross-effects), which in turn, has a small impact on the electric market (electric-to-gas-to-electric cross-effects)
  - These impacts are also included in benefits calculations
- Note that all price effects assume that impacts decay over time – in part because lower prices would lead to increased usage

Transmission and Distribution Benefits

- Accurately estimating potential T&D benefits from DERs is challenging; values below informed by methodologies used in other analyses
- Transmission-system benefits
  - Value – from AESC – estimate for Pool Transmission Facilities (PTF) - $98.81/kW-year
  - kW impact (% of name plate) –
    - Solar - use same factors as used for calculating capacity value
    - Storage – 20% of name plate
- Distribution-system
  - Value – calculated for 2023 energy efficiency plan - $8.20/kW-year
  - kW impact
    - *Front of the meter resources* – assume no benefit; while IFOM resources are connected to the distribution-system, the majority (in MW) of development occurs on feeders that become solar saturated, minimizing potential benefits to the distribution system
    - *Behind the meter systems* –
      - *Solar* – 10% times the peak contribution % used to calculate avoided capacity benefit (e.g., for 2031 10%*17.8%=1.8%)
      - *PV+Storage* – 10% of nameplate

Storage T&D benefits are particularly challenging to quantify, as they are highly sensitive to factors such as economic signals, program requirements, interconnection operational restrictions. Iterative process of understanding/calculating benefits → designing programs → modeling results → etc. would help refine projects, but are outside the scope of this current effort.

Benefits - Improved Generation Reliability

- AESC calculates value of improved generation reliability, primarily due to an increase in overall available generation capacity
- Reliability benefits are calculated by multiplying these values by nameplate capacity and coincidence factors used for avoided capacity value
- This benefit would be separate from and additional to potential reliability/resiliency benefit to customers w/ BTM energy storage;
  - That is, primary reliability benefit based on reduced probability of outages occurring
  - A secondary benefit for BTM storage exists – the benefit associated with BTM storage that serves load during an outage (a resilience benefit)
  - This additional resilience benefit is likely small and has not been included

Benefits - REC Value/RES Compliance Costs

- REC Value
  - Incentivized generation will produce RECs eligible for the RI RES
  - SEA will utilize a custom REC price outlook from its New England Renewable Energy Market Outlook (NE-REMO) service that assumes base case conditions, under circumstances in which
    - The New England Clean Energy Connect (NECEC) and currently contracted offshore wind projects reach commercial operation; and
    - The expected amount of additional Rhode Island DG capacity described in Part I (>2 GW) eaches commercial operation by end of year 2033
  - In theory, RECs are intended to capture an array of values, especially environmental ones that would overlap with other values; to avoid double-counting, we propose to subtract REC value from calculated emissions benefits
- We do not assume avoided RES compliance costs for BTM customers
  - In theory, there is a value here – BTM customers that use DG to reduce their load reduce their RES compliance costs
  - However, growing acknowledgement that this represents a type of double-counting (DG is both reducing load and providing generation); impact of double-counting is minimal with low RES targets and BTM DG, but becomes material as state nears 100% renewables

Benefits – Avoided Non-Embedded Emissions

- Certain emissions costs are embedded in values such as energy (through RGGI costs)
- Non-embedded GHG costs capture the costs of emissions not elsewhere accounted for
- AESC provides non-embedded GHG estimates based on several methodologies (see table to right)
  - Narragansett Electric has historically used the New England, electric-sector marginal abatement cost in its energy efficiency filings
  - Given this, we will use this value by default, but may also calculate sensitivities using other methodologies
- AESC also includes estimates for benefits from avoided NO_X emissions, which will be included

Methodology	$/Short-ton (15 year levelized)
Social cost of carbon (damage cost - 2% discount)	$123.56
Social cost of carbon (damage cost - 1% discount)	$393.35
Global marginal abatement cost	$92.48
New England marginal abatement cost (electric sector only)	$130.54
New England marginal abatement cost (multiple sectors)	$493.36

Benefits - Macroeconomic (1)

- Analysis to be conducted using NREL's Jobs and Economic Development Impact (JEDI) models
- JEDI estimates number of jobs and local (state) level economic impacts of constructing & operating projects

Project data inputs include:

- Bill of goods
- Annual O&M costs
- Portion of expenditures to be spent locally
- Financing terms
- Local tax rates
- Construction Costs
- Equipment Costs
- Annual Operating and Maintenance Costs
- Financing Parameters

Results categories include:

- On-site labor and professional services
- Local revenues and supply chain results
- Induced results (driven by reinvestment/spending)

Benefits – Macroeconomic (2)

- JEDI limitations/assumptions
  - Provides estimates, not precise forecasts
  - Gross impacts, not net (common for input-output models)
  - Results are based on assumption that all industrial inputs & factors are used in fixed proportions → impacts will "typically" be linear / no economies of scale
- Possibility of double counting macroeconomic impacts when using economic impact analysis as BCA input
  - E.g., customer re-spending of bill savings → savings may be accounted for in BCA benefits, re-spending may be accounted for in economic impact analysis as an induced result (or inverse, for customer costs increase)
  - Hard to eliminate double-counting, therefore all macroeconomic impact results will be included in the BCA

Low-Moderate Income (LMI) Benefits Discussion

- Evaluating current CRDG framework in context of additional Inflation Reduction Act renewable energy bonus tax credits for LMI customers, in which bonus tax credits are greater than 30% investment credit value available to households and businesses
- Reduced bills for participating LMI customer would produce some benefits that are difficult to quantify, such as reduced energy burden and environmental justice; these are real benefits, but we do not quantify them in the BCA
- Other benefits associated with LMI participants used in the energy efficiency plans are actually benefits to the utility, included in the table to the right
- We plan to include these benefits

Benefit	Description	Value ($ per LMI participant)
Arrearages	Reduced arrearage carrying costs as a result of customers being more able to pay their lower bills	$2.61
Bad debt write-offs	Reduced costs to utility of uncollectable, unpaid balances as a result of customers being more able to pay their lower bills	$3.74
Terminations and reconnections	Reduced costs associated with terminations and reconnections to utility due to nonpayment as a result of customers being more able to pay their lower bills	$0.43
Customer calls and collections	Utility savings in staff time and materials for fewer customer calls as a result of more timely bill payments	$0.58
Notices	Financial savings to utility as a result of fewer notices sent to customers for late payments and terminations	$0.34
	Total per LMI customer	**$7.70**

Benefits - Land Use Benefits

- To quantify carbon sequestration benefits of projects not sited on greenfields (thereby avoiding forest loss), SEA captured the following benefits:
  - **Sequestration Potential (tCO_2/acre):** SEA leveraged USFS EVALIDator estimates of 2021 total Rhode Island forest area and total forest carbon (above and belowground) to calculate carbon sequestration potential per acre statewide
  - **Annual Sequestration Potential (tCO_2 /acre-year):** SEA leveraged USFS EVALIDator estimates for 2021 total Rhode Island tree volume (in cubic feet) and average annual tree volume net growth (in cubic feet/year) to estimate annual carbon sequestration
- The above sources resulted in the following inputs

Unit	Carbon Sequestration Potential	Annual Carbon Sequestration Potential per Year
tCO_2/Acre	74.06	0.57

- Carbon benefits will be assumed to be equivalent to non-embedded GHG emissions benefits
- SEA quantified non-carbon ecological benefits according to a study prepared for the Delaware Valley Regional Planning Commission (southeastern PA) which estimates non-carbon benefits at $653/acre-yr

Benefits – Misc./Other

- There are other benefits referenced in the 4600 framework that are either difficult to quantify or are too small to be quantified for the purposes of this evaluation, including:
  - Net risk benefits (e.g., option value)
  - Innovation and market transformation
  - Customer empowerment
  - Energy security benefits
  - Ancillary services

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