APPENDIX B: Task Report 3 Appendices

Appendix A:

Task 3 - Analysis of Costs and Benefits: Key Assumptions

Massachusetts Net Metering Task Force

PEREGRINE ENERGY GROUP

Sustainable Energy Advantage, LLC

MEISTER CONSULTANTS GROUP

La Capra Associates

Table of Contents:

(2)

A. OVERARCHING ASSUMPTIONS & SIMPLIFYING ASSUMPTIONS

& SIMPLIFYING ASSUMPTIONS

(3)

Key Assumptions

- Analysis performed, and metrics, in Nominal $
- Tax Rates
  - Massachusetts Tax Rates = 8%
  - Federal Tax Rates = 35%
- Nominal Discount rate = 5%
- Federal Investment Tax Credits (ITC) were not assumed to be extended beyond their current statutory timeframe.
- General inflation rate from EIA AEO 2014 GDP IDP
- Inflation rate for ACP from EIA AEO 2014 CPI All Urban Customers

(4)

MA DG Solar Avoids Electric Losses

Raw Data (Utility-specific average & peak loss factors)

		Average T&D	Peak T&D	Avg. excl. TX losses	Peak excl. TX losses
Wtd. Avg MA		5.15%	8.62%	4.35%	7.34%
	weight				
NSTAR	45.28%	4.70%	6.60%	3.77%	5.300%
WMECO	7.79%	5.00%	9.78%	4.45%	8.70%
NGRID - MECO	45.69%	5.60%	10.38%	4.90%	9.077%
NGRID - NEC	0.31%	5.60%	10.38%	4.90%	9.08%
FG&E	0.92%	5.60%	10.38%	4.90%	9.08%

Blue: provided by EDCs
Black: imputed based on similar relationships of peak to average data in blue
Red: used other EDC data as proxies

For Solar Impact ➔ Statewide Factors

Loss Level		Loss Factor
MA Avg. Peak T&D		8.62%
MA Avg. Peak D		7.34%
MA Avg. Production-Wtd Energy T&D		5.58%
MA Avg. Production-Wtd Energy D		4.72%

Production weighting reflects higher-than-average loss reduction due to peak coincidence
(developed using inferred square-function matching average and peak losses)

(5)

Key Considerations for Understanding Results:
Implications of Simplifying Assumptions (1)

1. **Retail Rate Structures Held Constant.** Assumed no change in retail rate structures from current, with respect to any shift from components billed on a per-kWh basis to fixed charges, customer charges, or the establishment of minimum bills. Task Force determined that rate design is important but best addressed before the DPU.
   - A future shift in rate structure away from kWh charges would reduce the avoided cost or revenue realized for behind-the-meter or net metered solar PV projects ➔ Would diminish economics, lead to a slower build-out and a potential shift among installation types unless solar incentives were increased to match (as might be the case under Paths A and B).
   - However, this analysis assumes that a subsector of the marketplace whose retail rate value is not hedged through fixed-price PPA or discount arrangements would derate expectations of future rate revenue to some degree to account for exposure to change of rate structure risk (i.e., host owned <= 25 kW systems under SREC or Path B)
2. **Distribution System Saturation Ignored.** Did not explicitly examine limitations on development caused by saturation of distribution feeders or resulting elevated interconnection costs. Considering such factors would slow the pace of development.(forecast of installations does consider interconnection timelines/constraints).
3. **Technical Potential Saturation Largely Ignored.** Did not explicitly constrain solar technical potential. However, modeling does consider land area, population density, number of residential customers and number of non-residential customers in regards to growth rates and relative potential among utilities. Paths A&B have low growth rates and are not likely to be constrained by technical potential, but are constrained by the policy mechanism itself. Path B is constrained economically. Separately, we have done research that did not find significant near term constraints on brownfield, landfills, or VNM low-moderate income housing sub-sectors. (6)

Key Considerations for Understanding Results:
Implications of Simplifying Assumptions (2)

4. **Ignored Potential Differential Impacts of Installer Incentive Capture.** Did not explicitly assume or analyze installed cost inflation under the more 'generous' policy options (compared to less generous policies), an installer 'incentive capture' phenomenon cited by some analysts, or assume lower installed costs for Policy futures with less generous combined solar and NM incentives.

5. **Ignored Impact of ITC Qualification Peril at 1/1/17.** Did not reflect the likelihood that projects are unwilling to commit to projects with risk exposure to loss of ITC due to interconnection delay or labor shortages in 2016, which may in practice lead to a risk-aversion-driven drop-off in development. Simplified to assume a steadier rate of development influenced by economics and shifted some development back to earlier in the year as participants are well aware of the pending loss of ITC, the risk in being late and are starting development activity earlier.

6. **Assumed Municipal Light Plants Participate Like IOUs in Policy Paths A & B.** MLPs are assumed to participate in Policy Paths A&B the same way as do investor owned utilities (including allowing or not allowing virtual net metering in capped and uncapped scenarios). We treated all MLPs as having a single prototypical rate structure based on Taunton Municipal Lighting Plant rates.

7. **Assumed Future LSE Participation in SREC Floor Price Auctions.** LSEs will fully participate in auction and thus hold marginal SRECs during the auction out years. If LSEs continue to stay on sidelines, it causes extreme additional expenses for NPRs ➔ seems imprudent to assume that this practice would continue indefinitely.

(7)

Key Considerations for Understanding Results:
Implications of Simplifying Assumptions (3)

7. **Ignored Nantucket as a location for solar development.** Did not include Nantucket Electric in the primary analysis

8. **Reclassified SREC-I Projects into SREC-II Sectors.** In order to provide SREC-I results in a comparable manner to other policy paths, we have made best guesses of project reclassification to SREC-II subsectors. Assigning SREC-II subsectors provides a basis of computing and reporting build-out, revenue and cost and analysis.

9. **Treated All Towns as Served by Single Distribution Utility.** In order to assess potential for different project types, utility square miles were computed. Some Massachusetts towns are served by multiple utilities. We assigned each town a unique utility in order to simplify the calculation.

(8)

B. SOLAR PV MODELING

FOR DISPATCH ANALYSIS ANDS COST & BENEFIT ANALYSIS

(9)

Solar PV Production Modeling
Technical Assumptions (1)

- Analysis requires understanding:
  - How many MWh produced per DC MW PV installed?
    - # of SRECs (current policy) is less than this #
  - When production occurs?
    - Value of energy: Coincidence with applicable peaks
- 25-year economic Life of Solar PV Installations
- Key & Simplifying Assumptions:
  - Ignore technological advance and change in mix of fixed vs. tracking
    - Performance (profile and capacity factor) held constant for each installation type across analysis horizon and policy path
  - Degradation: 0.5% energy production per yr.
- AC vs. DC
  - PV rated @ Direct Current (DC)
  - Inverters convert to AC (Alternating Current)
  - Energy on the grid is AC
  - Solar Policy Goals are stated in DC
  - DC to AC conversion efficiency varies by installation type
- Annual Production:
  - Use "Proxy" profile representing simplified composite of different installation types
  - Installation composition may vary over time
  - PV Watts (NREL model estimating production @ specified location) used to estimate production volume and timing
  - PV Watts requires assumptions on tile, azimuth (degrees from due south), AC to DC ratio determinates, shading, etc.
  - MA CEC's Production Tracking System (PTS) provides performance details on current MA PV fleet
  - SEA studied PTS data on existing fleet, developed 'standard' installation characteristics for **composite project type**: Residential, C&I Rooftop, Ground Mount and Solar Canopy installations
  - SEA assumed fraction of each SREC-II subsector associated with each composite project type
  - For PV Watts, assumed single location (Worcester)
- Results: Year 1 for any installation for current SREC-II fleet
  - Capacity Factor (c.f.) (DC) = 14.3%
  - Annual energy: 1627 kWh per AC kW installed
  - Annual energy: 1253 kWh per DC kW installed

(10)

Solar PV Technical Assumptions
Application to Modeling of Solar Policy & Net Metering Impacts (2)

- Each SREC-II subsector has:
  - Composite proxy profile (constant c.f. and production profile over time)
  - Economics of each subsector vary under each policy path ➔ different quantity of PV installed for each subsector under each policy path
  - Policy-path-specific blend of composite profiles and installation proportions ➔ aggregate annual PV production in each year ➔ "Portfolio Annual Production"
    - c.f. was held constant over time and between policy paths as a simplification

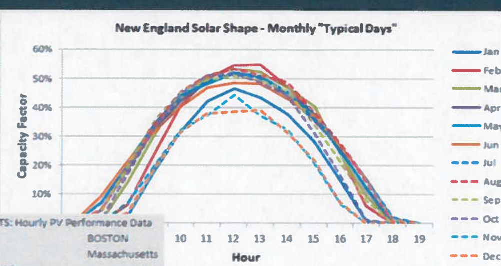
- Area for potential future study:
  - Allow performance over time to vary with evolving blend of system types
  - More nuanced profile as weighted average of projects of varying technology, orientation, tilt, etc.
  - Consider technology advance
  - Would allow looking at possible benefits of encouraging more peak-value orientation, etc.

Residential System	Commercial Rooftop	Ground Mount	Solar Canopy
16%	18%	63%	3%

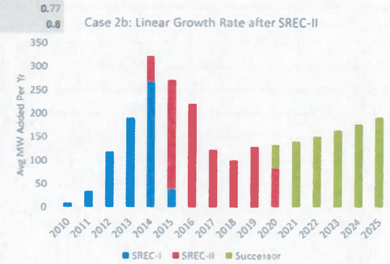
(11)

Solar PV Technical Assumptions
Application to Modeling - Production Modeling in Aurora (3)

- Applies to: market value, energy market price impacts, emission impacts
- Uses a single standard proxy profile of average day per month based on PV Watts profile, 0.77 AC/DC (Boston) (see graph and table: 14% annual c.f. (DC); 1593 kWh per AC kW
  - Same as DOER 2013 Task 3B report
- MW targets in DC.
- Modeling convention: Policy paths have similar solar PV build-out quantities
  - Small differences will not alter per-MWh values materially
- Results of a single Aurora build-out analysis (graph) → scaled to *projected* portfolio annual production in each case using per-MWh Aurora result values

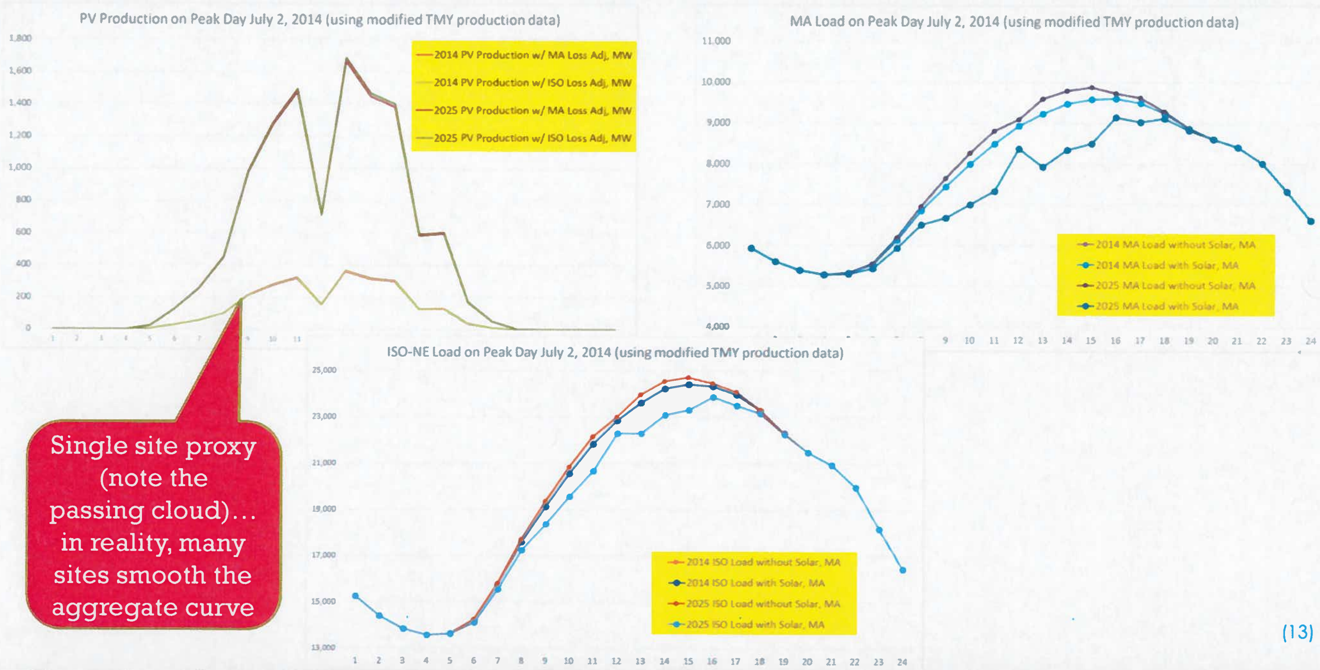


PVWATTS: Hourly PV Performance Data	
City:	BOSTON
State:	Massachusetts
Lat (deg N):	42.37
Long (deg W):	71.03
Elev (m):	5
Array Type:	"Fixed Tilt"
Array Tilt (deg):	42.4
Array Azimuth (deg):	180
DC Rating (kW):	1
DC to AC Derate Factor:	0.77
AC Rating (kW):	0.8



(12)

Solar Peak Impact



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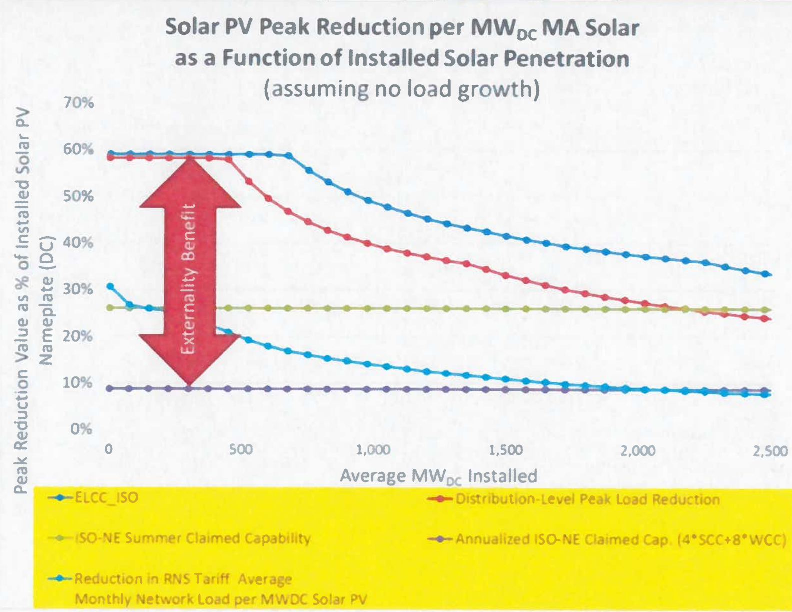
Solar PV Impact on Avoiding G, T & D Capacity



- ISO-NE FCM value (purple):
  - Doesn't vary with PV MW
  - Well below impact on reducing peaks until PV penetrations >> 2500 MW
- Actual PV impact on peaks declines with penetration
  - PV has high peak coincidence
  - But starting to shift time of peak
  - Eventually: the CA 'Duck Diagram'
- G&T peak reduction value (blue) somewhat higher than Distribution value due to different timing of peaks
- Difference between *actual* impact (e.g. lower ISO ICR) and value in FCM market is a *benefit* to all citizens of MA
- FCM value not monetized by generators also a *benefit* to all citizens of MA

(14)

C. WHOLESALE MARKETS & PRODUCTION DISPATCH MODELING ASSUMPTIONS

DISPATCH MODELING & COST/BENEFIT ASSUMPTIONS

(15)

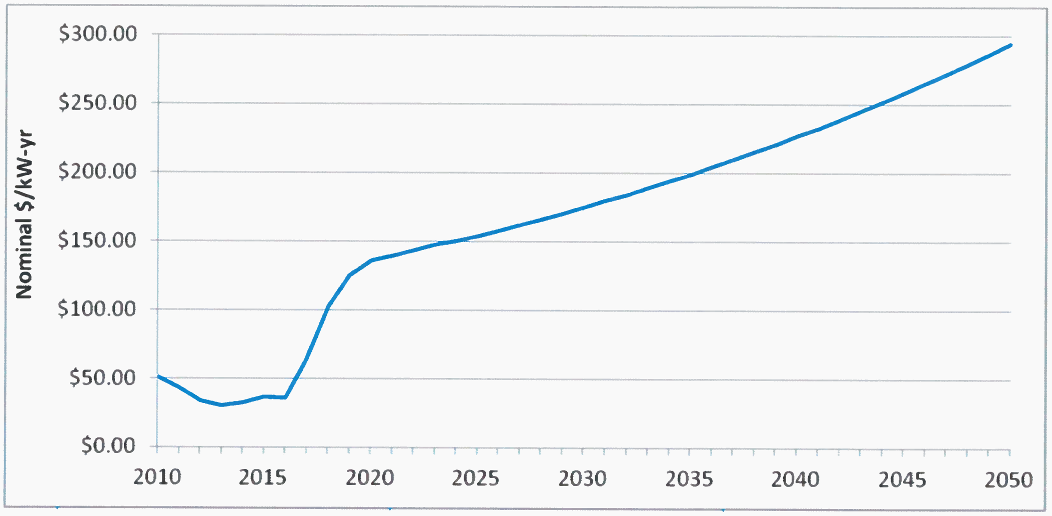
Wholesale Market Assumptions

- ISO-NE Transmission Tariff:
  - 2014 RNS Tariff Rate = $89.80/kW-yr
  - 2014 RNS MA Load Ratio Share = 43.59%
- Installed Capacity Reserve Margin
  - Per ME VOS study, for the year 2017/18, the ISO New England reserve margin was 13.6% based on Net ICR

(16)

Capacity Market Assumptions

- Capacity market prices = Historic actuals, projected values taken from CT 2014 IRP, adjusted to nominal using AEO 2014 GDP deflator, and converted to calendar year



(17)

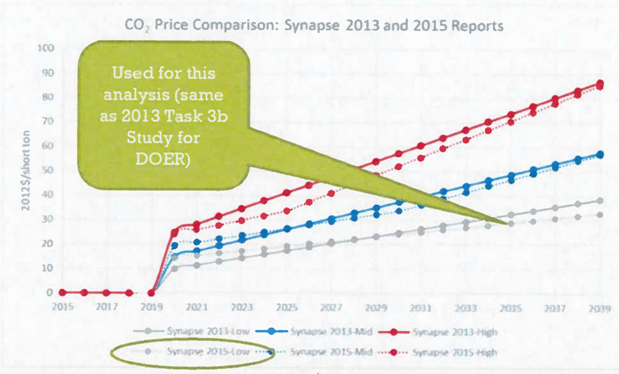
Capacity Value of Intermittent Resources

- Intermittent Resources per : ISO-NE Commercialization and Audit/CCA Establish Procedures for FCM resource (ISO-NE, Apr. 17, 2014)
  - Intermittent reliability hours
  - http://iso-ne.com/static-assets/documents/committees/comm_wkgrps/othr/vrwg/mtrls/a4_commercialization_and_audit.pdf
  - Comparative benchmark for SCC: See slide 20 of this:
    - http://www.iso-ne.com/static-assets/documents/2014/08/2014_final_solar_forecast.pdf
    - 35% SCC used by ISO for estimate

(18)

Internalized (Market) CO_2 Price Assumptions
Used in Dispatch Modeling

Potential Future Carbon Pricing or Equivalent LMP Impact of GHG Regs



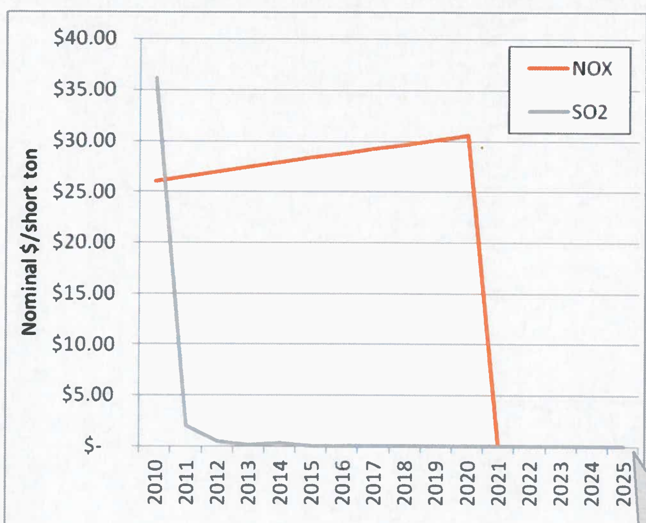
Note: Potential sensitivity of interest for further study: higher carbon price future

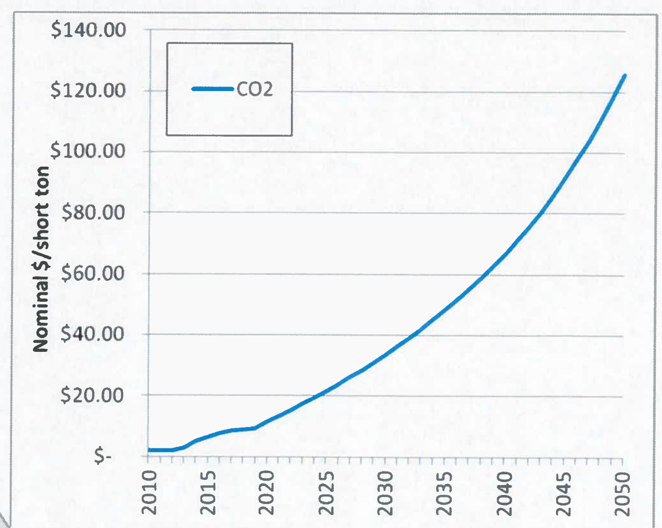
Used as a PROXY

- Start with: Regional Greenhouse Gas Initiative (RGGI) past and projected pricing (projections by ICF for RGGI)
- Transition after 2019 to Synapse Low as a proxy for some combination of future:
  - Federal cap & trade
  - Federal Clean Power Plan impact on energy costs
  - MA Global Warming Solutions Act (and other regional state carbon regs) impact on energy prices

(19)

Emission Pricing Assumptions for Dispatch Modeling

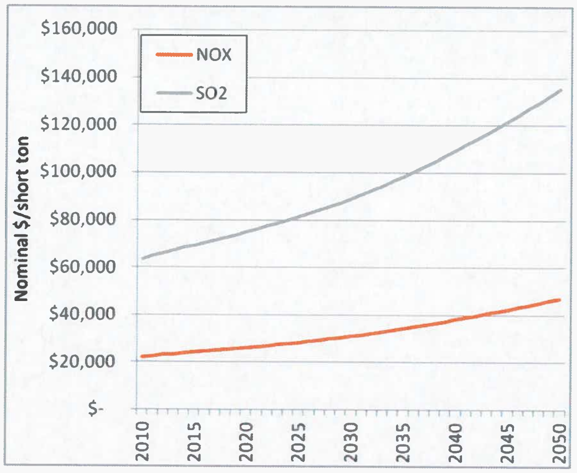


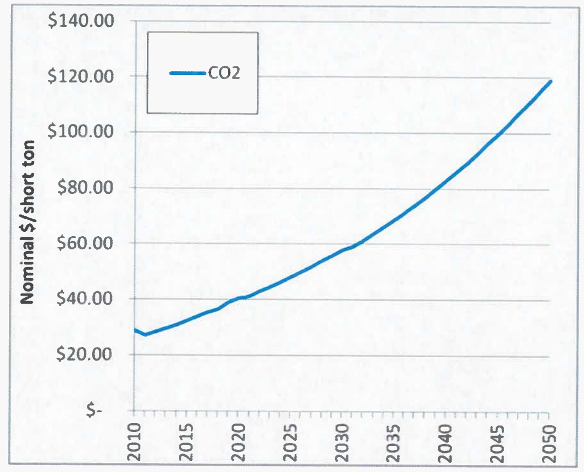


Remains $0 from 2025 onward

(20)

Gross Social Costs of Emissions





- Social costs of NO_X and SO_2 are taken from Table 4-7 of the 2014 EPA "*Regulatory Impact Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants*" report
- Social costs of CO_2 are taken from Table A-1 of the 2013 "*Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis*" prepared by U.S. Interagency Working Group on Social Cost of Carbon under Executive Order 12866

(21)

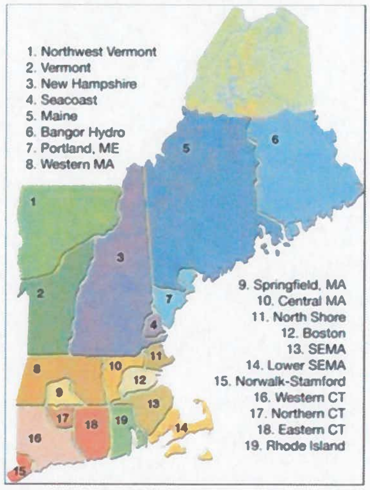
Production Modeling of Impacts (1)

- Case 1a: no policy: remove SREC-I & SREC-II production (keep pre-carve-out PV), assume Class I RPS is met by adding a commensurate amount of wind or (if fall short) natural gas
  - In past, before 1/1/2015 not modeled. Instead:
    - solar not replaced by other supply (onshore wind) but rather all the wind that could be built, was, so RPS supply came up shorter by the amount of SRECs projected, and replaced to the extent supply needed by natural gas
    - Fuel use and emissions changes not modeled; rather, calculated at marginal values
    - Was negligible congestion historically ➔ assume same marginal units (modeled as hypothetical NG unit at composite marginal heat rate
    - Assume no material change in LMPs
  - In future: through 2017 assume no more wind could be built, so substituted by falling short of RPS, met be marginal natural gas; 2018 & thereafter, assume PV substituting with land-based wind
- Case 1b: Assume RPS shortfall made up by natural gas
- Case 2a: 1600 MW by 2020
  - Buildout: Historic (from DOER) + projected (SEA MA-SMS in consultation w/ DOER)
- Case 2b: 1600 MW by 2020 continuing to 2500 MW by 2025
  - Buildout: Extrapolate normalized build per yr and round up to allow for a bit of growth
- Impacts calculated as differences:
  - SREC-I & SREC-II from difference between Case 1 & Case 2a
  - SREC-I, SREC-II & (projected) SREC-III from difference between Case 1 & Case 2b

(22)

Production Cost Modeling (2)

- Geographic distribution assumed to be same as current cumulative build
  - BOSTN = 11 North Shore + 12 Boston
  - CMA = 10 Central MA
  - WMA = 8 Western MA + 9 Springfield
  - SEMA = 13 SEMA + 14 Lower SEMA



- Note: the Aurora modeling was done using a slightly older SEA forecast (vintage Dec. 2014) of SREC Carve-out (current policy) than used for Policy Path A & B.
- SEA's March 2015 Solar Market Study model is better able to address the differential economics of alternative policy paths.
- March 2015 model projects hitting 1600 MW under current policy at a somewhat different pace.
- Use of per-MWH Aurora results scaled to SMS MWH projections used to correct for this difference.

(23)

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MA DOER Net Metering

MODELING ASSUMPTIONS

Presented by: La Capra Associates, Inc. Presented to: Sustainable Energy Advantage, LLC

April 21, 2015

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Introduction: Modelling Overview

- The La Capra Associates NMM uses an hourly chronologic electric energy market simulation model based on the AURORAxmp® software platform (AURORA). The model provides a zonal representation of the electrical system of New England and the neighboring regions. For New England, the zones and corresponding transfer capabilities represented in the model conform to the information provided in ISO New England's Regional System Plan.
- AURORA is a well-established, industry-standard simulation model that uses and captures the effects of multi-area, transmission-constrained dispatch logic to simulate real market conditions. AURORA realistically approximates the formation of hourly energy market clearing prices on a zonal basis using all key market drivers, including fuel and emissions prices, loads, DSM, generation unit operating characteristics, unit additions and retirements, and transmission congestion and losses to capture the dynamics and economics of electricity markets.
- The NMM utilizes a comprehensive database representing the entire Eastern Interconnect, including representations of power generation units, zonal electrical demand, and transmission configurations. EPIS, the developer of AURORA, provides a default database, which La Capra Associates supplements with updates to key inputs for the New England market.

25

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Modeling Assumptions

- ❑ Case assumptions
- ❑ Environmental Policies
- ❑ Regional Demand and DSM
- ❑ Regional Generation
- ❑ Transmission
- ❑ Natural Gas

26

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Four cases run in Aurora

Case 1: No SREC Carve-out (removes MA SREC I and II) and replaces solar with wind resources beginning in 2018

Case 1b: No SREC Carve-out (removes MA SREC I and II)

Case 2a: 1600 MW of solar by 2020 (Current Policy)

Case 2b: 1600 MW of solar by 2020 and continuing to 2500 MW by 2025 with linear growth

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Environmental Policies

- There are two major policy issues affecting the regional market outlooks.
- The two programs particularly impact decisions on generation resource continued operation and new supply choices.

1. The continued strong support for Renewable Portfolio Standards
2. The existing and developing GHG regulations

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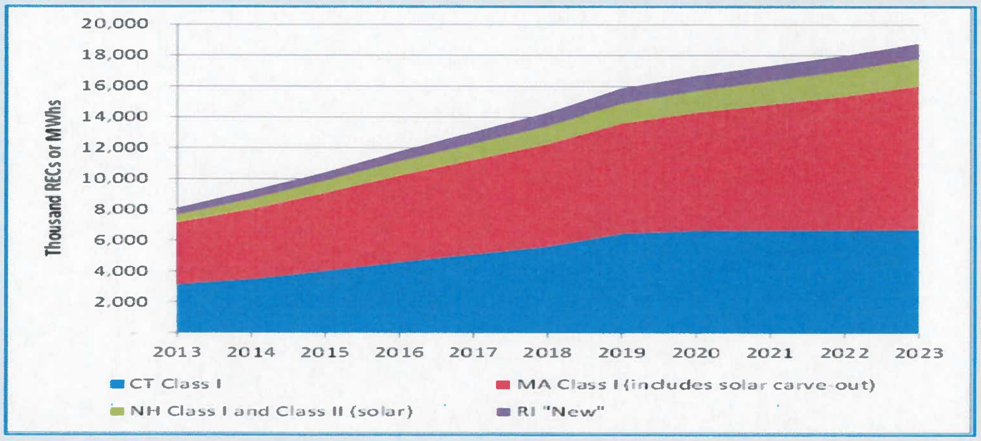
Renewable Energy - Premium Markets RPS

	2014	2015	2016	2017	2018	2019	2020	2021-2023
CT Class 1	11.0%	12.5%	14%	15.5%	17%	19.5%	20.0%	20.0%
MA Class 1	9%	10%	11%	12%	13%	14%	15%	16%+
NH Class 1	5.0%	6.0%	6.9%	7.8%	8.7%	9.6%	10.5%	11.4%+[1]
NH Class 2	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%
RI New	6.5%	6.5%	8.0%	9.5%	11.0%	12.5%	12.5%[2]	12.5%
Load-Weighted Average	9.0%	10.1%	11.2%	12.4%	13.6%	15.1%	15.9%	16.5%+



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Greenhouse Gas Regulations

RGGI

All New England states participate in RGGI, a cap-and-trade program aimed at reducing CO_2 emissions from the power sector. Pricing carbon emissions through a cap-and-trade program affects New England electric energy prices by increasing the variable costs of fossil fuel-fired generators that are almost always on the margin. RGGI allowance prices have been minimal since the program began in 2009 because actual CO_2 emission levels have fallen well below the initial program caps. On February 7, 2013 the RGGI states committed to an Updated Model Rule that would tighten the caps significantly in 2014. A RGGI-commissioned study of the Updated Model Rule projects that emission allowance prices will rise from about $4 (2010$) per ton in 2014 to over $10 (2010$) per ton by 2020.RGGI auction results to-date have benchmarked well to the Updated Model Rule forecast. After 2020, the reference case assumes that a national CO_2 pricing program is implemented and that prices will reflect the “Low” case of Synapse Energy Economics, Inc.’s 2012 Carbon Dioxide Price Forecast.

Federal Policy

EPA released its Clean Power Plan proposal, which aims to cut carbon emissions from existing power plants and enable the US to reduce carbon emissions from the power sector by 30% below 2005 levels. EPA has proposed each state or multi-state collaboration would develop a plan to meet an individual carbon intensity reduction target through any combination of plant efficiency improvements, shifting generation from higher to lower-emitting resources, maintaining and expanding nuclear and renewable generation, and energy efficiency. New England has already implemented programs and policies that would likely generate more carbon dioxide reductions than required under the EPA’s proposal, but the federal proposal would backstop these efforts.

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Regional Electric Demand – Gross Outlook Pre - EE

ISO-NE Peak Demand Outlook

▪ 2013 Normalized Demand		Actual 27,941	MW
▪ 2014 Forecasted Demand		28,290	MW
▪ 2023 Forecasted Demand		31,878	MW
▪ 10 Year CAGR			1.4 %
▪ 10 Year Increase	3,937 MW	11% of 2023 Demand	

ISO-NE Energy Requirements Outlook

▪ 2013 Energy		*est. 135,000*	GWh
▪ 2014 Forecasted Energy		138,910	GWh
▪ 2023 Forecasted Energy		152,347	GWh
▪ 10 Year CAGR			0.7%
▪ 10 Year Increase	3,006 GWh	10% of 2023 Energy	

31

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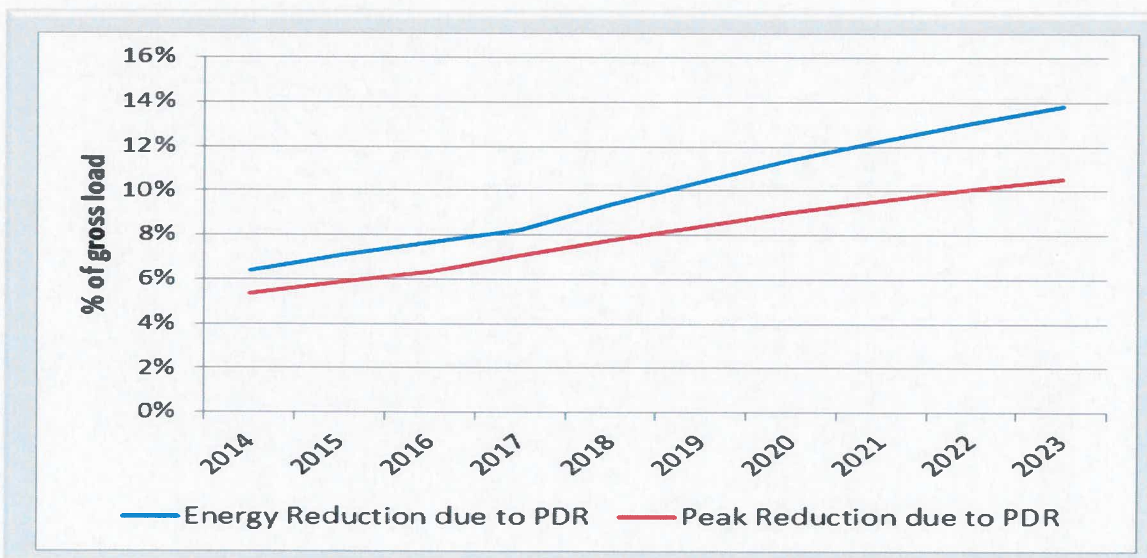
Energy Efficiency Resources



32

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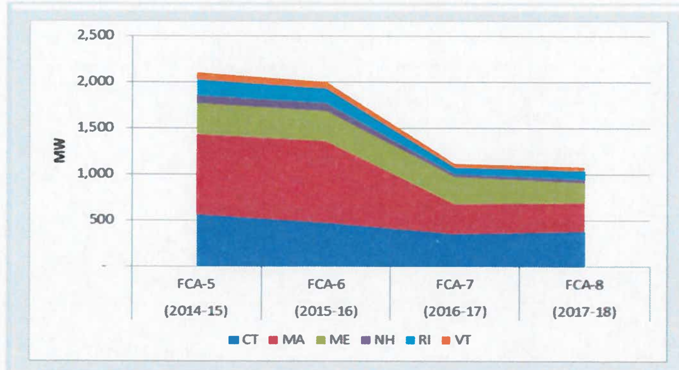
Active Demand Response Resources

- There has been a major reduction in the amount of active DR available to ISO-NE by 201-18
- Total reductions are approximately 1,000 MW
- Proportionately largest reduction in Massachusetts
- This is primarily a result of the new rules requiring DR participation in energy markets
- Further operational requirements on DR could virtually eliminate DR as an FCA resource



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Regional Electric Demand – Net Outlook after EE Effects

ISO-NE Peak Demand Outlook

2013 Normalized Demand	*est 26,000*	MW
2014 Forecasted Demand	26,929	MW
2023 Forecasted Demand	29,206	MW
10 Year CAGR		0.7 %
10 Year Increase	3,006	MW

ISO-NE Energy Requirements Outlook

2013 Energy	*est. 134,000*	GWh
2014 Forecasted Energy	131,037	GWh
2023 Forecasted Energy	134,786	GWh
10 Year CAGR		0.1 %
10 Year Increase	786	GWh

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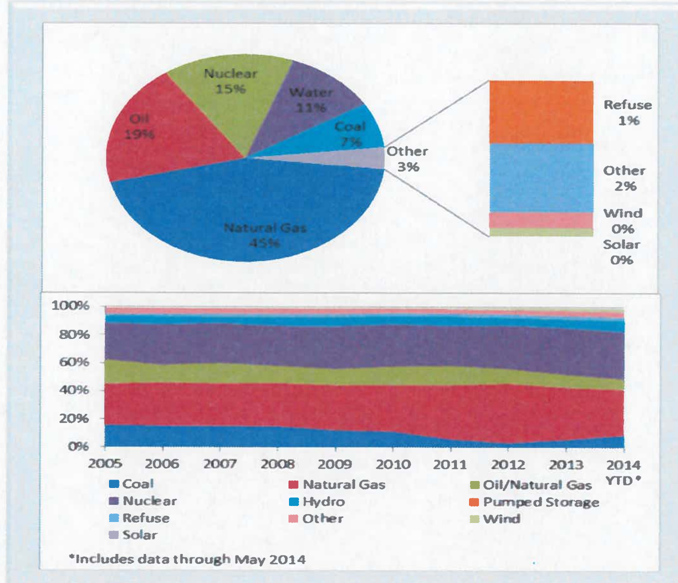
Generation Mix

- **New England remains a natural gas fueled dependent region**
- **Renewables have not yet been established as a major component of generation mix**
- **Natural Gas share of energy increased every year until its highest in 2012, before regional constraints began to push natural gas prices upward**



35

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Generation Resource Retirements

Name	Capacity (MW)	Location	Fuel Type	Status	Planned or Actual Shutdown
Vermont Yankee	600	Vernon, VT	Nuclear	Shutdown Announced	End of 2014
Brayton Point (Units 1-4)	1,500	Somerset, MA	Coal/Oil	Shutdown Announced	2017
Salem Harbor (Units 1-4)	750	Salem, MA	Coal/Oil	Closed	2011-2014
AES Thames	450	Montville, CT	Coal	Demolition	2011
Mt. Tom	150	Holyoke, MA	Coal	Shutdown Announced	2014
Bridgeport Harbor 2	130	Bridgeport Harbor, CT	Oil	Shutdown Announced	2017
Norwalk Harbor (Units 1, 2, 10)	350	Norwalk, CT	Oil	Deactivated	2013

36

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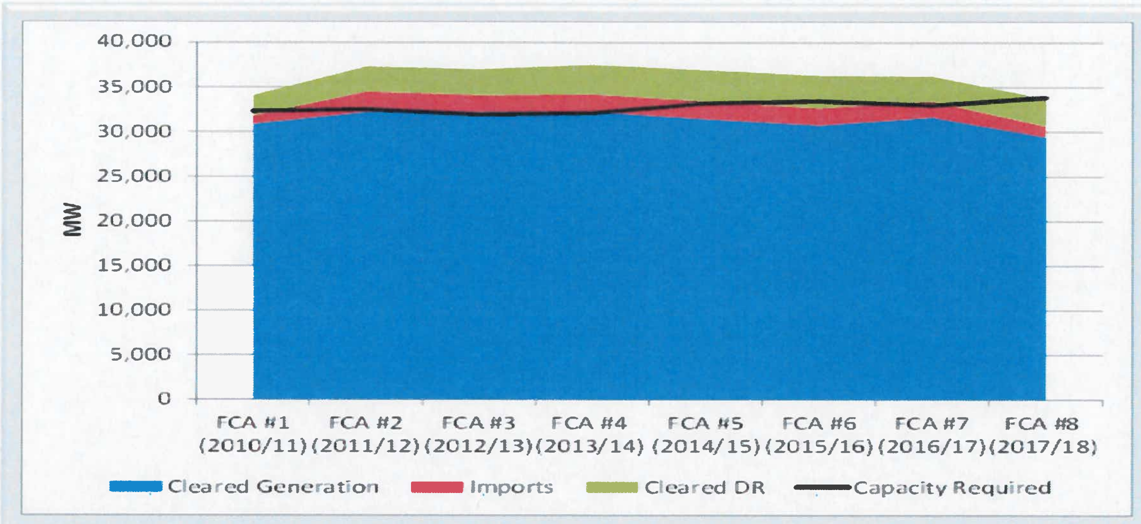
Regional Capacity Outlook

ISO-NE FCA Results showing slight shortfall in 2017/18



37

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Regional Transmission Developments

There are several other transmission projects currently planned or under construction in New England:

- **Maine Power Reliability Program:** six new substations, upgrades to numerous existing substations, and the installation or rebuilding of 440 miles of transmission line in the communities from Eliot to Orrington in Maine. Expected in service date is 2015.
- **New England East-West Solution:** a group of related transmission projects addressing reliability needs in New England, including:
  - **The Greater Springfield Reliability Project:** upgrades to 39 miles of transmission lines between Ludlow, MA and Bloomfield, CT. Now fully in service.
  - **The Interstate Reliability Project:** transmission upgrades spanning three states on a line from Millbury, MA to Card Street Substation in Lebanon, CT. Expected in service date is December 2015.
  - **Central Connecticut Reliability Project:** a project currently in development to remedy reliability concerns in the central Connecticut area.
  - **Rhode Island Reliability Project:** includes several transmission upgrades in Rhode Island, including a new 345 kV line from West Farnum to Kent County. Now in service.
- **Boston Upgrades:** transmission upgrades due to the retirement of Salem Harbor and advanced NEMA/**Boston upgrades increasing Boston import capability in 2014.**

38

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Natural Gas Pricing Methodology

- *Henry Hub:* Prices are a blend of EIA's December 2014 Short-Term Energy Outlook (2013-2015) and EIA's 2014 Annual Energy Outlook (AEO) (2015 and after). In the early years, we rely on the Short-Term Energy Outlook. For years 2017 and 2021, we smooth our forecast by assuming that the price rises at a constant rate. In 2021 and beyond, our forecast follows the AEO2014 exactly.
- *New England Basis Differential:* We developed our near-term basis differential outlook using the average across a recent one year period (1/6/14 – 1/5/15) of daily closing quotes for February 2015 to January 2016 Algonquin City-gates basis swaps. In 2018 and beyond, we revert to a basis that results in a delivered natural gas price equal to the AEO2014 Reference Case forecast for delivered prices to the New England electric industry. We make a straight-line interpolation for basis differential values between 2015 and 2018.

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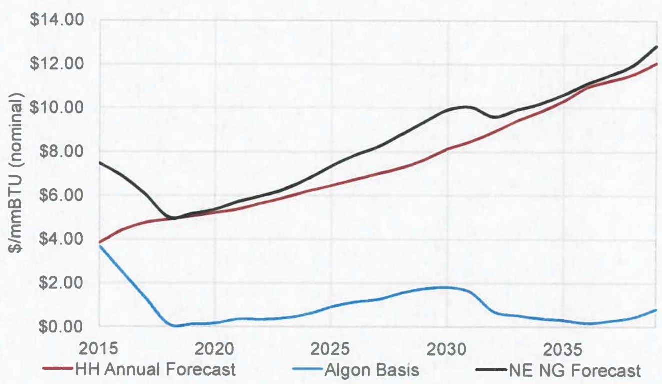
Natural gas price inputs in nominal dollars



Year	HH Annual Forecast	Algon Basis	NE NG Forecast
2015	$3.83	$3.64	$7.47
2016	$4.41	$2.46	$6.87
2017	$4.76	$1.28	$6.04
2018	$4.91	$0.10	$5.01
2019	$5.06	$0.11	$5.17
2020	$5.21	$0.15	$5.37
2021	$5.37	$0.35	$5.72
2022	$5.64	$0.34	$5.98
2023	$5.90	$0.39	$6.30
2024	$6.20	$0.57	$6.77
2025	$6.45	$0.90	$7.34
2026	$6.72	$1.12	$7.84
2027	$7.00	$1.23	$8.23
2028	$7.26	$1.53	$8.79
2029	$7.63	$1.73	$9.37
2030	$8.12	$1.79	$9.92
2031	$8.47	$1.57	$10.04
2032	$8.91	$0.69	$9.60
2033	$9.41	$0.51	$9.92
2034	$9.83	$0.38	$10.21
2035	$10.31	$0.30	$10.61
2036	$10.93	$0.17	$11.10
2037	$11.23	$0.27	$11.50
2038	$11.53	$0.43	$11.96
2039	$12.04	$0.80	$12.84

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End of Presentation

▪ ▪ ▪

Additional Discussion or Questions ?

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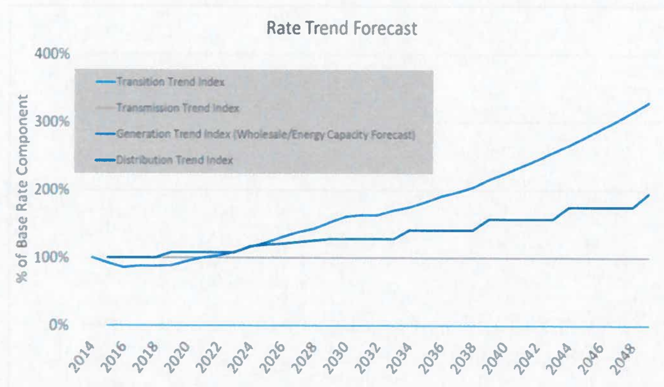
D. AVOIDED RETAIL RATES AND NET METERING REVENUES

AND RELATED ASSUMPTIONS

Rate Trend Forecast:

Assume no fundamental change in rate structures over time

- **Transition** assumed to be 0% escalation after 2015, per EDCs
- **Transmission** assumed to be fixed (0% escalation), per EDCs
- **Distribution** assumed to increase by inflation in steps (corresponding to rate cases) every 5 years, per EDCs
- **Generation** assumed to escalate at index of wholesale blended energy (75%)/capacity (25%)* trend forecast
- **Other Rate Components**: Increase with Inflation, per EDCs
- Recent difference between wholesale energy prices and Basic Service generation rates applied to factor in impact of capacity, reserves, losses, etc.
  - Average of 2014 basic service rates (two procurements) used as the base for forecasting generation charge to avoid overstatement due to unusually high 2015 winter basic service rates



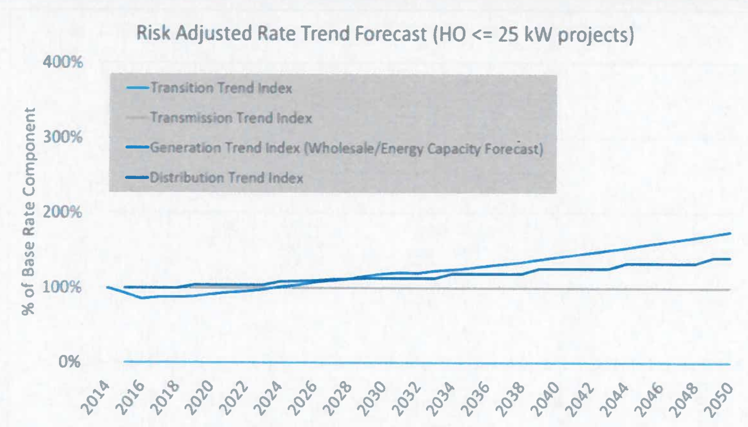
* Portion of spread to trend @ Energy vs. capacity escalator

(43)

Rate Trend Forecast:

For Modeling Project Threshold Return Requirements

- Generators cannot take the uncertain projected retail revenue stream, dependent on long-term factors like carbon pricing, natural gas pricing and capacity market prices, which cannot be relied upon, to the bank
- For 3rd-party owned projects, this risk can and often is hedged (i.e., passed along to the host or NMC off-taker through a fixed-price transaction). We assume going forward that this risk is hedged in such a manner for all 3rd-party owned systems
- For host-owned small projects (<= 25 kW) under SREC and Policy Path B, we assume project owner is exposed to future retail price risk, and makes choices based on a more conservative outlook of future retail rates
- Modeled more conservative future by halving the year-to-year growth in prior slide of **generation** and **distribution** rates after 2018
- Otherwise, under PBIs as studied in Paths A and B, the combined incentive structure serves to hedge this risk



(44)

'Generic" Municipal Light Plant Modeling

- Municipal light territories are modeled in aggregate
- Net metering credit assumed to be load-weighted average of a sample of 10 MLP NMC values (Taunton rates were used as proxy to differentiate G rate from other charges)
  - NMC escalated at wholesale/energy capacity forecast index
- Residential and commercial retail rates calculated as the ratio of EIA "loaded" $/MWh (includes non-kWh charges) of IOUs to MLPs applied to the actual "unloaded" IOU retail rates
  - 40% of MLP retail rate escalated by wholesale/energy capacity forecast index
  - 60% of MLP retail rate escalated by CPI
- Assume 13% of installations in 2015 are in MLPs - based on historic installation trends
- For calculating rate component value, assume MLP rates are made up of basic service (40%), distribution (40%), and transmission(20%)

__Errata Note__: rates used were 20% higher than avg. MLP. This was an error discovered too late in the analysis for revision. Correction of this error would modify results in the following manner: overall growth in installations in the MLP sector would slow moderately, and the overall cost of solar incentives would be slightly higher. This does not alter the nature of overall conclusions in a material manner.

(45)

Applicable Rate Class & Net Metering Class Assumptions

Description	Rate Class	% NM Beyond Billing Month/VNM	% BTM Production w/in Billing Month	Net Metering Class Assumed		
				3rd Party	Host Owned	Public Owned
Residential Roof Mount	R-1	10%	90%		Class 1	
Small Commercial Roof Mount	G-1	5%	95%		Class 1	
Solar Canopy	G-1	5%	95%		Class 2	
Commercial Emergency Power	G-1	5%	95%		Class 1	
Community Shared Solar	G-1	100%	0%		Class 2	
On-Site LIH	G-2	5%	95%		Class 2	
VNM LIH	G-1	100%	0%		Class 2	
Building Mounted	G-2	5%	95%		Class 2	
Small/Medium Ground Mount BTM	G-2	5%	95%		Class 2	
Large Ground Mount BTM	G-2	5%	95%	Class 3		Class 2
Small/Medium Landfill	G-1	100%	0%		Class 2	
Large Landfill	G-1	100%	0%	Class 3		Class 2
Small/Medium Brownfield	G-1	100%	0%		Class 2	
Large Brownfield	G-1	100%	0%	Class 3		Class 2
Medium Ground Mount VNM	G-1	100%	0%		Class 2	
Medium MG	G-1	100%	0%		Class 2	
Large MG	G-1	100%	0%	Class 3		Class 2

Net Metering Credit Rates

- Net meter credits are equal to the following components based on the project type net metering class:

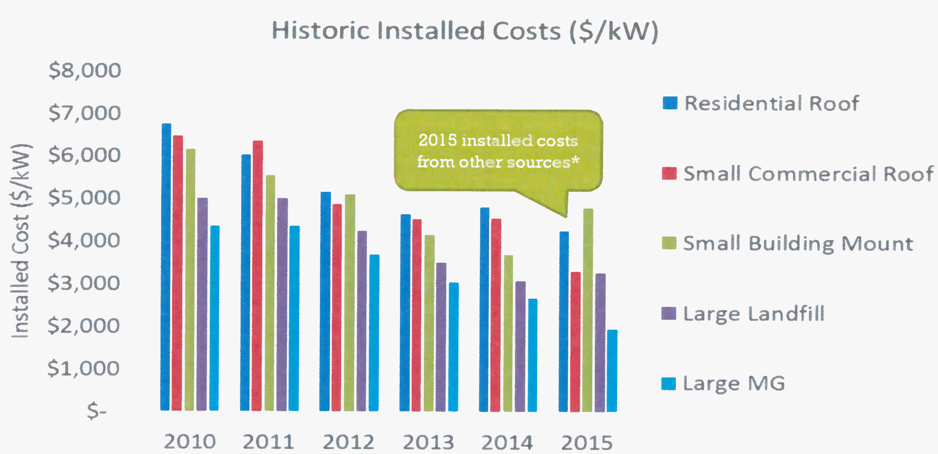
Net Metering Class	Components
Class 1	Generation + Distribution + Transition + Transmission
Class 2	Generation + Distribution + Transition + Transmission
Class 3	Generation + Transition + Transmission

- Small (<= 25 kW) projects always receive net metering (whether uncapped or capped scenario)
- In **Policy Path A** net metering credits are equal to the generation component only

(47)

Historic Installed Costs

- Use DOER SREC-I and SREC-II SQA installed cost data to find the average annual residential installed costs and non-residential by size block for 2010 to 2014



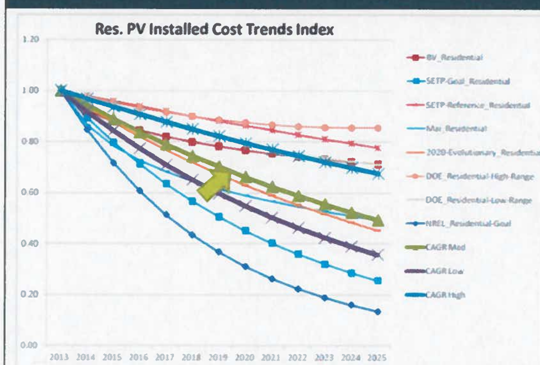
* Discussed in detail PV System Costs section of Appendix

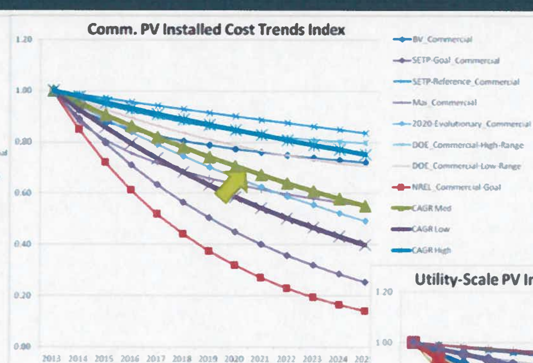
(52)

Historic:
Other PV System Costs & Rates

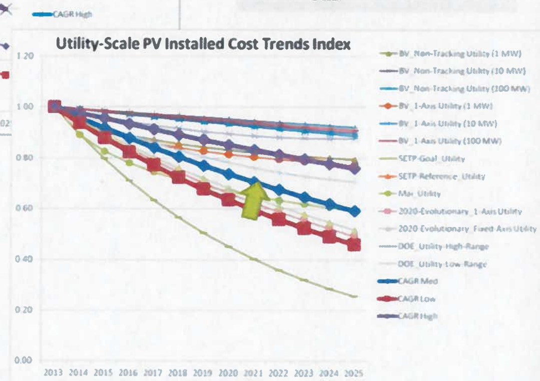
- O&M, customer acquisition, and interconnection costs were backcasted by extrapolating the CPI to 2010 and applying the index to 2015 costs
- Fixed costs (lease payments & PILOT/property taxes) assumed to be fixed back to 2010
- Actual 2010 to 2014 rates for each utility were used to calculate net metering and retail value of production

Installed Cost Forecasts: Trends





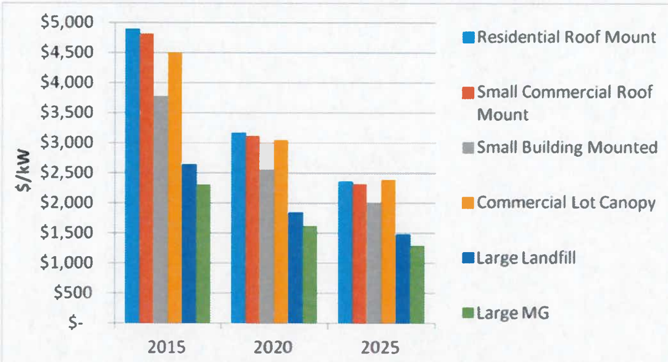
Note: No explicit adjustments made for impact of import duties; Overall impact on module price ~ 8¢/W (per SEAI), portion in effect during 2014 already embedded in forecast



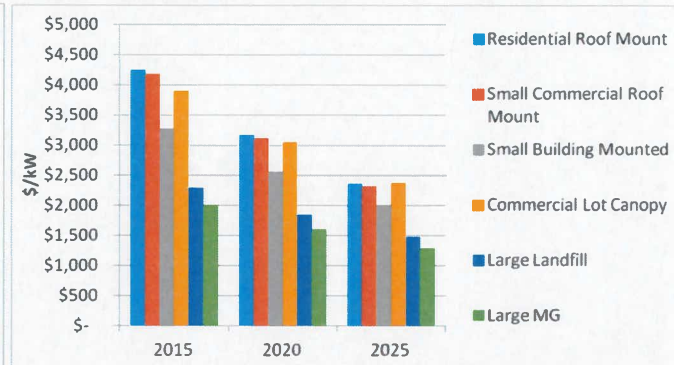
- Survey of available public sources as of late 2014 considered
- Developed trajectory as an index, applied over analysis period to applicable recent historic installed cost data
- 'Medium' used as base case for this analysis

Installed Costs

Host Owned and Public Owned



Third-Party Owned



- The following blocks were also modeled: Campus Lot Canopy, Commercial Emergency Power, Community Shared Solar, On-Site LIH, VNM LIH, Medium Building Mounted, Large Building Mounted, Medium Ground Mount BTM, Large Ground Mount BTM, Small Landfill, Medium Landfill, Small Brownfield, Medium Brownfield, Large Brownfield, Medium Ground Mount VNM, Medium MG
- Blocks of high and low cost systems were also modeled (the above figures represent average cost systems)

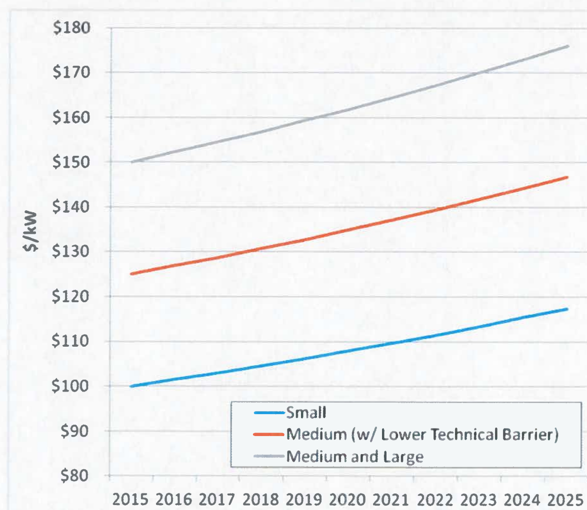
(55)

Interconnection Cost Assumptions

- Based on historical data from public sources and supplemental research
- Assumed interconnections costs vary by project size and technical barrier to interconnect
- Year 1 Interconnection Costs:

Project Size	Modeled Blocks	Year 1 Cost
Small	Residential Roof Mount, Small Commercial Roof Mount, Commercial Lot Canopy, Commercial Emergency Power, On-Site LIH, Small Building Mounted	$100/kW
Medium (with Lower Technical Barrier)	Medium Building Mounted, Medium Ground Mount BTM	$125/kW
Medium and Large	Campus Lot Canopy, Community Shared Solar, VNM LIH, Large Building Mounted, Large Ground Mount BTM, Small Landfill, Medium Landfill, Large Landfill, Small Brownfield, Medium Brownfield, Large Brownfield, Medium Ground Mount VNM, Medium MG, Large MG	$150/kW

- Escalated annually by CPI
- Assumed same interconnection costs across ownership models



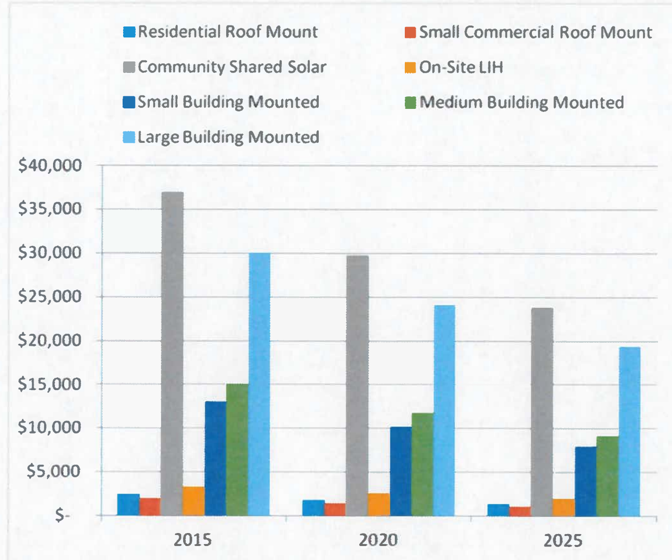
(56)

Customer Acquisition Cost Assumptions

- Based on NREL SunShot soft cost estimates
- Year 1 Customer Acquisition Costs:

Project Type	Year 1 Cost ($/kW)
Residential	$480
Small Commercial	$130
Large Commercial	$30

- Escalated annually using Installed Cost Forecast
- Only applied to third-party owned projects
- Assumed no Customer Acquisition Costs for Canopy, VNM LIH, and Ground Mounted projects



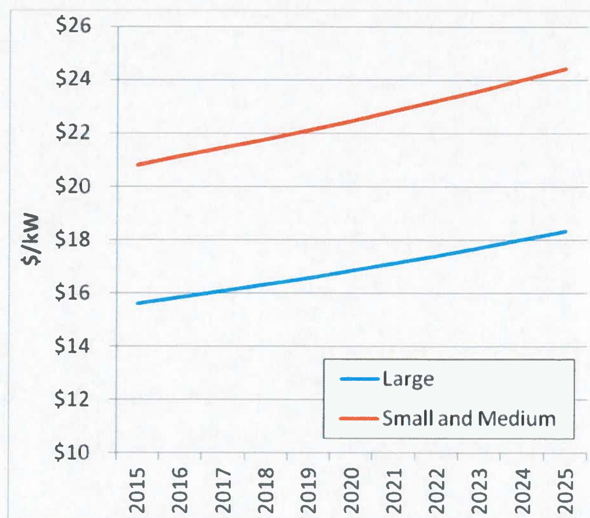
(57)

O&M Cost Assumptions

- Based on historical data from public sources and supplemental research
- Assumed O&M costs "fixed" based on system size not performance
- Assumed O&M costs vary by project size ➔ larger projects will have lower $/kW O&M costs
-

Project Size	Modeled Blocks	Year 1 Cost
Large	Community Shared Solar, VNM LIH, Large Ground Mount BTM, Medium Landfill, Large Landfill, Medium Brownfield, Large Brownfield, Medium MG, Large MG	$16/kW
Small and Medium	Residential Roof Mount, Small Commercial Roof Mount, Commercial Lot Canopy, Campus Lot Canopy, Commercial Emergency Power, On-Site LIH, Small Building Mounted, Medium Building Mounted, Large Building Mounted Medium Ground Mount BTM, Small Landfill, Small Brownfield, Medium Ground Mount VNM	$21/kW

- Escalated annually by CPI
- Assumed same O&M costs across ownership models



(58)

Property Tax (PILOT) and Land Lease Cost Assumptions

- Assumptions developed through market analysis and benchmarking
- PILOT Costs
  - Base Case assumed $10/kW per year, fixed over time
  - Assumed constant across all ownership models
  - Only applied to Ground Mount (incl. Landfill and Brownfield) projects
- Land Lease Costs
  - Base Case assumed $13/kW per year, fixed over time
  - Assumed constant across all ownership models
  - Not applied to Roof Mount projects

(59)

Financing Assumptions:
Related to Risk under each Policy

- For modeling, use simplified capital structure
- Debt:
  - Host & 3rd-party owned systems: on commercial terms
  - Publicly-owned projects: Based on long-term municipal bonds
- Equity
  - Initial developer/sponsor: cash + sweat equity
  - Tax equity to fully monetize tax benefits as generated
  - Where long-term contracts provide stable revenue, YieldCos emerge as another viable source of capital
- Cost & availability of capital is assumed sensitive to:
  - Contract quantity and duration
  - Type, duration & magnitude of incentive
    - Greater revenue certainty → lower cost of capital
    - Fixed PBI is likely to generate interest from more capital, at a lower cost, than a downward sloping soft price floor
- Modeling reflects:
  - Increasing competition among equity providers, including availability and applicability of YieldCo & similar investment vehicles
    - Downward pressure on cost of capital over time
  - Impact of transition from 30% to 10% ITC on capital structure and cost of capital
  - Expiration of ITC for residential host-owned
  - Impact of MA residential solar loan program for small portion of residential installations
    - Implemented as slight interest rate reduction to all residential host-owned projects
  - Considering the degree to which cost of capital advantage of fixed price PBI vs. SREC floor price shrinks as proportion of uncertain revenue shrinks
    - At the limit, if discount to floor is sufficient to finance, cost of capital advantage vanishes

(60)

Financing Assumptions:
Derivation & Application of Key Inputs

	Private, 3rd-Party	Private, Host-Owned	Public, Host-Owned
% Debt	Based on maximum sustainable debt, subject to DSCR (average = 1.35); > rev. certainty (PBI) means > leverage; Debt % also ↑ as ITC % ↓	Estimate of corporate financing structure for major capital investments	Assumed to finance 100% of cost through municipal bonds
Debt Term	Est. of commercial terms. Shorter for SREC structure, longer for PBI	Est. of corporate financing, with guarantee. Term longer for PBI than SREC	20 year bond, all market structures
Int. Rate	Term-specific risk free rate plus market-based premium; assumes volume discount compared to one-off project	Term-specific risk free rate plus market-based premium; rates higher than Private, 3rd-Party due to one-off nature	20-year municipal bond market
Loan Fee	An origination fee, paid to the lender. Set at a level which approximates the market-based premium above the base debt interest rate. For Private, Host-Owned the Loan Fee is assumed built into the term debt interest rate.		
% Equity	All remaining funds required after maximum sustainable debt; a blend of cash, tax and YieldCo equity; blend changes as ITC is reduced	Est. of corporate financing, with guarantee.	Not applicable. Projects financed 100% with municipal bonds.
AT Wtd Cost of Equity	A weighted average of cash, tax and YieldCo equity; subject to downward (competitive) pressure over time	Est. of corporate opportunity cost of other capital investments	Not applicable
WACC	= (%e * Ke) + (%d*Kd*(1-Tax Rate)) The project-specific WACC is used to convert the PBI into an equivalent EPBI (rebate).		Not applicable

(61)

Financing Assumptions: SREC
Private, 3rd-Party Ownership

kW	< 25			100			500			1,000			2,000+		
	'15-'16	'17-'20	'21-'25	'15-'16	'17-'20	'21-'25	'15-'16	'17-'20	'21-'25	'15-'16	'17-'20	'21-'25	'15-'16	'17-'20	'21-'25
% Debt	40%	50%	50%	40%	50%	50%	40%	50%	50%	40%	55%	55%	40%	55%	55%
Debt Term	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
Int. Rate	5.50%	5.75%	6.00%	5.50%	5.75%	6.00%	5.50%	5.75%	6.00%	5.50%	5.75%	6.00%	5.50%	5.75%	6.00%
Loan Fee	2.00%	2.00%	2.25%	2.00%	2.00%	2.25%	2.00%	2.00%	2.25%	2.00%	2.00%	2.25%	2.00%	2.00%	2.25%
% Equity	60%	50%	50%	60%	50%	50%	60%	50%	50%	60%	45%	45%	60%	45%	45%
AT Wtd Cost of Equity	9.5%	8.4%	8.1%	9.5%	8.4%	8.1%	8.9%	8.4%	8.1%	8.9%	7.8%	7.6%	8.9%	7.8%	7.6%
WACC	7.0%	5.9%	5.8%	7.0%	5.9%	5.8%	6.9%	5.9%	5.8%	6.7%	5.4%	5.4%	6.7%	5.4%	5.4%

(62)

Financing Assumptions: SREC
Private Host Ownership

kW	< 25			100			500			1,000			2,000+		
	'15-'16	'17-'20	'21-'25	'15-'16	'17-'20	'21-'25	'15-'16	'17-'20	'21-'25	'15-'16	'17-'20	'21-'25	'15-'16	'17-'20	'21-'25
% Debt	50%	50%	50%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%
Debt Term	15	15	15	12	12	12	12	12	12	12	12	12	12	12	12
Int. Rate	6.50%	6.75%	7.00%	6.50%	6.75%	7.00%	6.00%	6.25%	6.50%	6.00%	6.25%	6.50%	6.00%	6.25%	6.50%
Loan Fee	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
% Equity	50%	50%	50%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%
AT Wtd Cost of Equity	8.0%	8.0%	8.0%	12.0%	10.5%	9.0%	12.0%	10.5%	9.0%	12.0%	10.5%	9.0%	12.0%	10.5%	9.0%
WACC	5.9%	6.0%	6.1%	9.6%	8.6%	7.6%	9.5%	8.5%	7.5%	9.5%	8.5%	7.5%	9.5%	8.5%	7.5%

(63)

Financing Assumptions: SREC
Public host Ownership

kW	< 25			100			500			1,000			2,000+		
	'15-'16	'17-'20	'21-'25	'15-'16	'17-'20	'21-'25	'15-'16	'17-'20	'21-'25	'15-'16	'17-'20	'21-'25	'15-'16	'17-'20	'21-'25
% Debt	-	-	-	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Debt Term	-	-	-	20	20	20	20	20	20	20	20	20	20	20	20
Int. Rate	-	-	-	3.5%	3.75%	4.00%	3.5%	3.75%	4.00%	3.5%	3.75%	4.00%	3.5%	3.75%	4.00%
Loan Fee	-	-	-	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%
% Equity	-	-	-	0	0	0	0	0	0	0	0	0	0	0	0
AT Wtd Cost of Equity	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WACC	-	-	-	3.5%	3.75%	4.00%	3.5%	3.75%	4.00%	3.5%	3.75%	4.00%	3.5%	3.75%	4.00%

(64)

Financing Assumptions: PBI
Private, 3rd-Party Ownership

kW	< 25			100			500			1,000			2,000+		
	'15-'16	'17-'20	'21-'25	'15-'16	'17-'20	'21-'25	'15-'16	'17-'20	'21-'25	'15-'16	'17-'20	'21-'25	'15-'16	'17-'20	'21-'25
% Debt	50%	60%	60%	50%	60%	60%	50%	60%	60%	50%	65%	65%	50%	65%	65%
Debt Term	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
Int. Rate	6.00%	6.25%	6.50%	6.00%	6.25%	6.50%	6.00%	6.25%	6.50%	6.00%	6.25%	6.50%	6.00%	6.25%	6.50%
Loan Fee	2.00%	2.00%	2.25%	2.00%	2.00%	2.25%	2.00%	2.00%	2.25%	2.00%	2.00%	2.25%	2.00%	2.00%	2.25%
% Equity	50%	40%	40%	50%	40%	40%	50%	40%	40%	50%	35%	35%	50%	35%	35%
AT Wtd Cost of Equity	7.6%	7.1%	7.2%	7.6%	7.1%	7.2%	7.1%	6.7%	6.9%	7.3%	6.8%	7.0%	7.3%	6.8%	7.0%
WACC	5.6%	5.1%	5.2%	5.6%	5.1%	5.2%	5.3%	4.9%	5.1%	5.5%	4.8%	5.0%	5.5%	4.8%	5.0%

(65)

Financing Assumptions: PBI
Private Host Ownership

kW	< 25			100			500			1,000			2,000+		
	'15-'16	'17-'20	'21-'25	'15-'16	'17-'20	'21-'25	'15-'16	'17-'20	'21-'25	'15-'16	'17-'20	'21-'25	'15-'16	'17-'20	'21-'25
% Debt	50%	60%	60%	50%	60%	60%	50%	60%	60%	50%	65%	65%	50%	65%	65%
Debt Term	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
Int. Rate	6.50%	6.75%	7.00%	6.50%	6.75%	7.00%	6.00%	6.25%	6.50%	6.00%	6.25%	6.50%	6.00%	6.25%	6.50%
Loan Fee	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
% Equity	50%	40%	40%	50%	40%	40%	50%	40%	40%	50%	35%	35%	50%	35%	35%
AT Wtd Cost of Equity	7.0%	7.0%	7.0%	10.0%	10.0%	9.0%	10.0%	10.0%	9.0%	10.0%	10.0%	9.0%	10.0%	10.0%	9.0%
WACC	5.4%	5.2%	5.3%	6.9%	6.4%	6.1%	6.8%	6.2%	5.9%	6.8%	5.9%	5.7%	6.8%	5.9%	5.7%

(66)

Financing Assumptions: PBI
Public host Ownership

kW	< 25			100			500			1,000			2,000+		
	'15-'16	'17-'20	'21-'25	'15-'16	'17-'20	'21-'25	'15-'16	'17-'20	'21-'25	'15-'16	'17-'20	'21-'25	'15-'16	'17-'20	'21-'25
% Debt	-	-	-	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Debt Term	-	-	-	20	20	20	20	20	20	20	20	20	20	20	20
Int. Rate	-	-	-	3.5%	3.75%	4.00%	3.5%	3.75%	4.00%	3.5%	3.75%	4.00%	3.5%	3.75%	4.00%
Loan Fee	-	-	-	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%
% Equity	-	-	-	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
AT Wtd Cost of Equity	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WACC	-	-	-	3.5%	3.75%	4.00%	3.5%	3.75%	4.00%	3.5%	3.75%	4.00%	3.5%	3.75%	4.00%

F. SREC POLICY ASSUMPTIONS

SREC-I, II AND III

Modeling Extension of Current Policy: SREC-III

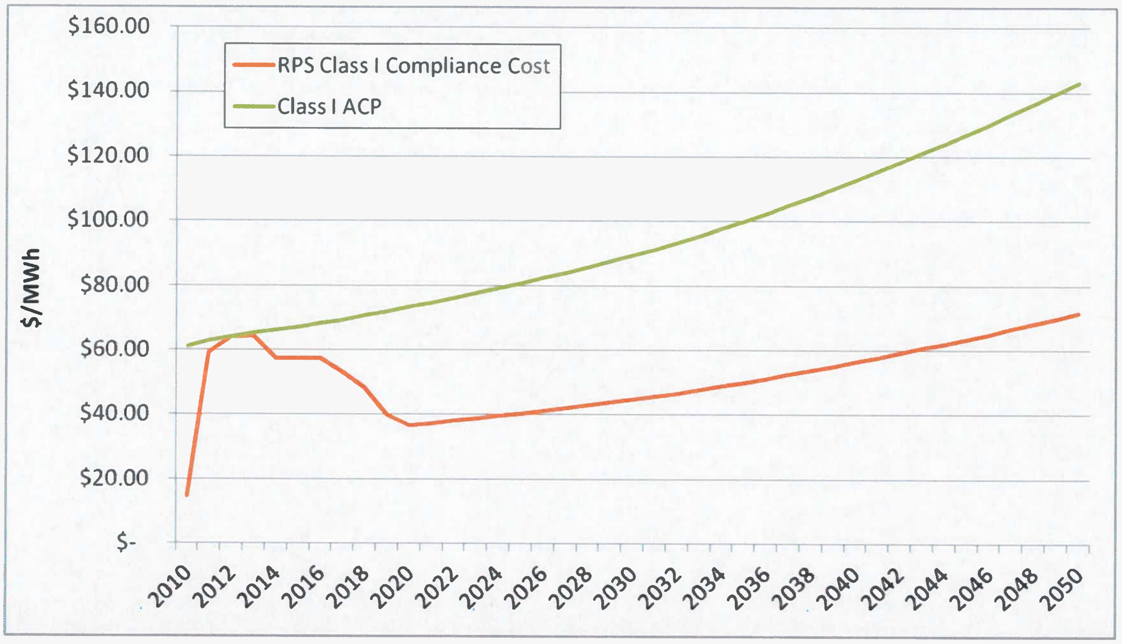
- Treated SREC-III from 1601 MW to 2500 MW dc as a separate tier, so as to not impact SREC-II expected prices and dynamics
- Extended the trend of SACP and floor price declines from those built into SREC-II policy
- Set and used annual MW targets with the objective of getting to 2500 MW by 2025, starting at the market size in last year of SREC-II with small escalator, in an analogous manner to SREC-II
- Modified SEA's proprietary Massachusetts Solar Market Study model of SREC-II with the above changes, using projected system costs and rates, to produce forecasted market buildout and prices.
- *Note: in modeling, SREC-III did not follow the targets, as sectors that were not 'managed' outstripped their targets and led to reaching 2500 MW well before 2025*

(69)

G. CLASS I RPS

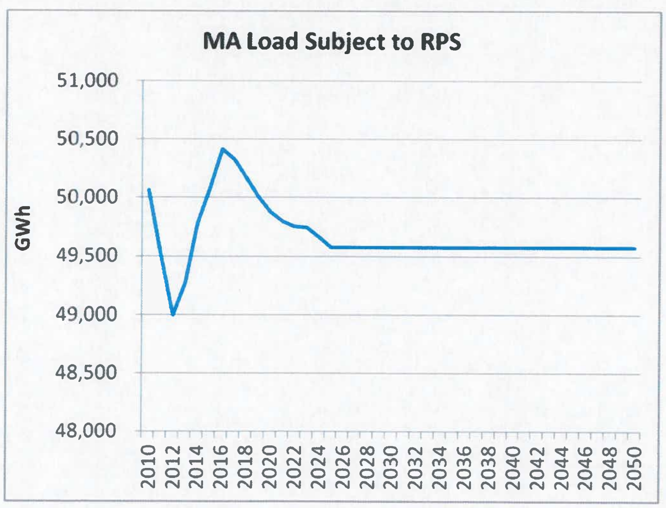
(70)

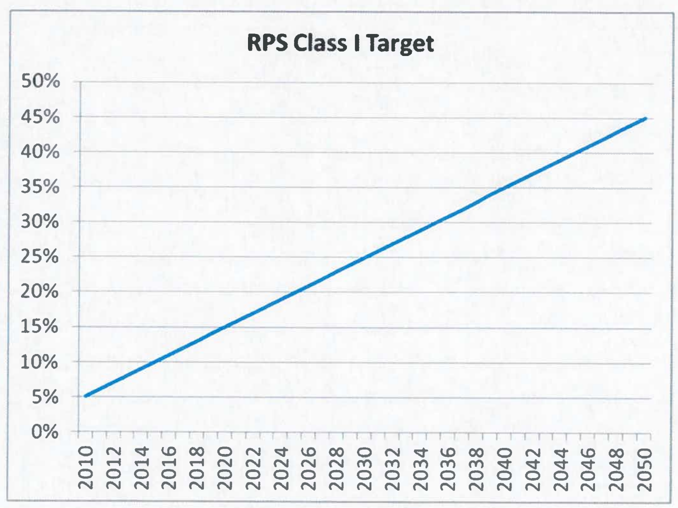
ACP and Avoided Class I RPS Compliance Costs



(71)

MA RPS Load, RPS Exemptions and Class I Targets





- RPS Exemptions = 17.27% of annual load

(72)

H. SUPPLY CURVE

APPROACH AND ASSUMPTIONS

(73)

SREC, Policy Paths A & B:
Overarching Supply Curve Granularity

- The Foundation of the Path A & B Models is a Supply Curve comprised of 612 Production Blocks
- Each Production Block is a Unique Combination of:
  - Project Type (i.e., Residential Roofmount, Medium Landfill, CSS) – 22 Types
  - Utility District (i.e., Munis, NGRID, Nstar BeCO, etc.) – 6 Districts
  - Ownership Type (i.e.. Third Party Owned, Host Owned, Public Owned) - 3 Types
  - Cost Type (High, Medium, Low Cost) - 3 Types (only 6 projects type are further disaggregated by Cost Type)
- MW Installs, MWh Production, Technical Potential, CoE, and Incentives are tracked on a quarterly basis for each of the 612 Production Blocks.

(74)

I. POLICY PATHS A & B

MODELING APPROACH AND ASSUMPTIONS

(75)

Path A & B: Aggregate Program Targets

- Overall Annual Program Targets were set to achieve 2500 MW (including SREC-I & SREC-II) by 2500, with less than 2% increase in targets annually
  - This was done to minimize installation volatility.
- For Capped Scenarios, Initial 2017 Program Aggregate Targets were set at 120 MW, increasing by 2.5 MW, to a Target of 140 MW in 2025.
- For Uncapped Scenarios, Initial 2017 Program Aggregate Targets were set at 120 MW, increasing by 2.0 MW, to a Target of 136 MW in 2025.
  - Increase was set lower than Capped because more MW were installed under SREC-II Uncapped than SREC-II Capped.
- Total Program Targets were set to exceed 2500 MW by 8.8 MW (Capped) and 13 MW (Uncapped) to Ensure 2500 MW target was Hit
  - Overbuild in final quarter of installations was pro-rated to ensure that C/B analysis only modeled costs/benefits for 2500 MW of installations.

(76)

Path A & B: Sector Specific Program Targets

- For Path A and Path B Uncapped, the following Target % were set for each Sector:
  - Sector A Small-Residential: 13.33%
  - Sector A Small-Non-Residential: 1%
  - Of the total % not devoted to Small Residential & Small Non-Residential:
    - Sector A Large: 25%
    - Sector B: 25%
    - Sector C: 25%
    - Sector D (MG): 25%
- For Path A and Path B Uncapped, the following Target % were set for each Sector:
  - Sector A Small-Residential: 13.33%
  - Sector A Small-Non-Residential: 1%
  - Of the total % not devoted to Small Residential & Small Non-Residential:
    - Sector A Large: 10%
    - Sector B: 30%
    - Sector C: 30%
    - Sector MG: 30%
- Sector A Large, Path A & Path B is set at 10% under the Capped Scenario because, as CSS and VNM LIH cannot exist in a NM Capped Scenario, the Sector lacks Resource Potential to hit a 25% Target; the 15% that was not allocated to Sector A Large was evenly distributed between Sector B, C and MG.
- Sector Specific Program Targets directly effect total installs by Path A Large Sectors, as Quarterly Base Solicitation Targets are set equal to one-fourth of Annual Targets.
- Sector Specific Program Targets affect Path A & Path B DBI/PBI & EPBI as Initially Block sizes are set at ½ of the annual 2017 target.

(77)

Path A & B: Starting Resource Potential –Utility Distribution

- Projected 2015-2016 Annual Installs were used as a Base Starting Resource Potential each Project Type (i.e., Residential Roofmount, CSS, Medium MG)
- Base Starting Resource Potential was then divided between each utility for each project type based on whether the Project was Residential, Non-Residential, Land Use Constrained, or Landfill/Brownfield:
  - Residential: Base Starting Potential was divided between each utility based on total % of Residential Customers (i.e. if Residential Roofmount project type has 10 MW of Base Starting Potential, and 10% of Residential customers are in Utility X, Utility X's -Residential Roofmount has 1MW of Resource Potential)
- Non-Residential: Base Starting Potential was divided between each utility based on total % of Non-Residential Customers
- Land-Use Constrained: Base Starting Potential was divided between each utility based on a weighting of open space potential in the utility district (2x Weight), and % Non-Residential Customers in each utility (1x Weight).
  - Open Space Potential is an analytically derived metric based on: 1.) Total Acreage in each Utility; and 2.) Population density in each utility.
- Landfill/Brownfield: Base Starting Potential was divided between each utility based on a weighting of open space potential in the utility district (1x Weight), and % Non-Residential Customers in each utility (2x Weight).

(78)

Path A & B: Starting Resource Potential –Ownership/Cost Distribution

- After dividing Resource Potential between each utility, Resource Potential was then divided between project ownership types (Host Owned, Third Party Owned, Public Owned) based on 2015-2016 SREC-II projections.
  - E.G., Residential Roofmount had roughly a 51-49% relative split between Third Party Owned and Host Owned Projects, thus 51% of technical potential was distributed to 3PO, and 49% to HO projects.

- Finally, after dividing Resource Potential between utilities and ownership type, Resource potential was further divided based on whether the Project Type was segmented by High/Medium/Low Cost.
  - 50% to Medium Cost
  - 25% to Low Cost
  - 25% to High Cost
  - If a project type was not segmented by Cost, naturally no division occurred.

(79)

Path A & B: Ongoing Resource Potential & Growth Rates

- Production Block Resource Potential in each Sector grow at a fixed rate annually, which is equal to MW installed in the previous year multiplied by a Growth Factor.
  - e.g., If a Production Block installs 20 MW in a year, and the Growth factor is 105%, the Production Block will have a technical potential of 21 MW in the subsequent year.
  - Growth Rates set conservatively at 105%-116% for all Sectors.
- Growth/Resource Potential forecasted on an annual basis; as the Model runs quarterly, annual Resource Potential was divided by four (4) to establish quarterly potential.
- Resurrection Rates: In the event a modeled Production Block installs no MW in a year, but Cost ofentry declines to such a degree that said Block could install in subsequent year, Resource Potential is set at ½ of Starting Potential (i.e., Resource Potential in 2017) for installs in the subsequent.

(80)

Path A Large: Competitive Solicitation, Modeling Assumptions

- Solicitations modeled to take place every Quarter.
- Base Quarterly Solicitation Targets equal to ¼ of Annual Sector Targets.
- "Price is Right" Type Solicitation Modeling: Each Quarter, Production Blocks are modeled to be successful until the cumulative MW including the next potential successful marginal Production Block's Resource Capacity is greater than Solicitation Targets (i.e. closest without going over).
  - This means that each solicitation, some % of the MW Target is not fulfilled (unless by chance, Cumulative MW installed for the Marginal Production Block exactly equals the Target);
  - The % of MW target not hit is rolled to the next solicitation as a Remainder.
- Further, a **10% Failure Rate** (i.e. 10% of selected projects fail to reach commercial operation) is assumed; all successful Production Blocks are prorated by 10%, and "Failed MW" are rolled into a solicitation exactly one year in the future.
- Quarterly Targets are equal to: Base Quarterly Target + Remainder & Failed MW carried to that solicitation.
- The combination of Remainder MW and Failure Rates means that MW solicited in each quarterly solicitation increase at a higher rate than initially set Annual Target percentages, and, likewise, that less MW is installed in early years than targeted.
- No Failure Rate assumed in 2025, so that the Model can hit Program Targets.

(81)

Path A Large: Competitive Solicitation, Incentive Assumptions

- Assumed that Production Blocks cannot bid below the value of Electric/NM Rates received from their utility.
- Production Block modeled to bid a Combined Incentive Bid (equal to their needed PBI Incentive + Levelized 15-yr Value of Electric/NM Rates).
- It is assumed that Bidders will strategically bid in such a way as to converge their bids with the marginal bid; thus, in calculating incentives for C/B Analysis, the **calculated Combined Incentive Bid for a successful bidder is equal to the average of the Marginal Bid and the bidders Cost of Entry Bid**.
- PBI Incentive are calculated for C/B analysis by netting out the 15-yr Levelized Value of Electric/NM Rates from the Combined Incentive Bid.

(82)

Path A & B: DBI/PBI, Modeling Assumptions

- Modeled on a Quarterly basis;
- Initial DBI Block sizes set equal to ½ of 2017 Annual Targets;
- All Production Blocks across a Sector compete for the same DBI/PBI Block (however, DBI/PBI incentives vary by utility)
- Model only allows at most two (2) DBI Blocks to fill per quarter;
  - Therefore, total MW that can be installed in a quarter is equal to: total MW remaining in a DBI Block that was partially filled in the previous quarter + the DBI Block Size.
- Model functions by looking at the PBI Incentive Level that each utility is offering, and allowing a Production Block to install in that quarter if PBI is greater than Cost of Entry.

(83)

Path A& B: DBI/PBI, Incentive Assumptions

- Initial DBI/PBI Incentives are set for utility in each Sector, in reference to an Initial Benchmark "Combined Incentive."
- Initial Combined Incentives are calculated by:
  - Selecting a Benchmark Production Block (e.g., Commercial Solar Canopy-NGIRD-Third Party Owned);
  - Determining the Levelized 15-yr Value of Electric/NM Rates for the Benchmark Production Block;
  - Adding this Levelized 15-yr Rate Value to an Optimized DBI/PBI Starting $/MWh incentive (Optimization process discussed in subsequent slide);
- DBI/PBI incentives are then set for each utility by netting out the Levelized 15-yr Rate Value specific to the comparable Benchmark Production Block in that utility from the Combined Incentive.
  - E.g., if the Benchmark Production Block is Commercial Solar Canopy-NGIRD-Third Party Owned, the Levelized 15-yr Rate Value for Commercial Solar Canopy-WMECO-Third Party Owned is netted from the Combined Incentive to determine the initial WMECO DBI/PBI .
- All Utility DBI/PBI incentives in a sector decline by the same specific fixed $/MWh rate:
  - Fixed $/MWh decline used because a % based decline will never "zero-out"
  - Further, analysis showed that program volatility can be better managed with $/MWh than % based DBI/PBI declines.

(84)

Path B: DBI/EPBI Modeling/Incentive Assumptions

- Path B DBI/EPBI was modeled using exactly the same process as DBI/PBI, with the exception that DBI/PBI and Initial Combined Incentives were calculated in $/kW rather than $/MWh; **and**

- The Levelized 15-yr Value of Electric/NM Rates was calculated by discounting the 15-year calculated PBI using the Production Block's weighted average cost of capital (WACC) as a discount rate, rather than Target Equity IRR.

(85)

Path A & B: DBI/PBI & EPBI Incentive Optimization Process

- **Setting DBI/PBI Incentives involves a balancing of several factors:** 2017 install Rates, and level of industry constriction versus 2016; level, constant growth versus volatile growth; setting minimum incentive levels to achieve 2025 targets at lowest cost.
- Because of this, Initial DBI/PBI/EPBI incentives (and decline rates) were set to meet the following policy objectives as closely as possible:
  - 2017 annual installs in each sector being as close to 2017 targets as possible;
  - Sectors hitting their targets (and the Program Hitting 2500 MW) as close to QT. 4, 2025 as possible;
  - Minimize volatility in annual installs from 2017-2025;
  - Incentive levels as low as possible, while still meeting the above objectives, to minimize costs;
- There is more than one solution set (i.e. Initial DBI/PBI or EPBI Incentive Levels **and** $/MWh or $/kW decline rate) that can meet the above parameters;
  - However, more than 100 combinations were tested for each Sector (under each Policy Path and Scenario), and any parallel solution set would be, at best, only marginally better.
- As Path A, Large does not use an open-enrollment system, and incentives are set by bidding rather than centrally planned, no optimization process was necessary.

(86)

J. CALCULATION OF OTHER COST & BENEFIT COMPONENTS

MISC. OTHER ASSUMPTIONS

(87)

'Parametric Analysis' Components

- Where data availability is limited or estimate would require extensive analysis infeasible within scope/timeline, we will make a parametric assumption
  - Example: "x% of cost item retained in-state"
- Consulting team will make an 'anchor' estimate
  - Based on brief literature, review, TF member input, or team judgment.
- When parametric assumption is applied to a model result (i.e. in $ or $/yr), a 10% sensitivity is possible.
  - Example: if anchor parameter is 50%, result will also be calculated as 60%
  - The sensitivity to changes of 10% from the key assumption is easily scaled to give magnitude of sensitivity over a broad range
- When parametric assumption is applied as an input to a complex model, analysis of sensitivities are beyond scope.

(88) ★

Parametric Values Assumptions:

Base Case Values used for All Presented Results; Sensitivity #s used for Sensitivity Analyses

		Parameter	Selected Parameter	Selected Value	Base	Sensitivity	Description
System Installed Costs	CB1.1	A	Base	42%	42%	52.0%*	% of System Installed Cost Expenditures Retained In-State
Ongoing O&M + Insurance Costs	CB1.2	A	Base	64%	64%	74.0%*	% of Ongoing O&M & Insurance Cost Expenditures Retained In-State
ROI (Aggregate Return to Debt & Equity)	CB1.5	A	Base	30%	30%	40.0%*	% of Return to Debt & Equity Investors Retained In-State
Federal Incentives (ITC)	CB1.7a	A	Base	15%	15%	25.0%*	% of Federal ITC retained in-state (assume same as CB1.1-A)
Avoided Generation Capacity Costs	CB5.3	A	Base	28.8%	28.8%	38.8%*	Fraction of solar PV monetizing its value in the FCM; [56 MW of DR PV with CSOs + 85 MW of PV with included on the load side for the FCA9 ICR calculation] divided by 489 MW total forecast = 28.8%
Avoided Trans. Investment - Remote Wind	CB6.1	A	Base	$ 27.50	$ 27.50	$ 35.00	$/MWh Incremental TX cost for Northern New England wind avoided by supplanting need for Class I wind with MA Solar PV
Avoided Trans. Investment - Remote Wind	CB6.1	B	Base	55%	55%	80%	% of incremental TX cost for Northern New England Wind assumed allocated to load
Avoided Transmission Investment - Local	CB6.2	A	Base	30%	30.0%	40%*	% of load on feeders with growth
Avoided Transmission Investment - Local	CB6.2	B	Base	80%	80.0%	90%*	Scalar Adjustment Factor for technical issues (reduces gross value to account for a variety of technical issues preventing solar PV from avoiding investment deferral
Avoided Distribution Investment	CB6.3	A	Base	30%	30.0%	40%*	% of load on feeders with growth
Avoided Distribution Investment	CB6.3	B	Base	50%	50.0%	60%*	Scalar Adjustment Factor for technical issues (reduces gross value to account for a variety of technical issues preventing solar PV from avoiding investment deferral
Avoided Distribution Investment	CB6.3	C	Base	50%	50.0%	60%*	Scalar derating factor applied to distribution level energy losses avoided by solar PV, to reflect that the D investment is at varying locations often close to load, while aggregate D losses measured at D system injection; also reflects that some of literature review sources were already loss adjusted

(89)

System Installed Costs CB1.1

System Installed Costs Retained in State (Inputs)

	Residential			Small Commercial (Roof-top)			Small Commercial (Ground-mount)		
	Cost ($/kW)	% of Total Cost*	% Local Share	Cost ($/kW)	% of Total Cost*	% Local Share	Cost ($/kW)	% of Total Cost*	% Local Share
System Installation Costs									
Installation Costs									
Materials & Equipment									
Mounting (rails, clamps, fittings, etc.)	$168.10	3.4%	50%	$165.52	3.4%	40%	$90.71	3.4%	25%
Modules	$1,637.13	33.4%	0%	$1,612.05	33.4%	0%	$883.43	33.4%	0%
Electrical (wire, connectors, breakers, etc.)	$108.16	2.2%	50%	$106.51	2.2%	40%	$58.37	2.2%	25%
Inverter	$243.37	5.0%	50%	$239.64	5.0%	40%	$131.33	5.0%	25%
Labor									
Installation	$350.68	7.2%	95%	$345.30	7.2%	90%	$189.23	7.2%	70%
Other Costs									
Permitting	$651.64	13.3%	95%	$641.66	13.3%	95%	$351.64	13.3%	95%
Other Costs	$293.02	6.0%	63%	$288.53	6.0%	56%	$158.12	6.0%	56%
Business Overhead	$1,446.19	29.5%	63%	$1,424.04	29.5%	56%	$780.40	29.5%	56%
Sales Tax (Materials & Equipment Purchases)	$0.00	0%	0%	$0.00	0%	0%	$0.00	0%	0%
Total	$4,896.00	100.0%	47%	$4,821.00	100.0%	43%	$2,642.00	100.0%	40%

- % of Total Cost comes from NREL JEDI model default data for Massachusetts
- % Local Share developed from DOER 2013 Task 4 Consultant Report: "*Comparative Regional Economic Impacts of Solar Ownership/Financing Alternatives*" and supplemental research
- Used approx. weighted average of 42%. Based on analysis of annual weighted avg. blend of res, commercial rooftop and ground mount over time. #s were not highly sensitive to evolving blend, varying between 41% and 43%.

(90)

Ongoing O&M + Insurance Costs CB1.2

System O&M Costs Retained in State (Inputs)

	Residential			Small Commercial (Roof-top)			Small Commercial (Ground-mount)		
	Cost ($/kW)	% of Total Cost*	% Local Share	Cost ($/kW)	% of Total Cost*	% Local Share	Cost ($/kW)	% of Total Cost*	% Local Share
Ongoing O&M Costs									
Labor									
Technicians	$11.46	54.6%	100%	$11.46	54.6%	90%	$8.73	54.6%	90%
Materials and Services									
Materials & Equipment	$9.55	45.5%	50%	$9.55	45.5%	40%	$7.28	45.5%	25%
Services	$0.00	0.0%	100%	$0.00	0.0%	56%	$0.00	0.0%	58%
Sales Tax (Materials & Equipment Purchases)	$0.00	0%	0%	$0.00	0%	0%	$0.00	0%	0%
Total	$21.00	100.0%	77%	$21.00	100.0%	67%	$16.00	100.0%	60%

- % of Total Cost comes from NREL JEDI model default data for Massachusetts
- % Local Share developed from DOER 2013 Task 4 Consultant Report: "*Comparative Regional Economic Impacts of Solar Ownership/Financing Alternatives*" and supplemental research
- Used 64%. Based on analysis of annual weighted avg. blend of res, commercial rooftop and ground mount over time. #s were not highly sensitive to evolving blend, varying between 63% and 68%

(91)

Wholesale Market Price Impacts - Energy CB5.1

Wholesale Market Price Impacts

- Wholesale energy market price effects are not in perpetuity
  - Effect of installation in year X assumed to dissipate based on energy DRIPE 2014 dissipation schedule from AESC 2013
- Wholesale energy market price effects only impact purchases from spot market or short-term transactions influenced by spot market. Energy transacted under multi-year energy hedges are not impacted
  - Effect of installation in year X assumed to phase in according to 2014 energy DRIPE hedged energy schedule from AESC 2013

Table 4. Energy Market Effect Adjustments

Production Year(s)	Dissipation %	Load Subject to Solar Market Effects
1	13%	18%
2	18%	72%
3	21%	81%
4	28%	90%
5	34%	90%
6	47%	90%
7	59%	91%
8	70%	91%
9	81%	91%
10	91%	92%
11-end of study period	100%	92%

(92)

Solar Policy Incr. Admin. & Transaction Costs | CB2.4

Estimating EDC Incremental Admin Costs for Policy Paths A & B

- Assumed all EDC labor costs were incremental (whether or not EDC would have sought additional rate recover for these types of costs as core vs. incremental staff in the past)
- Cost estimates by SEA based SEA interpretation of interviews with EDC procurement staff
  - Results not reviewed or endorsed by EDCs
- Categories:
  - One-tome Setup Costs, New Policies (Staffing: EDC staff, legal); systems; tariff design, approvals, training)
    - Small: 2 FTEs, split 75% in 2016, 25% in 2017
    - Large: 2 FTEs, split 75% in 2016, 25% in 2017
    - Same for Paths A & B
  - Solicitation Costs (thru 2025) – Policy Path A (large) only
    - Including core staff, assume 25% of $500K. Assume this is per solicitation round based on LREC/ZREC 1 round/yr. If move to 3 rounds per year, assume some scale economies ==> assume 2.5x the cost of one solicitation
    - Escalate at 4%/yr
  - Ongoing Admin. Costs from 2017 on (Ongoing admin costs (meter reading, hand holding, accounting, payments, recovery filings… (applying from startup to completion, thru 2050)
    - Assume 1.25 FTEs initially for small and 2 for large
    - Costs assumed to escalate annually by 20% of increase in target procurement volume to reflect some increase in labor costs with increased transcaction volume but strong scale economies
  - Transaction Costs for reselling RECs on a $/MWh (Broker Fees Associated with the Sale of RECs if performed through a broker)
    - Assume $1/MWh, applying to 50% of all distribution load (reflecting 1 – today's basic service %)
    - Note: Under SREC, Assume EDCs only purchase for own needs, don't need to resell; SREC Policy 'transactional friction" modeled as part of SREC market mdoel as $2.50 per SREC purchased by LSEs outside of small quantity of direct hedge transactions entered into with generators up-front to support financing
    - Note: corresponding market participant costs for SREC policies embedded in SREC market model, captured there
- Utility staff Average FTE cost used in model: $162,500 fully-loaded, based on input from 2 EDCs

(93)

Solar Policy Incr. Admin. & Transaction Costs | CB2.4

Policy Path A additional developer overhead due to the need to sell both winning and losing bids:

Cust Aq. Cost * (sales/contract under solicitation – sale/contract under open program)

Commercial PV Customer Acquisition Cost ($/kW) (from NREL studies)			
Project Type	Med/Small	Med/Small	Large
Project Size	Not Specified	<250 kW	>250kW
Note	2010 Median	2012 Median	2012 Median
System Design	$0.10	$0.04	$0.01
Marketing/Advertising	$0.01	-	-
Other	$0.08	$0.09	$0.02
Total	$0.19	$0.13	$0.03

Assume $0.05/W as approx. fleet wtd. Avg.

*

Assume 2.5 bids/winning bid

➔ $0.05/W*(2.5-1) = $0.075/W

		# of Projects								
		Round 1			Round 2			Round 3		
		Total	Accepted	Ratio	Total	Accepted	Ratio	Total	Accepted	Ratio
Large ZREC	CL&P	140	21	6.67	52	19	2.74	78	32	2.44
	UI	22	6	3.67	12	4	3.00	8	8	1.00
	Total	162	27	6.00	64	23	2.78	86	40	2.15
Medium ZREC	CL&P	113	47	2.40	157	70	2.24	113	95	1.19
	UI	37	13	2.85	35	24	1.46	50	27	1.85
	Total	150	60	2.50	192	94	2.04	163	122	1.34
		Capacity (MW)								
		Round 1			Round 2			Round 3		
		Total	Accepted	Ratio	Total	Accepted	Ratio	Total	Accepted	Ratio
Large ZREC	CL&P	94.3	12.2	7.73	34.2	12.2	2.80	65.3	27.6	2.37
	UI	12.1	2.6	4.65	7.2	2.4	3.00	5.9	5.9	1.00
	Total	106.4	14.8	7.19	41.4	14.6	2.84	71.2	33.5	2.13
Medium ZREC	CL&P	21.5	8.8	2.44	30.2	14.2	2.13	24.5	18.1	1.35
	UI	7.1	2.5	2.84	6.4	4.4	1.45	9.7	5.1	1.90
	Total	28.6	11.3	2.53	36.6	18.6	1.97	34.2	23.2	1.47

MA Income Taxes	CB1.6.b	Federal Income Taxes	CB1.7b

Estimate of Taxable Discounts & Lease Revenue

Used for estimating income tax impact of these benefits on NOPs

% of Discount Payments Assumed Taxable

Scenario	2015	2020	2025
SREC Capped-1600	35%	80%	80%
SREC Uncapped-1600	35%	80%	80%
SREC Capped-2500	35%	80%	80%
Policy A Capped-1600	35%	80%	80%
Policy A Capped-2500	35%	80%	80%
Policy A Uncapped-1600	35%	80%	80%
Policy A Uncapped-2500	35%	35%	35%
Policy B Capped-1600	35%	80%	80%
Policy B Capped-2500	35%	80%	80%
Policy B Uncapped-1600	35%	80%	80%
Policy B Uncapped-2500	35%	35%	35%

% of Lease Payments Assumed Taxable

Scenario	2015	2020	2025
SREC Capped-1600	75%	80%	80%
SREC Uncapped-1600	75%	80%	80%
SREC Capped-2500	75%	80%	80%
Policy A Capped-1600	75%	80%	80%
Policy A Capped-2500	75%	80%	80%
Policy A Uncapped-1600	75%	80%	80%
Policy A Uncapped-2500	75%	75%	75%
Policy B Capped-1600	75%	80%	80%
Policy B Capped-2500	75%	80%	80%
Policy B Uncapped-1600	75%	80%	80%
Policy B Uncapped-2500	75%	75%	75%

Assumptions made based on SEA side-analysis to estimate evolving mix of taxable and non-taxable lease and PPA/NMC off-takers

(95)

Task Report 3: Appendix B

Appendix B:

Task 3 - Analysis of Costs and Benefits: Detailed Cost and Benefit Result Tables

Massachusetts Net Metering and Solar Task Force

PEREGRINE ENERGY GROUP

Sustainable Energy Advantage, LLC

MEISTER CONSULTANTS GROUP

La Capra Associates

NOP Costs and Benefits – SREC Capped

Benefits

C/B Component ↓	CB Code	2500 MW NPV Benefits (Million $)	2500 MW NPV $/MWh Benefits	1600 MW NPV Benefits (Million $)	1600 MW NPV $/MWh Benefits
Lease Payments	CB1.3	$ 228.2	$ 3.3	$ 209.0	$ 4.8
PILOTs / Property Taxes	CB1.4	$ 152.6	$ 2.2	$ 148.1	$ 3.4
Generation Value of On-site Generation	CB3.1	$ 155.3	$ 2.3	$ 104.1	$ 2.4
Transmission Value of On-site Generation	CB3.2	$ 25.4	$ 0.4	$ 17.5	$ 0.4
Distribution Value of On-site Generation	CB3.3	$ 63.5	$ 0.9	$ 42.5	$ 1.0
Other Retail Bill Components (Trans., EE, RE)	CB3.4	$ 9.6	$ 0.1	$ 7.2	$ 0.2
Offsetting On-site Usage	CB4.1	$ 16.4	$ 0.2	$ 10.6	$ 0.2
Virtual NM	CB4.2	$ 476.0	$ 6.9	$ 476.0	$ 10.9
Total		**$ 1,127.1**	**$ 16.4**	**$ 1,015.0**	**$ 23.3**

Costs

C/B Component ↓	CB Code	2500 MW NPV Costs (Million $)	2500 MW NPV$/MWh Costs	1600 MW NPV Costs (Million $)	1600 MW NPV $/MWh Costs
MA Income Taxes	CB1.6.b	$ 59.2	$ 0.9	$ 52.3	$ 1.2
Federal Income Taxes	CB1.7b	$ 258.8	$ 3.8	$ 228.7	$ 5.2
Total		**$ 318.0**	**$ 4.6**	**$ 280.9**	**$ 6.4**

(2)

NOP Costs and Benefits – SREC Uncapped

Benefits

C/B Component ↓	CB Code	1600 MW NPV Benefits (Million $)	1600 MW NPV $/MWh Benefits
Lease Payments	CB1.3	$ 223.4	$ 5.1
PILOTs / Property Taxes	CB1.4	$ 160.7	$ 3.7
Generation Value of On-site Generation	CB3.1	$ 94.1	$ 2.2
Transmission Value of On-site Generation	CB3.2	$ 15.7	$ 0.4
Distribution Value of On-site Generation	CB3.3	$ 37.9	$ 0.9
Other Retail Bill Components (Trans., EE, RE)	CB3.4	$ 6.6	$ 0.2
Offsetting On-site Usage	CB4.1	$ 9.1	$ 0.2
Virtual NM	CB4.2	$ 525.0	$ 12.1
Total		**$ 1,072.5**	**$ 24.6**

Costs

C/B Component ↓	CB Code	1600 MW NPV Costs (Million $)	1600 MW NPV $/MWh Costs
MA Income Taxes	CB1.6.b	$ 53.0	$ 1.2
Federal Income Taxes	CB1.7b	$ 231.9	$ 5.3
Total		**$ 284.9**	**$ 6.5**

(3)

NOP Costs and Benefits – Policy A Capped

Benefits

C/B Component ↓	CB Code	2500 MW NPV Benefits (Million $)	2500 MW NPV $/MWh Benefits	1600 MW NPV Benefits (Million $)	1600 MW NPV $/MWh Benefits
Lease Payments	CB1.3	$ 304.3	$ 4.3	$ 222.7	$ 5.0
PILOTs / Property Taxes	CB1.4	$ 204.3	$ 2.9	$ 156.8	$ 3.5
Generation Value of On-site Generation	CB3.1	$ 167.8	$ 2.4	$ 104.8	$ 2.3
Transmission Value of On-site Generation	CB3.2	$ 24.9	$ 0.4	$ 17.3	$ 0.4
Distribution Value of On-site Generation	CB3.3	$ 63.9	$ 0.9	$ 42.3	$ 0.9
Other Retail Bill Components (Trans., EE, RE)	CB3.4	$ 10.8	$ 0.2	$ 7.3	$ 0.2
Offsetting On-site Usage	CB4.1	$ 10.2	$ 0.1	$ 9.0	$ 0.2
Virtual NM	CB4.2	$ 453.1	$ 6.4	$ 453.1	$ 10.1
Total		**$ 1,239.3**	**$ 17.6**	**$ 1,013.3**	**$ 22.7**

Costs

C/B Component ↓	CB Code	2500 MW NPV Costs (Million $)	2500 MW NPV$/MWh Costs	1600 MW NPV Costs (Million $)	1600 MW NPV $/MWh Costs
MA Income Taxes	CB1.6.b	$ 63.3	$ 0.9	$ 51.9	$ 1.2
Federal Income Taxes	CB1.7b	$ 277.0	$ 3.9	$ 227.1	$ 5.1
Total		**$ 340.4**	**$ 4.8**	**$ 279.0**	**$ 6.2**

(4)

NOP Costs and Benefits – Policy A Uncapped

Benefits

C/B Component ↓	CB Code	2500 MW NPV Benefits (Million $)	2500 MW NPV $/MWh Benefits	1600 MW NPV Benefits (Million $)	1600 MW NPV $/MWh Benefits
Lease Payments	CB1.3	$ 203.8	$ 2.9	$ 198.1	$ 4.4
PILOTs / Property Taxes	CB1.4	$ 146.8	$ 2.1	$ 142.9	$ 3.2
Generation Value of On-site Generation	CB3.1	$ 134.7	$ 1.9	$ 97.4	$ 2.2
Transmission Value of On-site Generation	CB3.2	$ 19.8	$ 0.3	$ 16.2	$ 0.4
Distribution Value of On-site Generation	CB3.3	$ 48.0	$ 0.7	$ 39.3	$ 0.9
Other Retail Bill Components (Trans., EE, RE)	CB3.4	$ 9.1	$ 0.1	$ 6.8	$ 0.2
Offsetting On-site Usage	CB4.1	$ 11.9	$ 0.2	$ 9.3	$ 0.2
Virtual NM	CB4.2	$ 659.1	$ 9.4	$ 497.8	$ 11.1
Total		**$ 1,233.2**	**$ 17.5**	**$ 1,008.0**	**$ 22.6**

Costs

C/B Component ↓	CB Code	2500 MW NPV Costs (Million $)	2500 MW NPV$/MWh Costs	1600 MW NPV Costs (Million $)	1600 MW NPV $/MWh Costs
MA Income Taxes	CB1.6.b	$ 36.6	$ 0.5	$ 49.0	$ 1.1
Federal Income Taxes	CB1.7b	$ 160.2	$ 2.3	$ 214.2	$ 4.8
Total		**$ 196.8**	**$ 2.8**	**$ 263.2**	**$ 5.9**

(5)

NOP Costs and Benefits – Policy B Capped

Benefits

C/B Component ↓	CB Code	2500 MW NPV Benefits (Million $)	2500 MW NPV $/MWh Benefits	1600 MW NPV Benefits (Million $)	1600 MW NPV $/MWh Benefits
Lease Payments	CB1.3	$ 299.1	$ 4.2	$ 222.4	$ 5.0
PILOTs / Property Taxes	CB1.4	$ 204.3	$ 2.9	$ 157.5	$ 3.5
Generation Value of On-site Generation	CB3.1	$ 160.1	$ 2.3	$ 102.2	$ 2.3
Transmission Value of On-site Generation	CB3.2	$ 25.9	$ 0.4	$ 17.0	$ 0.4
Distribution Value of On-site Generation	CB3.3	$ 66.6	$ 0.9	$ 41.9	$ 0.9
Other Retail Bill Components (Trans., EE, RE)	CB3.4	$ 10.3	$ 0.1	$ 7.1	$ 0.2
Offsetting On-site Usage	CB4.1	$ 11.8	$ 0.2	$ 9.2	$ 0.2
Virtual NM	CB4.2	$ 453.1	$ 6.4	$ 453.1	$ 10.1
Total		**$ 1,231.0**	**$ 17.5**	**$ 1,010.3**	**$ 22.6**

Costs

C/B Component ↓	CB Code	2500 MW NPV Costs (Million $)	2500 MW NPV$/MWh Costs	1600 MW NPV Costs (Million $)	1600 MW NPV $/MWh Costs
MA Income Taxes	CB1.6.b	$ 62.8	$ 0.9	$ 51.7	$ 1.2
Federal Income Taxes	CB1.7b	$ 274.7	$ 3.9	$ 226.0	$ 5.1
Total		**$ 337.5**	**$ 4.8**	**$ 277.7**	**$ 6.2**

(6)

NOP Costs and Benefits – Policy B Uncapped

Benefits

C/B Component ↓	CB Code	2500 MW NPV Benefits (Million $)	2500 MW NPV $/MWh Benefits	1600 MW NPV Benefits (Million $)	1600 MW NPV $/MWh Benefits
Lease Payments	CB1.3	$ 299.1	$ 4.3	$ 222.0	$ 5.0
PILOTs / Property Taxes	CB1.4	$ 213.2	$ 3.0	$ 159.5	$ 3.6
Generation Value of On-site Generation	CB3.1	$ 132.3	$ 1.9	$ 97.1	$ 2.2
Transmission Value of On-site Generation	CB3.2	$ 21.6	$ 0.3	$ 16.1	$ 0.4
Distribution Value of On-site Generation	CB3.3	$ 52.3	$ 0.7	$ 39.2	$ 0.9
Other Retail Bill Components (Trans., EE, RE)	CB3.4	$ 8.8	$ 0.1	$ 6.8	$ 0.2
Offsetting On-site Usage	CB4.1	$ 13.7	$ 0.2	$ 9.6	$ 0.2
Virtual NM	CB4.2	$ 775.5	$ 11.0	$ 520.4	$ 11.7
Total		**$ 1,516.6**	**$ 21.6**	**$ 1,070.8**	**$ 24.0**

Costs

C/B Component ↓	CB Code	2500 MW NPV Costs (Million $)	2500 MW NPV$/MWh Costs	1600 MW NPV Costs (Million $)	1600 MW NPV $/MWh Costs
MA Income Taxes	CB1.6.b	$ 45.7	$ 0.7	$ 53.0	$ 1.2
Federal Income Taxes	CB1.7b	$ 199.9	$ 2.8	$ 232.0	$ 5.2
Total		**$ 245.7**	**$ 3.5**	**$ 285.0**	**$ 6.4**

(7)

CG Costs and Benefits – SREC Capped

Benefits

C/B Component ↓	CB Code	2500 MW NPV Benefits (Million $)	2500 MW NPV $/MWh Benefits	1600 MW NPV Benefits (Million $)	1600 MW NPV $/MWh Benefits
ROI (Aggregate Return to Debt & Equity)	CB1.5	$ -	$ -	$ -	$ -
MA Residential RE Tax Credit	CB1.6.a	$ 134.0	$ 1.9	$ 56.7	$ 1.3
Federal Incentives (ITC)	CB1.7a	$ 1,304.8	$ 18.9	$ 1,258.7	$ 28.9
Direct Incentives (e.g., SRECs)	CB2.1	$ 4,373.7	$ 63.5	$ 3,565.2	$ 81.8
Generation Value of On-site Generation	CB3.1	$ 2,263.9	$ 32.9	$ 940.0	$ 21.6
Transmission Value of On-site Generation	CB3.2	$ 376.3	$ 5.5	$ 163.9	$ 3.8
Distribution Value of On-site Generation	CB3.3	$ 1,010.5	$ 14.7	$ 404.4	$ 9.3
Other Retail Bill Components (Trans., EE, RE)	CB3.4	$ 129.6	$ 1.9	$ 62.7	$ 1.4
Offsetting On-site Usage	CB4.1	$ 323.0	$ 4.7	$ 130.9	$ 3.0
Virtual NM	CB4.2	$ 2,563.0	$ 37.2	$ 2,563.0	$ 58.8
Wholesale Market Sales	CB4.3	$ 69.0	$ 1.0	$ 48.4	$ 1.1
Avoided Generation Capacity Costs	CB5.3	$ 120.1	$ 1.7	$ 77.8	$ 1.8
Total		**$ 12,668.0**	**$ 183.9**	**$ 9,271.7**	**$ 212.8**

Costs

C/B Component ↓	CB Code	2500 MW NPV Costs (Million $)	2500 MW NPV$/MWh Costs	1600 MW NPV Costs (Million $)	1600 MW NPV $/MWh Costs
System Installed Costs	CB1.1	$ 6,696.8	$ 97.2	$ 5,183.0	$ 118.9
Ongoing O&M + Insurance Costs	CB1.2	$ 1,382.7	$ 20.1	$ 980.3	$ 22.5
Lease Payments	CB1.3	$ 228.2	$ 3.3	$ 209.0	$ 4.8
PILOTs / Property Taxes	CB1.4	$ 152.6	$ 2.2	$ 148.1	$ 3.4
MA Income Taxes	CB1.6.b	$ 87.7	$ 1.3	$ 97.8	$ 2.2
Federal Income Taxes	CB1.7b	$ 383.7	$ 5.6	$ 427.9	$ 9.8
Solar Policy Incr. Admin. & Transaction Costs	CB2.4	$ -	$ -	$ -	$ -
Total		**$ 8,931.6**	**$ 129.7**	**$ 7,046.2**	**$ 161.7**

(8)

CG Costs and Benefits – SREC Uncapped

Benefits

C/B Component ↓	CB Code	1600 MW NPV Benefits (Million $)	1600 MW NPV $/MWh Benefits
ROI (Aggregate Return to Debt & Equity)	CB1.5	$ -	$ -
MA Residential RE Tax Credit	CB1.6.a	$ 42.4	$ 1.0
Federal Incentives (ITC)	CB1.7a	$ 1,258.1	$ 28.9
Direct Incentives (e.g., SRECs)	CB2.1	$ 3,526.7	$ 81.0
Generation Value of On-site Generation	CB3.1	$ 766.0	$ 17.6
Transmission Value of On-site Generation	CB3.2	$ 130.9	$ 3.0
Distribution Value of On-site Generation	CB3.3	$ 320.6	$ 7.4
Other Retail Bill Components (Trans., EE, RE)	CB3.4	$ 51.3	$ 1.2
Offsetting On-site Usage	CB4.1	$ 103.1	$ 2.4
Virtual NM	CB4.2	$ 2,891.5	$ 66.4
Wholesale Market Sales	CB4.3	$ -	$ -
Avoided Generation Capacity Costs	CB5.3	$ 77.9	$ 1.8
Total		**$ 9,168.5**	**$ 210.6**

Costs

C/B Component ↓	CB Code	1600 MW NPV Costs (Million $)	1600 MW NPV $/MWh Costs
System Installed Costs	CB1.1	$ 5,136.5	$ 118.0
Ongoing O&M + Insurance Costs	CB1.2	$ 986.7	$ 22.7
Lease Payments	CB1.3	$ 223.4	$ 5.1
PILOTs / Property Taxes	CB1.4	$ 160.7	$ 3.7
MA Income Taxes	CB1.6.b	$ 23.0	$ 0.5
Federal Income Taxes	CB1.7b	$ 100.8	$ 2.3
Solar Policy Incr. Admin. & Transaction Costs	CB2.4	$ -	$ -
Total		**$ 6,631.2**	**$ 152.3**

(9)

CG Costs and Benefits – Policy A Capped

Benefits

C/B Component ↓	CB Code	2500 MW NPV Benefits (Million $)	2500 MW NPV $/MWh Benefits	1600 MW NPV Benefits (Million $)	1600 MW NPV $/MWh Benefits
ROI (Aggregate Return to Debt & Equity)	CB1.5	$ -	$ -	$ -	$ -
MA Residential RE Tax Credit	CB1.6.a	$ 59.8	$ 0.8	$ 43.8	$ 1.0
Federal Incentives (ITC)	CB1.7a	$ 1,335.4	$ 19.0	$ 1,251.3	$ 28.0
Direct Incentives (e.g., SRECs)	CB2.1	$ 4,342.9	$ 61.7	$ 3,592.3	$ 80.4
Generation Value of On-site Generation	CB3.1	$ 1,462.9	$ 20.8	$ 836.4	$ 18.7
Transmission Value of On-site Generation	CB3.2	$ 213.3	$ 3.0	$ 138.6	$ 3.1
Distribution Value of On-site Generation	CB3.3	$ 551.3	$ 7.8	$ 343.0	$ 7.7
Other Retail Bill Components (Trans., EE, RE)	CB3.4	$ 90.3	$ 1.3	$ 55.9	$ 1.3
Offsetting On-site Usage	CB4.1	$ 114.2	$ 1.6	$ 94.9	$ 2.1
Virtual NM	CB4.2	$ 2,409.7	$ 34.2	$ 2,409.7	$ 53.9
Wholesale Market Sales	CB4.3	$ 841.1	$ 11.9	$ 226.7	$ 5.1
Avoided Generation Capacity Costs	CB5.3	$ 119.0	$ 1.7	$ 77.8	$ 1.7
Total		**$ 11,540.0**	**$ 163.8**	**$ 9,070.2**	**$ 202.9**

Costs

C/B Component ↓	CB Code	2500 MW NPV Costs (Million $)	2500 MW NPV$/MWh Costs	1600 MW NPV Costs (Million $)	1600 MW NPV $/MWh Costs
System Installed Costs	CB1.1	$ 6,267.7	$ 89.0	$ 5,094.3	$ 114.0
Ongoing O&M + Insurance Costs	CB1.2	$ 1,270.7	$ 18.0	$ 949.5	$ 21.2
Lease Payments	CB1.3	$ 304.3	$ 4.3	$ 222.7	$ 5.0
PILOTs / Property Taxes	CB1.4	$ 204.3	$ 2.9	$ 156.8	$ 3.5
MA Income Taxes	CB1.6.b	$ 222.2	$ 3.2	$ 123.1	$ 2.8
Federal Income Taxes	CB1.7b	$ 972.0	$ 13.8	$ 538.5	$ 12.0
Solar Policy Incr. Admin. & Transaction Costs	CB2.4	$ 71.2	$ 1.0	$ 17.9	$ 0.4
Total		**$ 9,312.3**	**$ 132.2**	**$ 7,102.7**	**$ 158.9**

(10)

CG Costs and Benefits – Policy A Uncapped

Benefits

C/B Component ↓	CB Code	2500 MW NPV Benefits (Million $)	2500 MW NPV $/MWh Benefits	1600 MW NPV Benefits (Million $)	1600 MW NPV $/MWh Benefits
ROI (Aggregate Return to Debt & Equity)	CB1.5	$ -	$ -	$ -	$ -
MA Residential RE Tax Credit	CB1.6.a	$ 58.8	$ 0.8	$ 43.2	$ 1.0
Federal Incentives (ITC)	CB1.7a	$ 1,337.1	$ 19.0	$ 1,256.4	$ 28.1
Direct Incentives (e.g., SRECs)	CB2.1	$ 3,830.3	$ 54.5	$ 3,446.4	$ 77.2
Generation Value of On-site Generation	CB3.1	$ 1,258.6	$ 17.9	$ 786.3	$ 17.6
Transmission Value of On-site Generation	CB3.2	$ 182.1	$ 2.6	$ 131.8	$ 3.0
Distribution Value of On-site Generation	CB3.3	$ 452.2	$ 6.4	$ 321.1	$ 7.2
Other Retail Bill Components (Trans., EE, RE)	CB3.4	$ 81.2	$ 1.2	$ 53.2	$ 1.2
Offsetting On-site Usage	CB4.1	$ 133.3	$ 1.9	$ 99.0	$ 2.2
Virtual NM	CB4.2	$ 3,513.1	$ 50.0	$ 2,687.3	$ 60.2
Wholesale Market Sales	CB4.3	$ -	$ -	$ -	$ -
Avoided Generation Capacity Costs	CB5.3	$ 119.2	$ 1.7	$ 77.8	$ 1.7
Total		$ 10,966.0	$ 156.0	$ 8,902.6	$ 199.3

Costs

C/B Component ↓	CB Code	2500 MW NPV Costs (Million $)	2500 MW NPV$/MWh Costs	1600 MW NPV Costs (Million $)	1600 MW NPV $/MWh Costs
System Installed Costs	CB1.1	$ 6,236.8	$ 88.7	$ 5,085.4	$ 113.9
Ongoing O&M + Insurance Costs	CB1.2	$ 879.3	$ 12.5	$ 859.7	$ 19.2
Lease Payments	CB1.3	$ 203.8	$ 2.9	$ 198.1	$ 4.4
PILOTs / Property Taxes	CB1.4	$ 146.8	$ 2.1	$ 142.9	$ 3.2
MA Income Taxes	CB1.6.b	$ 211.0	$ 3.0	$ 85.7	$ 1.9
Federal Income Taxes	CB1.7b	$ 922.9	$ 13.1	$ 375.1	$ 8.4
Solar Policy Incr. Admin. & Transaction Costs	CB2.4	$ 69.9	$ 1.0	$ 16.4	$ 0.4
Total		$ 8,670.5	$ 123.3	$ 6,763.3	$ 151.4

(11)

CG Costs and Benefits – Policy B Capped

Benefits

C/B Component ↓	CB Code	2500 MW NPV Benefits (Million $)	2500 MW NPV $/MWh Benefits	1600 MW NPV Benefits (Million $)	1600 MW NPV $/MWh Benefits
ROI (Aggregate Return to Debt & Equity)	CB1.5	$ -	$ -	$ -	$ -
MA Residential RE Tax Credit	CB1.6.a	$ 60.0	$ 0.9	$ 43.8	$ 1.0
Federal Incentives (ITC)	CB1.7a	$ 1,325.7	$ 18.8	$ 1,248.6	$ 27.9
Direct Incentives (e.g., SRECs)	CB2.1	$ 4,173.2	$ 59.2	$ 3,577.5	$ 80.0
Generation Value of On-site Generation	CB3.1	$ 1,468.3	$ 20.8	$ 827.0	$ 18.5
Transmission Value of On-site Generation	CB3.2	$ 228.2	$ 3.2	$ 138.9	$ 3.1
Distribution Value of On-site Generation	CB3.3	$ 575.3	$ 8.2	$ 344.1	$ 7.7
Other Retail Bill Components (Trans., EE, RE)	CB3.4	$ 91.2	$ 1.3	$ 55.4	$ 1.2
Offsetting On-site Usage	CB4.1	$ 131.0	$ 1.9	$ 99.5	$ 2.2
Virtual NM	CB4.2	$ 2,409.7	$ 34.2	$ 2,409.7	$ 53.9
Wholesale Market Sales	CB4.3	$ 838.6	$ 11.9	$ 234.9	$ 5.3
Avoided Generation Capacity Costs	CB5.3	$ 119.2	$ 1.7	$ 77.8	$ 1.7
Total		$ 11,420.4	$ 162.1	$ 9,057.2	$ 202.6

Costs

C/B Component ↓	CB Code	2500 MW NPV Costs (Million $)	2500 MW NPV$/MWh Costs	1600 MW NPV Costs (Million $)	1600 MW NPV $/MWh Costs
System Installed Costs	CB1.1	$ 6,224.5	$ 88.4	$ 5,086.3	$ 113.8
Ongoing O&M + Insurance Costs	CB1.2	$ 1,315.2	$ 18.7	$ 964.8	$ 21.6
Lease Payments	CB1.3	$ 299.1	$ 4.2	$ 222.4	$ 5.0
PILOTs / Property Taxes	CB1.4	$ 204.3	$ 2.9	$ 157.5	$ 3.5
MA Income Taxes	CB1.6.b	$ 188.9	$ 2.7	$ 118.0	$ 2.6
Federal Income Taxes	CB1.7b	$ 826.5	$ 11.7	$ 510.3	$ 11.4
Solar Policy Incr. Admin. & Transaction Costs	CB2.4	$ -	$ -	$ -	$ -
Total		$ 9,058.4	$ 128.6	$ 7,059.2	$ 157.9

(12)

CG Costs and Benefits – Policy B Uncapped

Benefits

C/B Component ↓	CB Code	2500 MW NPV Benefits (Million $)	2500 MW NPV $/MWh Benefits	1600 MW NPV Benefits (Million $)	1600 MW NPV $/MWh Benefits
ROI (Aggregate Return to Debt & Equity)	CB1.5	$ -	$ -	$ -	$ -
MA Residential RE Tax Credit	CB1.6.a	$ 59.1	$ 0.8	$ 43.4	$ 1.0
Federal Incentives (ITC)	CB1.7a	$ 1,334.5	$ 19.0	$ 1,255.7	$ 28.1
Direct Incentives (e.g., SRECs)	CB2.1	$ 3,418.6	$ 48.6	$ 3,496.4	$ 78.3
Generation Value of On-site Generation	CB3.1	$ 1,277.5	$ 18.2	$ 788.0	$ 17.6
Transmission Value of On-site Generation	CB3.2	$ 203.9	$ 2.9	$ 132.3	$ 3.0
Distribution Value of On-site Generation	CB3.3	$ 492.0	$ 7.0	$ 323.5	$ 7.2
Other Retail Bill Components (Trans., EE, RE)	CB3.4	$ 81.3	$ 1.2	$ 53.2	$ 1.2
Offsetting On-site Usage	CB4.1	$ 159.0	$ 2.3	$ 105.2	$ 2.4
Virtual NM	CB4.2	$ 4,197.8	$ 59.7	$ 2,842.0	$ 63.6
Wholesale Market Sales	CB4.3	$ -	$ -	$ -	$ -
Avoided Generation Capacity Costs	CB5.3	$ 119.3	$ 1.7	$ 77.8	$ 1.7
Total		**$ 11,342.9**	**$ 161.3**	**$ 9,117.4**	**$ 204.2**

Costs

C/B Component ↓	CB Code	2500 MW NPV Costs (Million $)	2500 MW NPV$/MWh Costs	1600 MW NPV Costs (Million $)	1600 MW NPV $/MWh Costs
System Installed Costs	CB1.1	$ 6,274.2	$ 89.2	$ 5,095.9	$ 114.1
Ongoing O&M + Insurance Costs	CB1.2	$ 1,365.4	$ 19.4	$ 976.1	$ 21.9
Lease Payments	CB1.3	$ 299.1	$ 4.3	$ 222.0	$ 5.0
PILOTs / Property Taxes	CB1.4	$ 213.2	$ 3.0	$ 159.5	$ 3.6
MA Income Taxes	CB1.6.b	$ 236.6	$ 3.4	$ 91.9	$ 2.1
Federal Income Taxes	CB1.7b	$ 1,035.3	$ 14.7	$ 402.0	$ 9.0
Solar Policy Incr. Admin. & Transaction Costs	CB2.4	$ -	$ -	$ -	$ -
Total		**$ 9,423.8**	**$ 134.0**	**$ 6,947.4**	**$ 155.6**

(13)

NPR Costs and Benefits – SREC Capped

Benefits

C/B Component ↓	CB Code	2500 MW NPV Benefits (Million $)	2500 MW NPV $/MWh Benefits	1600 MW NPV Benefits (Million $)	1600 MW NPV $/MWh Benefits
MA Income Taxes	CB1.6.b	$ 146.9	$ 2.1	$ 150.1	$ 3.4
Displaced RPS Class I Compliance Costs	CB2.3	$ 1,471.6	$ 21.4	$ 921.8	$ 21.2
Generation Value of On-site Generation	CB3.1	$ 135.1	$ 2.0	$ 58.3	$ 1.3
Wholesale Market Sales	CB4.3	$ 3.9	$ 0.1	$ 2.7	$ 0.1
Wholesale Market Price Impacts - Energy	CB5.1	$ 54.4	$ 0.8	$ 64.4	$ 1.5
Avoided Generation Capacity Costs	CB5.3	$ 2,064.4	$ 30.0	$ 1,551.2	$ 35.6
Avoided Transmission Tariff Charges	CB5.5	$ 167.0	$ 2.4	$ 148.4	$ 3.4
Avoided Trans. Investment - Remote Wind	CB6.1	$ 181.8	$ 2.6	$ 112.5	$ 2.6
Avoided Transmission Investment - Local	CB6.2	$ 102.5	$ 1.5	$ 88.6	$ 2.0
Avoided Distribution Investment	CB6.3	$ 232.4	$ 3.4	$ 200.9	$ 4.6
Avoided Environmental Impacts	CB7.1	$ 710.8	$ 10.3	$ 660.0	$ 15.1
Total		**$ 5,270.6**	**$ 76.5**	**$ 3,958.8**	**$ 90.9**

Costs

C/B Component ↓	CB Code	2500 MW NPV Costs (Million $)	2500 MW NPV$/MWh Costs	1600 MW NPV Costs (Million $)	1600 MW NPV $/MWh Costs
MA Residential RE Tax Credit	CB1.6.a	$ 134.0	$ 1.9	$ 56.7	$ 1.3
Direct Incentives (e.g., SRECs)	CB2.1	$ 4,884.4	$ 70.9	$ 3,871.4	$ 88.8
Other Solar Policy Compliance Costs (e.g. SACP)	CB2.2	$ 200.0	$ 2.9	$ 175.7	$ 4.0
Solar Policy Incr. Admin. & Transaction Costs	CB2.4	$ -	$ -	$ -	$ -
Transmission Value of On-site Generation	CB3.2	$ 401.7	$ 5.8	$ 181.4	$ 4.2
Distribution Value of On-site Generation	CB3.3	$ 1,074.0	$ 15.6	$ 446.9	$ 10.3
Other Retail Bill Components (Trans., EE, RE)	CB3.4	$ 125.1	$ 1.8	$ 63.1	$ 1.4
Offsetting On-site Usage	CB4.1	$ 182.4	$ 2.6	$ 78.6	$ 1.8
Virtual NM	CB4.2	$ 1,756.2	$ 25.5	$ 1,751.3	$ 40.2
Total		**$ 8,757.8**	**$ 127.1**	**$ 6,625.1**	**$ 152.0**

(14)

NPR Costs and Benefits – SREC Uncapped

Benefits

C/B Component ↓	CB Code	1600 MW NPV Benefits	1600 MW NPV $/MWh Benefits
MA Income Taxes	CB1.6.b	$ 76.1	$ 1.7
Displaced RPS Class I Compliance Costs	CB2.3	$ 893.5	$ 20.5
Generation Value of On-site Generation	CB3.1	$ 48.0	$ 1.1
Wholesale Market Sales	CB4.3	$ -	$ -
Wholesale Market Price Impacts - Energy	CB5.1	$ 64.4	$ 1.5
Avoided Generation Capacity Costs	CB5.3	$ 1,549.3	$ 35.6
Avoided Transmission Tariff Charges	CB5.5	$ 148.2	$ 3.4
Avoided Trans. Investment - Remote Wind	CB6.1	$ 112.5	$ 2.6
Avoided Transmission Investment - Local	CB6.2	$ 88.5	$ 2.0
Avoided Distribution Investment	CB6.3	$ 200.6	$ 4.6
Avoided Environmental Impacts	CB7.1	$ 660.0	$ 15.2
Total		**$ 3,841.1**	**$ 88.2**

Costs

C/B Component ↓	CB Code	1600 MW NPV Costs (Million $)	1600 MW NPV $/MWh Costs
MA Residential RE Tax Credit	CB1.6.a	$ 42.4	$ 1.0
Direct Incentives (e.g., SRECs)	CB2.1	$ 3,812.7	$ 87.6
Other Solar Policy Compliance Costs (e.g. SACP)	CB2.2	$ 167.1	$ 3.8
Solar Policy Incr. Admin. & Transaction Costs	CB2.4	$ -	$ -
Transmission Value of On-site Generation	CB3.2	$ 146.6	$ 3.4
Distribution Value of On-site Generation	CB3.3	$ 358.6	$ 8.2
Other Retail Bill Components (Trans., EE, RE)	CB3.4	$ 52.2	$ 1.2
Offsetting On-site Usage	CB4.1	$ 60.3	$ 1.4
Virtual NM	CB4.2	$ 1,920.0	$ 44.1
Total		**$ 6,559.9**	**$ 150.7**

(15)

NPR Costs and Benefits – Policy A Capped

Benefits

C/B Component ↓	CB Code	2500 MW NPV Benefits (Million $)	2500 MW NPV $/MWh Benefits	1600 MW NPV Benefits (Million $)	1600 MW NPV $/MWh Benefits
MA Income Taxes	CB1.6.b	$ 285.5	$ 4.1	$ 175.0	$ 3.9
Displaced RPS Class I Compliance Costs	CB2.3	$ 1,552.6	$ 22.0	$ 961.4	$ 21.5
Generation Value of On-site Generation	CB3.1	$ 91.1	$ 1.3	$ 52.6	$ 1.2
Wholesale Market Sales	CB4.3	$ 47.0	$ 0.7	$ 12.7	$ 0.3
Wholesale Market Price Impacts - Energy	CB5.1	$ 54.4	$ 0.8	$ 64.4	$ 1.4
Avoided Generation Capacity Costs	CB5.3	$ 2,103.3	$ 29.9	$ 1,552.6	$ 34.7
Avoided Transmission Tariff Charges	CB5.5	$ 172.6	$ 2.4	$ 148.4	$ 3.3
Avoided Trans. Investment - Remote Wind	CB6.1	$ 181.8	$ 2.6	$ 112.5	$ 2.5
Avoided Transmission Investment - Local	CB6.2	$ 107.3	$ 1.5	$ 90.7	$ 2.0
Avoided Distribution Investment	CB6.3	$ 243.2	$ 3.5	$ 205.6	$ 4.6
Avoided Environmental Impacts	CB7.1	$ 710.8	$ 10.1	$ 660.0	$ 14.8
Total		**$ 5,549.5**	**$ 78.8**	**$ 4,035.8**	**$ 90.3**

Costs

C/B Component ↓	CB Code	2500 MW NPV Costs (Million $)	2500 MW NPV$/MWh Costs	1600 MW NPV Costs (Million $)	1600 MW NPV $/MWh Costs
MA Residential RE Tax Credit	CB1.6.a	$ 59.8	$ 0.8	$ 43.8	$ 1.0
Direct Incentives (e.g., SRECs)	CB2.1	$ 4,589.4	$ 65.2	$ 3,838.8	$ 85.9
Other Solar Policy Compliance Costs (e.g. SACP)	CB2.2	$ 191.1	$ 2.7	$ 191.1	$ 4.3
Solar Policy Incr. Admin. & Transaction Costs	CB2.4	$ 197.4	$ 2.8	$ 63.5	$ 1.4
Transmission Value of On-site Generation	CB3.2	$ 238.2	$ 3.4	$ 155.9	$ 3.5
Distribution Value of On-site Generation	CB3.3	$ 615.2	$ 8.7	$ 385.3	$ 8.6
Other Retail Bill Components (Trans., EE, RE)	CB3.4	$ 91.0	$ 1.3	$ 56.9	$ 1.3
Offsetting On-site Usage	CB4.1	$ 52.7	$ 0.7	$ 52.6	$ 1.2
Virtual NM	CB4.2	$ 1,668.0	$ 23.7	$ 1,663.5	$ 37.2
Total		**$ 7,702.9**	**$ 109.4**	**$ 6,451.3**	**$ 144.3**

(16)

NPR Costs and Benefits – Policy A Uncapped

Benefits

C/B Component ↓	CB Code	2500 MW NPV Benefits (Million $)	2500 MW NPV $/MWh Benefits	1600 MW NPV Benefits (Million $)	1600 MW NPV $/MWh Benefits
MA Income Taxes	CB1.6.b	$ 247.6	$ 3.5	$ 134.7	$ 3.0
Displaced RPS Class I Compliance Costs	CB2.3	$ 1,515.0	$ 21.5	$ 949.6	$ 21.3
Generation Value of On-site Generation	CB3.1	$ 77.8	$ 1.1	$ 49.4	$ 1.1
Wholesale Market Sales	CB4.3	$ -	$ -	$ -	$ -
Wholesale Market Price Impacts - Energy	CB5.1	$ 54.4	$ 0.8	$ 64.4	$ 1.4
Avoided Generation Capacity Costs	CB5.3	$ 2,101.6	$ 29.9	$ 1,551.2	$ 34.7
Avoided Transmission Tariff Charges	CB5.5	$ 172.3	$ 2.5	$ 148.2	$ 3.3
Avoided Trans. Investment - Remote Wind	CB6.1	$ 181.8	$ 2.6	$ 112.5	$ 2.5
Avoided Transmission Investment - Local	CB6.2	$ 106.9	$ 1.5	$ 90.5	$ 2.0
Avoided Distribution Investment	CB6.3	$ 242.3	$ 3.4	$ 205.1	$ 4.6
Avoided Environmental Impacts	CB7.1	$ 710.8	$ 10.1	$ 660.0	$ 14.8
Total		**$ 5,410.4**	**$ 76.9**	**$ 3,965.6**	**$ 88.8**

Costs

C/B Component ↓	CB Code	2500 MW NPV Costs (Million $)	2500 MW NPV$/MWh Costs	1600 MW NPV Costs (Million $)	1600 MW NPV $/MWh Costs
MA Residential RE Tax Credit	CB1.6.a	$ 58.8	$ 0.8	$ 43.2	$ 1.0
Direct Incentives (e.g., SRECs)	CB2.1	$ 4,080.3	$ 58.0	$ 3,696.4	$ 82.8
Other Solar Policy Compliance Costs (e.g. SACP)	CB2.2	$ 191.7	$ 2.7	$ 191.7	$ 4.3
Solar Policy Incr. Admin. & Transaction Costs	CB2.4	$ 108.1	$ 1.5	$ 61.8	$ 1.4
Transmission Value of On-site Generation	CB3.2	$ 201.9	$ 2.9	$ 148.0	$ 3.3
Distribution Value of On-site Generation	CB3.3	$ 500.3	$ 7.1	$ 360.4	$ 8.1
Other Retail Bill Components (Trans., EE, RE)	CB3.4	$ 81.3	$ 1.2	$ 54.1	$ 1.2
Offsetting On-site Usage	CB4.1	$ 52.9	$ 0.8	$ 52.7	$ 1.2
Virtual NM	CB4.2	$ 1,652.6	$ 23.5	$ 1,648.1	$ 36.9
Total		**$ 6,927.9**	**$ 98.5**	**$ 6,256.5**	**$ 140.1**

(17)

NPR Costs and Benefits – Policy B Capped

Benefits

C/B Component ↓	CB Code	2500 MW NPV Benefits (Million $)	2500 MW NPV $/MWh Benefits	1600 MW NPV Benefits (Million $)	1600 MW NPV $/MWh Benefits
MA Income Taxes	CB1.6.b	$ 251.7	$ 3.6	$ 169.7	$ 3.8
Displaced RPS Class I Compliance Costs	CB2.3	$ 1,555.7	$ 22.1	$ 960.7	$ 21.5
Generation Value of On-site Generation	CB3.1	$ 90.9	$ 1.3	$ 51.9	$ 1.2
Wholesale Market Sales	CB4.3	$ 46.8	$ 0.7	$ 13.1	$ 0.3
Wholesale Market Price Impacts - Energy	CB5.1	$ 54.4	$ 0.8	$ 64.4	$ 1.4
Avoided Generation Capacity Costs	CB5.3	$ 2,100.5	$ 29.8	$ 1,552.8	$ 34.7
Avoided Transmission Tariff Charges	CB5.5	$ 172.2	$ 2.4	$ 148.6	$ 3.3
Avoided Trans. Investment - Remote Wind	CB6.1	$ 181.8	$ 2.6	$ 112.5	$ 2.5
Avoided Transmission Investment - Local	CB6.2	$ 107.1	$ 1.5	$ 90.8	$ 2.0
Avoided Distribution Investment	CB6.3	$ 242.8	$ 3.4	$ 205.8	$ 4.6
Avoided Environmental Impacts	CB7.1	$ 710.8	$ 10.1	$ 660.0	$ 14.8
Total		**$ 5,514.8**	**$ 78.3**	**$ 4,030.4**	**$ 90.2**

Costs

C/B Component ↓	CB Code	2500 MW NPV Costs (Million $)	2500 MW NPV$/MWh Costs	1600 MW NPV Costs (Million $)	1600 MW NPV $/MWh Costs
MA Residential RE Tax Credit	CB1.6.a	$ 60.0	$ 0.9	$ 43.8	$ 1.0
Direct Incentives (e.g., SRECs)	CB2.1	$ 4,419.7	$ 62.7	$ 3,824.0	$ 85.5
Other Solar Policy Compliance Costs (e.g. SACP)	CB2.2	$ 191.1	$ 2.7	$ 191.1	$ 4.3
Solar Policy Incr. Admin. & Transaction Costs	CB2.4	$ 85.3	$ 1.2	$ 30.3	$ 0.7
Transmission Value of On-site Generation	CB3.2	$ 254.0	$ 3.6	$ 156.0	$ 3.5
Distribution Value of On-site Generation	CB3.3	$ 641.9	$ 9.1	$ 386.0	$ 8.6
Other Retail Bill Components (Trans., EE, RE)	CB3.4	$ 91.6	$ 1.3	$ 56.2	$ 1.3
Offsetting On-site Usage	CB4.1	$ 76.9	$ 1.1	$ 58.8	$ 1.3
Virtual NM	CB4.2	$ 1,668.0	$ 23.7	$ 1,663.5	$ 37.2
Total		**$ 7,488.5**	**$ 106.3**	**$ 6,409.7**	**$ 143.4**

(18)

NPR Costs and Benefits – Policy B Uncapped

Benefits

C/B Component ↓	CB Code	2500 MW NPV Benefits (Million $)	2500 MW NPV $/MWh Benefits	1600 MW NPV Benefits (Million $)	1600 MW NPV $/MWh Benefits
MA Income Taxes	CB1.6.b	$ 282.3	$ 4.0	$ 144.9	$ 3.2
Displaced RPS Class I Compliance Costs	CB2.3	$ 1,520.2	$ 21.6	$ 950.2	$ 21.3
Generation Value of On-site Generation	CB3.1	$ 78.7	$ 1.1	$ 49.4	$ 1.1
Wholesale Market Sales	CB4.3	$ -	$ -	$ -	$ -
Wholesale Market Price Impacts - Energy	CB5.1	$ 54.4	$ 0.8	$ 64.4	$ 1.4
Avoided Generation Capacity Costs	CB5.3	$ 2,100.7	$ 29.9	$ 1,551.3	$ 34.7
Avoided Transmission Tariff Charges	CB5.5	$ 172.2	$ 2.4	$ 148.3	$ 3.3
Avoided Trans. Investment - Remote Wind	CB6.1	$ 181.8	$ 2.6	$ 112.5	$ 2.5
Avoided Transmission Investment - Local	CB6.2	$ 106.9	$ 1.5	$ 90.6	$ 2.0
Avoided Distribution Investment	CB6.3	$ 242.2	$ 3.4	$ 205.3	$ 4.6
Avoided Environmental Impacts	CB7.1	$ 710.8	$ 10.1	$ 660.0	$ 14.8
Total		**$ 5,450.2**	**$ 77.5**	**$ 3,977.0**	**$ 89.1**

Costs

C/B Component ↓	CB Code	2500 MW NPV Costs (Million $)	2500 MW NPV$/MWh Costs	1600 MW NPV Costs (Million $)	1600 MW NPV $/MWh Costs
MA Residential RE Tax Credit	CB1.6.a	$ 59.1	$ 0.8	$ 43.4	$ 1.0
Direct Incentives (e.g., SRECs)	CB2.1	$ 3,668.6	$ 52.2	$ 3,599.4	$ 80.6
Other Solar Policy Compliance Costs (e.g. SACP)	CB2.2	$ 191.7	$ 2.7	$ 191.7	$ 4.3
Solar Policy Incr. Admin. & Transaction Costs	CB2.4	$ 85.1	$ 1.2	$ 30.2	$ 0.7
Transmission Value of On-site Generation	CB3.2	$ 225.6	$ 3.2	$ 148.4	$ 3.3
Distribution Value of On-site Generation	CB3.3	$ 544.3	$ 7.7	$ 362.7	$ 8.1
Other Retail Bill Components (Trans., EE, RE)	CB3.4	$ 81.5	$ 1.2	$ 54.0	$ 1.2
Offsetting On-site Usage	CB4.1	$ 90.0	$ 1.3	$ 61.4	$ 1.4
Virtual NM	CB4.2	$ 2,742.0	$ 39.0	$ 1,885.7	$ 42.2
Total		**$ 7,687.9**	**$ 109.3**	**$ 6,376.9**	**$ 142.8**

(19)

C@L Costs and Benefits – SREC Capped

Benefits

C/B Component ↓	CB Code	2500 MW NPV Benefits (Million $)	2500 MW NPV $/MWh Benefits	1600 MW NPV Benefits (Million $)	1600 MW NPV $/MWh Benefits
System Installed Costs	CB1.1	$ 2,812.6	$ 40.8	$ 2,176.9	$ 50.0
Ongoing O&M + Insurance Costs	CB1.2	$ 884.9	$ 12.8	$ 627.4	$ 14.4
Lease Payments	CB1.3	$ 228.2	$ 3.3	$ 209.0	$ 4.8
PILOTs / Property Taxes	CB1.4	$ 152.6	$ 2.2	$ 148.1	$ 3.4
ROI (Aggregate Return to Debt & Equity)	CB1.5	$ 1,120.9	$ 16.3	$ 667.7	$ 15.3
Federal Incentives (ITC)	CB1.7a	$ 195.7	$ 2.8	$ 188.8	$ 4.3
Displaced RPS Class I Compliance Costs	CB2.3	$ 1,471.6	$ 21.4	$ 921.8	$ 21.2
Generation Value of On-site Generation	CB3.1	$ 2,554.3	$ 37.1	$ 1,102.4	$ 25.3
Other Retail Bill Components (Trans., EE, RE)	CB3.4	$ 14.2	$ 0.2	$ 6.8	$ 0.2
Offsetting On-site Usage	CB4.1	$ 157.0	$ 2.3	$ 62.9	$ 1.4
Virtual NM	CB4.2	$ 1,282.7	$ 18.6	$ 1,287.7	$ 29.6
Wholesale Market Sales	CB4.3	$ 72.9	$ 1.1	$ 51.1	$ 1.2
Wholesale Market Price Impacts - Energy	CB5.1	$ 54.4	$ 0.8	$ 64.4	$ 1.5
Avoided Generation Capacity Costs	CB5.3	$ 2,184.5	$ 31.7	$ 1,629.0	$ 37.4
Avoided Transmission Tariff Charges	CB5.5	$ 167.0	$ 2.4	$ 148.4	$ 3.4
Avoided Trans. Investment - Remote Wind	CB6.1	$ 181.8	$ 2.6	$ 112.5	$ 2.6
Avoided Transmission Investment - Local	CB6.2	$ 102.5	$ 1.5	$ 88.6	$ 2.0
Avoided Distribution Investment	CB6.3	$ 232.4	$ 3.4	$ 200.9	$ 4.6
Avoided Environmental Impacts	CB7.1	$ 710.8	$ 10.3	$ 660.0	$ 15.1
Total		**$ 14,581.0**	**$ 211.7**	**$ 10,354.3**	**$ 237.6**

Costs

C/B Component ↓	CB Code	2500 MW NPV Costs (Million $)	2500 MW NPV$/MWh Costs	1600 MW NPV Costs (Million $)	1600 MW NPV $/MWh Costs
Federal Income Taxes	CB1.7b	$ 642.5	$ 9.3	$ 656.5	$ 15.1
Direct Incentives (e.g., SRECs)	CB2.1	$ 4,884.4	$ 70.9	$ 3,871.4	$ 88.8
Solar Policy Incr. Admin. & Transaction Costs	CB2.4	$ -	$ -	$ -	$ -
Total		**$ 5,526.9**	**$ 80.2**	**$ 4,528.0**	**$ 103.9**

(20)

C@L Costs and Benefits – SREC Uncapped

Benefits

C/B Component ↓	CB Code	1600 MW NPV Benefits (Million $)	1600 MW NPV $/MWh Benefits
System Installed Costs	CB1.1	$ 2,157.3	$ 49.6
Ongoing O&M + Insurance Costs	CB1.2	$ 631.5	$ 14.5
Lease Payments	CB1.3	$ 223.4	$ 5.1
PILOTs / Property Taxes	CB1.4	$ 160.7	$ 3.7
ROI (Aggregate Return to Debt & Equity)	CB1.5	$ 761.2	$ 17.5
Federal Incentives (ITC)	CB1.7a	$ 188.7	$ 4.3
Displaced RPS Class I Compliance Costs	CB2.3	$ 893.5	$ 20.5
Generation Value of On-site Generation	CB3.1	$ 908.1	$ 20.9
Other Retail Bill Components (Trans., EE, RE)	CB3.4	$ 5.8	$ 0.1
Offsetting On-site Usage	CB4.1	$ 51.9	$ 1.2
Virtual NM	CB4.2	$ 1,496.4	$ 34.4
Wholesale Market Sales	CB4.3	$ -	$ -
Wholesale Market Price Impacts - Energy	CB5.1	$ 64.4	$ 1.5
Avoided Generation Capacity Costs	CB5.3	$ 1,627.1	$ 37.4
Avoided Transmission Tariff Charges	CB5.5	$ 148.2	$ 3.4
Avoided Trans. Investment - Remote Wind	CB6.1	$ 112.5	$ 2.6
Avoided Transmission Investment - Local	CB6.2		
Avoided Distribution Investment	CB6.3		
Avoided Environmental Impacts	CB7.1	$ 660.0	$ 15.2
Total		**$ 10,090.7**	**$ 231.8**

Costs

C/B Component ↓	CB Code	1600 MW NPV Costs (Million $)	1600 MW NPV $/MWh Costs
Federal Income Taxes	CB1.7b	$ 332.8	$ 7.6
Direct Incentives (e.g., SRECs)	CB2.1	$ 3,812.7	$ 87.6
Solar Policy Incr. Admin. & Transaction Costs	CB2.4	$ -	$ -
Total		**$ 4,145.4**	**$ 95.2**

(21)

C@L Costs and Benefits – Policy A Capped

Benefits

C/B Component ↓	CB Code	2500 MW NPV Benefits (Million $)	2500 MW NPV $/MWh Benefits	1600 MW NPV Benefits (Million $)	1600 MW NPV $/MWh Benefits
System Installed Costs	CB1.1	$ 2,632.4	$ 37.4	$ 2,139.6	$ 47.9
Ongoing O&M + Insurance Costs	CB1.2	$ 813.2	$ 11.5	$ 607.7	$ 13.6
Lease Payments	CB1.3	$ 304.3	$ 4.3	$ 222.7	$ 5.0
PILOTs / Property Taxes	CB1.4	$ 204.3	$ 2.9	$ 156.8	$ 3.5
ROI (Aggregate Return to Debt & Equity)	CB1.5	$ 668.3	$ 9.5	$ 590.2	$ 13.2
Federal Incentives (ITC)	CB1.7a	$ 200.3	$ 2.8	$ 187.7	$ 4.2
Displaced RPS Class I Compliance Costs	CB2.3	$ 1,552.6	$ 22.0	$ 961.4	$ 21.5
Generation Value of On-site Generation	CB3.1	$ 1,721.8	$ 24.4	$ 993.7	$ 22.2
Other Retail Bill Components (Trans., EE, RE)	CB3.4	$ 10.1	$ 0.1	$ 6.3	$ 0.1
Offsetting On-site Usage	CB4.1	$ 71.6	$ 1.0	$ 51.3	$ 1.1
Virtual NM	CB4.2	$ 1,194.8	$ 17.0	$ 1,199.3	$ 26.8
Wholesale Market Sales	CB4.3	$ 888.1	$ 12.6	$ 239.3	$ 5.4
Wholesale Market Price Impacts - Energy	CB5.1	$ 54.4	$ 0.8	$ 64.4	$ 1.4
Avoided Generation Capacity Costs	CB5.3	$ 2,222.3	$ 31.5	$ 1,630.4	$ 36.5
Avoided Transmission Tariff Charges	CB5.5	$ 172.6	$ 2.4	$ 148.4	$ 3.3
Avoided Trans. Investment - Remote Wind	CB6.1	$ 181.8	$ 2.6	$ 112.5	$ 2.5
Avoided Transmission Investment - Local	CB6.2	$ 107.3	$ 1.5	$ 90.7	$ 2.0
Avoided Distribution Investment	CB6.3	$ 243.2	$ 3.5	$ 205.6	$ 4.6
Avoided Environmental Impacts	CB7.1	$ 710.8	$ 10.1	$ 660.0	$ 14.8
Total		**$ 13,954.3**	**$ 198.1**	**$ 10,268.0**	**$ 229.7**

Costs

C/B Component ↓	CB Code	2500 MW NPV Costs (Million $)	2500 MW NPV$/MWh Costs	1600 MW NPV Costs (Million $)	1600 MW NPV $/MWh Costs
Federal Income Taxes	CB1.7b	$ 1,249.0	$ 17.7	$ 765.6	$ 17.1
Direct Incentives (e.g., SRECs)	CB2.1	$ 4,589.4	$ 65.2	$ 3,838.8	$ 85.9
Solar Policy Incr. Admin. & Transaction Costs	CB2.4	$ 197.4	$ 2.8	$ 63.5	$ 1.4
Total		**$ 6,035.8**	**$ 85.7**	**$ 4,667.9**	**$ 104.4**

(22)

C@L Costs and Benefits – Policy A Uncapped

Benefits

C/B Component ↓	CB Code	2500 MW NPV Benefits (Million $)	2500 MW NPV $/MWh Benefits	1600 MW NPV Benefits (Million $)	1600 MW NPV $/MWh Benefits
System Installed Costs	CB1.1	$ 2,619.5	$ 37.3	$ 2,135.9	$ 47.8
Ongoing O&M + Insurance Costs	CB1.2	$ 562.7	$ 8.0	$ 550.2	$ 12.3
Lease Payments	CB1.3	$ 203.8	$ 2.9	$ 198.1	$ 4.4
PILOTs / Property Taxes	CB1.4	$ 146.8	$ 2.1	$ 142.9	$ 3.2
ROI (Aggregate Return to Debt & Equity)	CB1.5	$ 688.7	$ 9.8	$ 641.8	$ 14.4
Federal Incentives (ITC)	CB1.7a	$ 200.6	$ 2.9	$ 188.5	$ 4.2
Displaced RPS Class I Compliance Costs	CB2.3	$ 1,515.0	$ 21.5	$ 949.6	$ 21.3
Generation Value of On-site Generation	CB3.1	$ 1,471.1	$ 20.9	$ 933.1	$ 20.9
Other Retail Bill Components (Trans., EE, RE)	CB3.4	$ 9.0	$ 0.1	$ 6.0	$ 0.1
Offsetting On-site Usage	CB4.1	$ 92.3	$ 1.3	$ 55.6	$ 1.2
Virtual NM	CB4.2	$ 2,519.7	$ 35.8	$ 1,537.1	$ 34.4
Wholesale Market Sales	CB4.3	$ -	$ -	$ -	$ -
Wholesale Market Price Impacts - Energy	CB5.1	$ 54.4	$ 0.8	$ 64.4	$ 1.4
Avoided Generation Capacity Costs	CB5.3	$ 2,220.7	$ 31.6	$ 1,629.0	$ 36.5
Avoided Transmission Tariff Charges	CB5.5	$ 172.3	$ 2.5	$ 148.2	$ 3.3
Avoided Trans. Investment - Remote Wind	CB6.1	$ 181.8	$ 2.6	$ 112.5	$ 2.5
Avoided Transmission Investment - Local	CB6.2	$ 106.9	$ 1.5	$ 90.5	$ 2.0
Avoided Distribution Investment	CB6.3	$ 242.3	$ 3.4	$ 205.1	$ 4.6
Avoided Environmental Impacts	CB7.1	$ 710.8	$ 10.1	$ 660.0	$ 14.8
Total		**$ 13,718.3**	**$ 195.1**	**$ 10,248.4**	**$ 229.5**

Costs

C/B Component ↓	CB Code	2500 MW NPV Costs (Million $)	2500 MW NPV$/MWh Costs	1600 MW NPV Costs (Million $)	1600 MW NPV $/MWh Costs
Federal Income Taxes	CB1.7b	$ 1,083.1	$ 15.4	$ 589.3	$ 13.2
Direct Incentives (e.g., SRECs)	CB2.1	$ 4,080.3	$ 58.0	$ 3,696.4	$ 82.8
Solar Policy Incr. Admin. & Transaction Costs	CB2.4	$ 108.1	$ 1.5	$ 61.8	$ 1.4
Total		**$ 5,271.6**	**$ 75.0**	**$ 4,347.5**	**$ 97.3**

(23)

C@L Costs and Benefits – Policy B Capped

Benefits

C/B Component ↓	CB Code	2500 MW NPV Benefits (Million $)	2500 MW NPV $/MWh Benefits	1600 MW NPV Benefits (Million $)	1600 MW NPV $/MWh Benefits
System Installed Costs	CB1.1	$ 2,614.3	$ 37.1	$ 2,136.2	$ 47.8
Ongoing O&M + Insurance Costs	CB1.2	$ 841.7	$ 11.9	$ 617.5	$ 13.8
Lease Payments	CB1.3	$ 299.1	$ 4.2	$ 222.4	$ 5.0
PILOTs / Property Taxes	CB1.4	$ 204.3	$ 2.9	$ 157.5	$ 3.5
ROI (Aggregate Return to Debt & Equity)	CB1.5	$ 708.6	$ 10.1	$ 599.4	$ 13.4
Federal Incentives (ITC)	CB1.7a	$ 198.9	$ 2.8	$ 187.3	$ 4.2
Displaced RPS Class I Compliance Costs	CB2.3	$ 1,555.7	$ 22.1	$ 960.7	$ 21.5
Generation Value of On-site Generation	CB3.1	$ 1,719.3	$ 24.4	$ 981.1	$ 21.9
Other Retail Bill Components (Trans., EE, RE)	CB3.4	$ 9.9	$ 0.1	$ 6.3	$ 0.1
Offsetting On-site Usage	CB4.1	$ 65.9	$ 0.9	$ 49.9	$ 1.1
Virtual NM	CB4.2	$ 1,194.8	$ 17.0	$ 1,199.3	$ 26.8
Wholesale Market Sales	CB4.3	$ 885.5	$ 12.6	$ 248.0	$ 5.5
Wholesale Market Price Impacts - Energy	CB5.1	$ 54.4	$ 0.8	$ 64.4	$ 1.4
Avoided Generation Capacity Costs	CB5.3	$ 2,219.7	$ 31.5	$ 1,630.6	$ 36.5
Avoided Transmission Tariff Charges	CB5.5	$ 172.2	$ 2.4	$ 148.6	$ 3.3
Avoided Trans. Investment - Remote Wind	CB6.1	$ 181.8	$ 2.6	$ 112.5	$ 2.5
Avoided Transmission Investment - Local	CB6.2	$ 107.1	$ 1.5	$ 90.8	$ 2.0
Avoided Distribution Investment	CB6.3	$ 242.8	$ 3.4	$ 205.8	$ 4.6
Avoided Environmental Impacts	CB7.1	$ 710.8	$ 10.1	$ 660.0	$ 14.8
Total		**$ 13,986.6**	**$ 198.6**	**$ 10,278.3**	**$ 229.9**

Costs

C/B Component ↓	CB Code	2500 MW NPV Costs (Million $)	2500 MW NPV$/MWh Costs	1600 MW NPV Costs (Million $)	1600 MW NPV $/MWh Costs
Federal Income Taxes	CB1.7b	$ 1,101.2	$ 15.6	$ 736.4	$ 16.5
Direct Incentives (e.g., SRECs)	CB2.1	$ 4,419.7	$ 62.7	$ 3,824.0	$ 85.5
Solar Policy Incr. Admin. & Transaction Costs	CB2.4	$ 85.3	$ 1.2	$ 30.3	$ 0.7
Total		**$ 5,606.2**	**$ 79.6**	**$ 4,590.7**	**$ 102.7**

(24)

C@L Costs and Benefits – Policy B Uncapped

Benefits

C/B Component ↓	CB Code	2500 MW NPV Benefits (Million $)	2500 MW NPV $/MWh Benefits	1600 MW NPV Benefits (Million $)	1600 MW NPV $/MWh Benefits
System Installed Costs	CB1.1	$ 2,635.2	$ 37.5	$ 2,140.3	$ 47.9
Ongoing O&M + Insurance Costs	CB1.2	$ 873.8	$ 12.4	$ 624.7	$ 14.0
Lease Payments	CB1.3	$ 299.1	$ 4.3	$ 222.0	$ 5.0
PILOTs / Property Taxes	CB1.4	$ 213.2	$ 3.0	$ 159.5	$ 3.6
ROI (Aggregate Return to Debt & Equity)	CB1.5	$ 575.7	$ 8.2	$ 651.0	$ 14.6
Federal Incentives (ITC)	CB1.7a	$ 200.2	$ 2.8	$ 188.4	$ 4.2
Displaced RPS Class I Compliance Costs	CB2.3	$ 1,520.2	$ 21.6	$ 950.2	$ 21.3
Generation Value of On-site Generation	CB3.1	$ 1,488.6	$ 21.2	$ 934.5	$ 20.9
Other Retail Bill Components (Trans., EE, RE)	CB3.4	$ 8.7	$ 0.1	$ 6.0	$ 0.1
Offsetting On-site Usage	CB4.1	$ 82.6	$ 1.2	$ 53.4	$ 1.2
Virtual NM	CB4.2	$ 2,231.3	$ 31.7	$ 1,476.7	$ 33.1
Wholesale Market Sales	CB4.3	$ -	$ -	$ -	$ -
Wholesale Market Price Impacts - Energy	CB5.1	$ 54.4	$ 0.8	$ 64.4	$ 1.4
Avoided Generation Capacity Costs	CB5.3	$ 2,220.0	$ 31.6	$ 1,629.2	$ 36.5
Avoided Transmission Tariff Charges	CB5.5	$ 172.2	$ 2.4	$ 148.3	$ 3.3
Avoided Trans. Investment - Remote Wind	CB6.1	$ 181.8	$ 2.6	$ 112.5	$ 2.5
Avoided Transmission Investment - Local	CB6.2	$ 106.9	$ 1.5	$ 90.6	$ 2.0
Avoided Distribution Investment	CB6.3	$ 242.2	$ 3.4	$ 205.3	$ 4.6
Avoided Environmental Impacts	CB7.1	$ 710.8	$ 10.1	$ 660.0	$ 14.8
Total		**$ 13,816.7**	**$ 196.5**	**$ 10,317.0**	**$ 231.0**

Costs

C/B Component ↓	CB Code	2500 MW NPV Costs (Million $)	2500 MW NPV$/MWh Costs	1600 MW NPV Costs (Million $)	1600 MW NPV $/MWh Costs
Federal Income Taxes	CB1.7b	$ 1,235.2	$ 17.6	$ 634.0	$ 14.2
Direct Incentives (e.g., SRECs)	CB2.1	$ 3,668.6	$ 52.2	$ 3,599.4	$ 80.6
Solar Policy Incr. Admin. & Transaction Costs	CB2.4	$ 85.1	$ 1.2	$ 30.2	$ 0.7
Total		**$ 4,989.0**	**$ 71.0**	**$ 4,263.7**	**$ 95.5**

Task 3 Report: Appendix C

Appendix C:

Task 3 - Analysis of Costs and Benefits: Policy Paths A & B Modeled Incentives

Massachusetts Net Metering and Solar Task Force

PEREGRINE ENERGY GROUP

Sustainable Energy Advantage, LLC

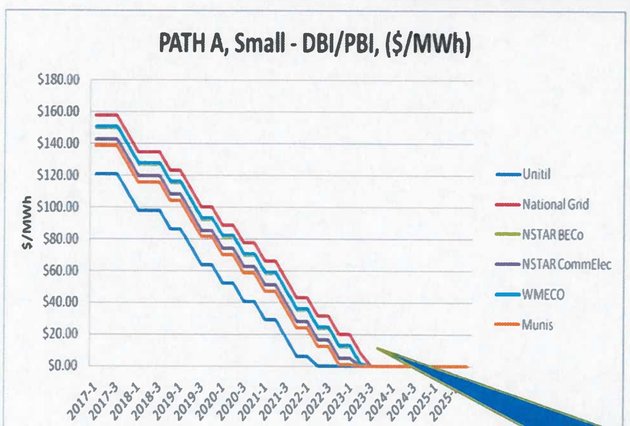
MEISTER CONSULTANTS GROUP

La Capra Associates

Policy Path A – Small Residential DBI/PBI

Slightly different DBI clearing speed function of slightly different starting tech. potential (**extremely** marginal effect)

Capped



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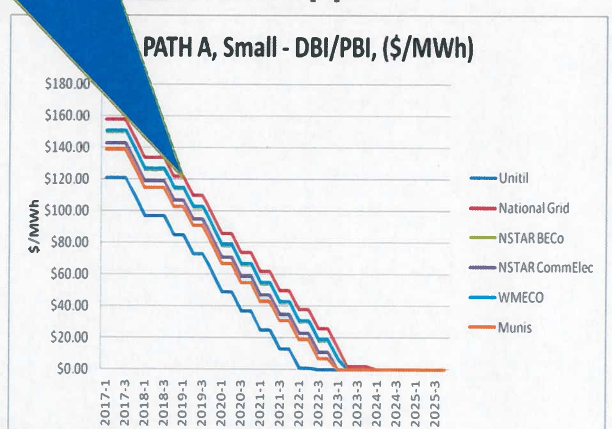


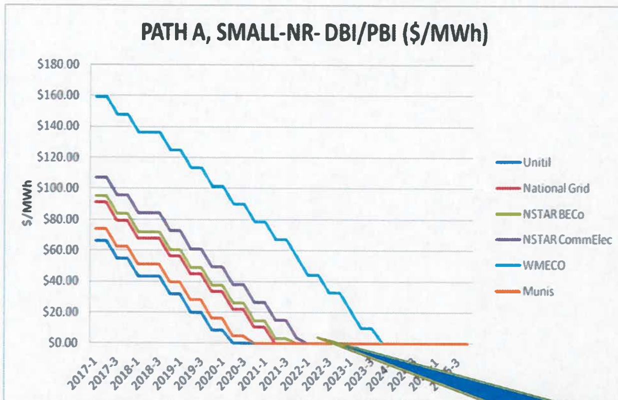
No PBI incentive needed Post-2023-Q2

(2)

Policy Path A – Small Non-Residential DBI/PBI

Slightly different DBI clearing speed function of slightly different starting tech. potential (**extremely** marginal effect)

Capped



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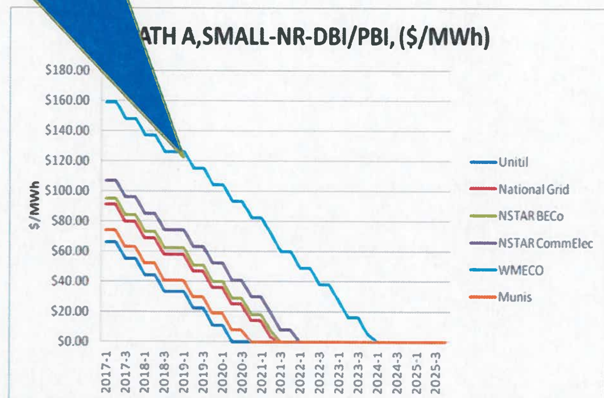

No PBI incentive needed Post-2021

(3)

Policy Path A – Large Competitive PBI – Sector A

When lines cross, Sector A which is dominated by CSS and VNM LIH do not need PBI with VNM.

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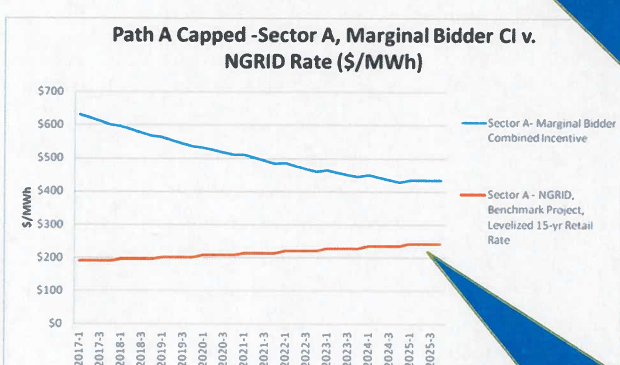

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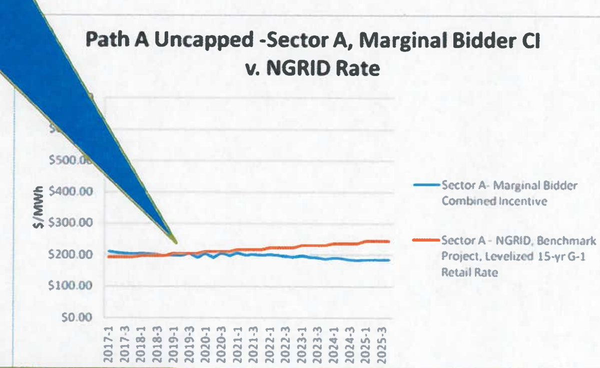

Marginal bid moves to convergence with rates, all Sectors.

(4)

Policy Path A – Large Competitive PBI – Sector B

Spikes reflect supply lumpiness and modeling method.

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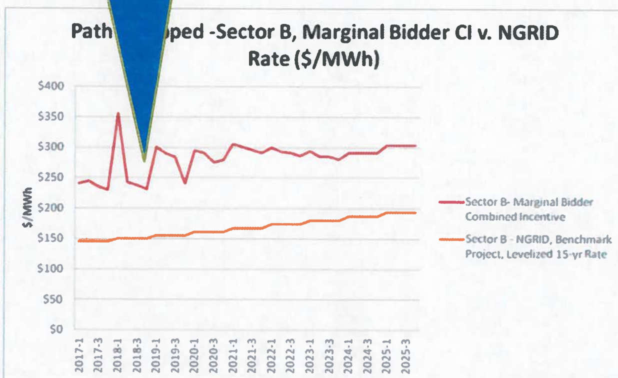

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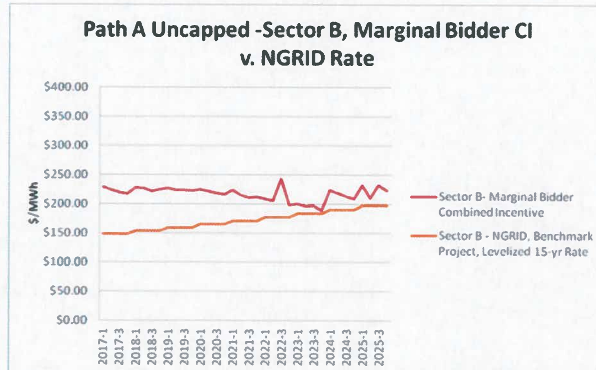
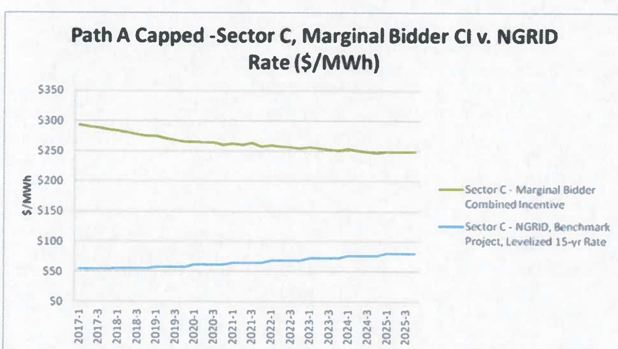


(5)

Policy Path A – Large Competitive PBI – Sector C

Higher Marginal Bid is function of modeling constraints, and not likely to be seen in practice. See Note.

Capped



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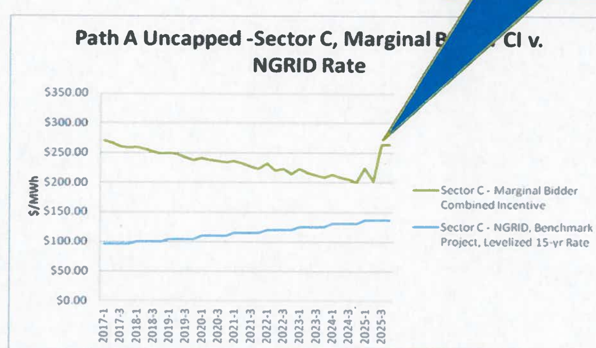

(6)

Policy Path A – Large Competitive PBI – Sector D

Spikes are reflective of "Price is Right" Modeling Assumption

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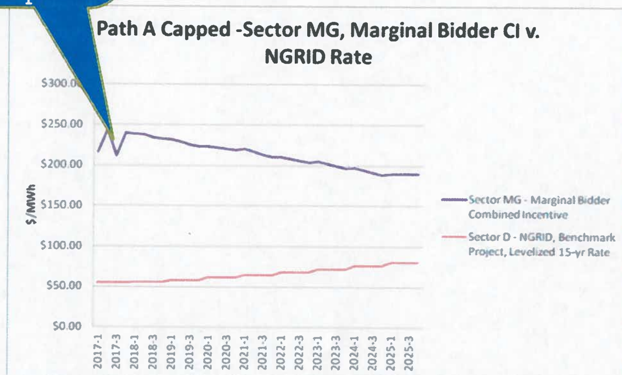

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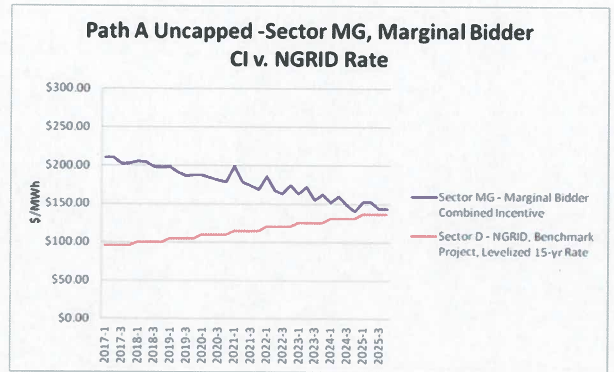

(7)

Policy Path B – Small Residential DBI/EPBI

Same for Both NM/ no NM

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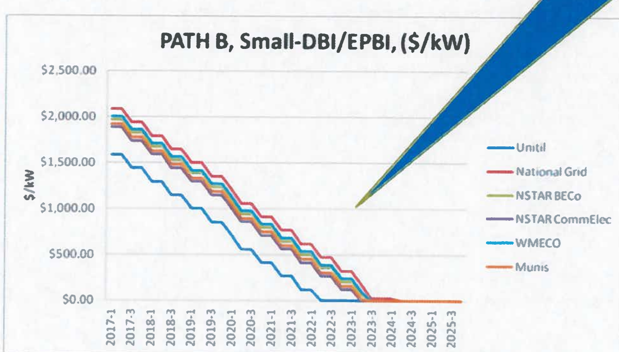

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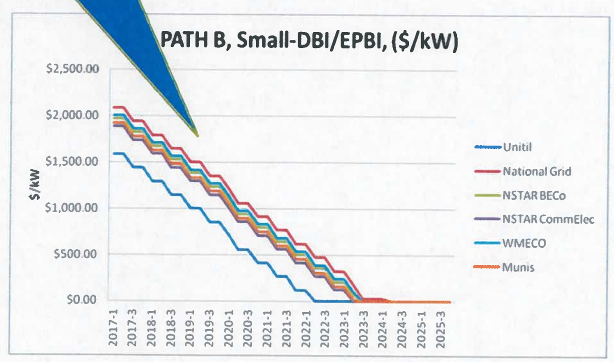

(8)

Policy Path B – Small Non-Residential DBI/EPBI

Same for Both NM/ no NM

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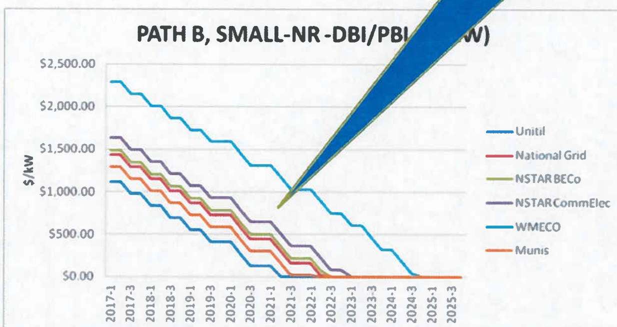

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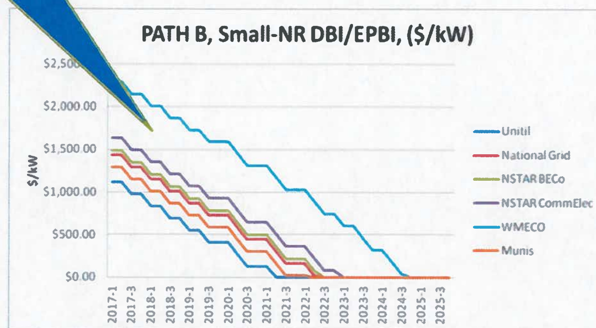

(9)

Policy Path B – Sector A DBI/PBI

By 2019, CSS and VNM LIH are no longer dependent on PBI at current NM levels

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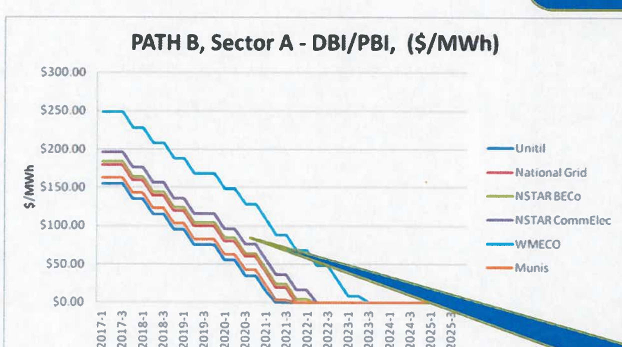

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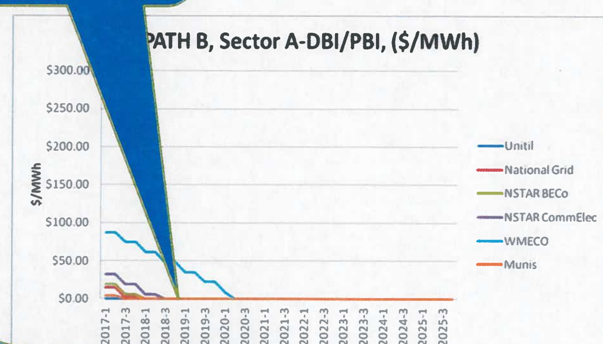

Comparative PBI levels must be viewed in context of lowered target (25%-10%)

(10)

Policy Path B – Sector B DBI/PBI

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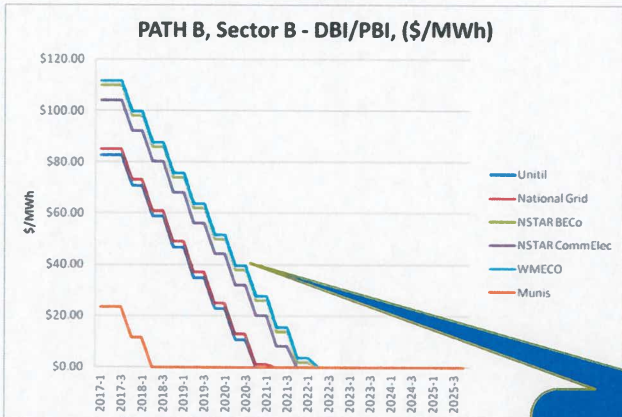

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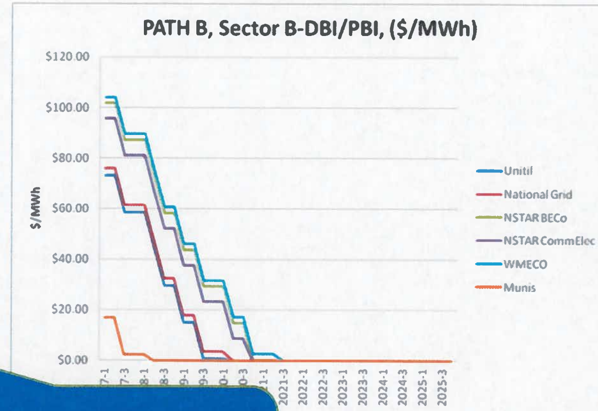


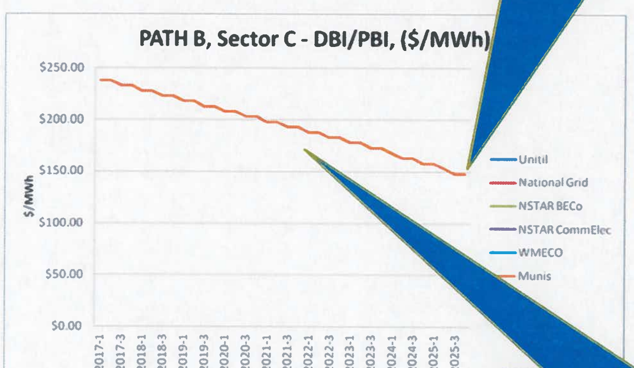
Comparative PBI levels must be viewed in context of raised target (25%-30%)

(11)

Policy Path B – Sector C DBI/PBI

Without NM retail rate is QF wholesale rate which is assumed equal across utility territories

Capped



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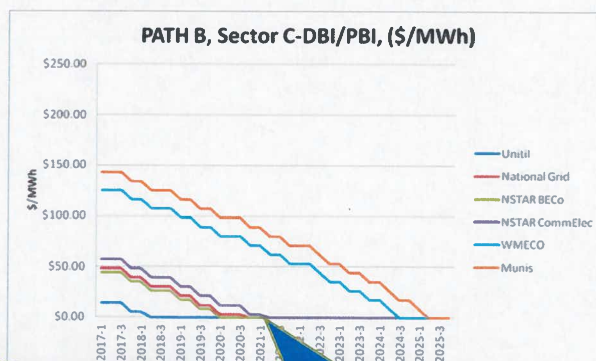


Comparative PBI levels must be viewed in context of raised target (25%-30%)

Most growth post-2020 is NM rate driven; signals no need for PBI after 2021

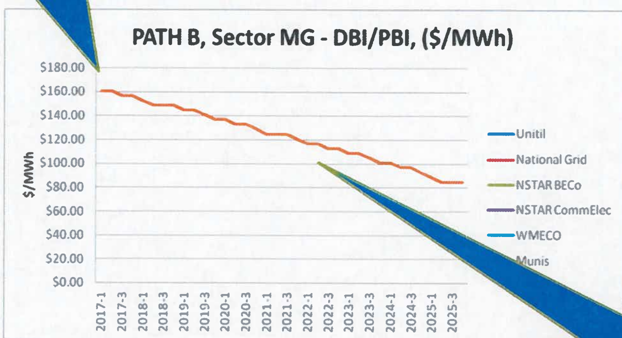
(12)

Policy Path B – Sector MG DBI/PBI

Without NM retail rate is QF wholesale rate which is assumed equal across utility territories

Most growth post 2021 is NM Rate Driven

Capped



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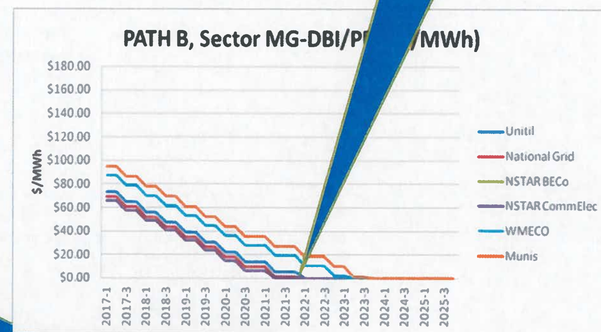


Comparative PBI levels must be viewed in context of raised target (25%-30%)

(13)

APPENDIX D: COMPONENTS OF COST/BENEFIT ANALYSIS

As noted in Section 1, this study is intended to explore the relative, in tandem with the overall, costs and benefits associated with net energy metering. As noted in the final Task Force Framing Memorandum,

The language in the legislation regarding "costs and benefits" is not intended for us to evaluate the costs and benefits of achieving this 1600 MW goal, but directs ***us to consider the relative costs and benefits of policy options to achieve the goal****, as well as the overall cost and benefits of the existing net metering framework from the perspective of multiple customer groups.*

More specifically, this analysis illustrates how these costs and benefits compare, in both relative and overall terms, across different alternative policy futures, from the four cost-benefit perspectives (non-owner participant, customer-generator, non-participating ratepayers, and citizens of Massachusetts at large) described in Section 1.2.

D.1 Overview of Cost Benefit Categories and Subcategories

The cost and benefit framework addresses seven broad categories of costs and benefits. These seven categories can be subdivided into two groups, as follows:

D.1.1 Ratepayer & Participant Costs and Benefits

Ratepayer and participant cost and benefit impacts experienced directly include those incurred and accruing to both participants and non-participants in solar and net energy metering policies. They fall into four categories as follows:

- **Solar PV System Costs**: The direct costs associated with PV systems;
- **Solar Policy**: Massachusetts' (and Federal) public policies and programs related to renewable energy and solar PV;
- **Behind-the-Meter (BTM) Solar Production within a Billing Month**: The on-site and "behind the meter" solar PV production that reduces customer bills during the billing month; and
- **Net Metering Credits (NMC, from Net Metering Beyond the Billing Month & Virtual Net Metering (VNM)**: Net metering credits gained by customers as a result of solar PV production exceeding a customer's usage during a given month from an on-site or remote VNM installation.

These costs and benefits will differ significantly across the alternative policy futures explored in this study, particularly given that SREC, Policy Path A and Policy Path B have very different solar PV incentive structures and approaches dealing with net metering credits. In addition, each of these categories has multiple subcategories of costs and benefits, which have a diverse array of impacts on the four cost-benefit perspectives analyzed.

D.1.2 Secondary Costs and Benefits

In addition to the net ratepayer and participant values, solar PV can also cause three broad categories of costs and benefits to accrue broadly to each of the four perspectives on a secondary market and societal basis. Specifically, solar PV can result in secondary impacts to:

- **Electric Market(s)**;
- **Electric Investment Impacts**; and
- **Externalities and Other Impacts**.

These impacts are primarily a function of the amount of solar PV installed in Massachusetts, and therefore will be quite similar across the different scenarios to the extent that they each reach 2500 MW in a similar timeframe. To the degree their values differ, this will be primarily driven by the variation in solar PV deployment between the futures studied.

D.2 Cost and Benefit Components and Level of Analysis

Within each of these categories, there are a number of individual cost and benefit components that comprise the individual impacts to be considered. Table 43 below illustrates the subcategories associated with these three categories of secondary costs and benefits. A color coding of these broad categories by color code and hue is used throughout to aid the reader in following the various components of this complex analysis.

Table 75: Cost and Benefit Categories and Components

Category	Subcategory	Code	Analysis
PV System Costs	System Installed Costs	CB1.1	Quantitative
	Ongoing O&M + Insurance Costs	CB1.2	Quantitative
	Lease Payments	CB1.3	Quantitative
	PILOTs / Property Taxes	CB1.4	Quantitative
	ROI (to lenders & investors)	CB1.5	Quantitative
	MA Residential RE Tax Credit	CB1.6a	Quantitative
	MA Income Taxes	CB1.6b	Quantitative
	Federal Incentives (ITC)	CB1.7a	Quantitative
	Federal Income Taxes	CB1.7b	Quantitative
Solar Policy	Direct Incentives	CB2.1	Quantitative
	Other Solar Policy Compliance Costs	CB2.2	Quantitative
	Displaced RPS Class I Compliance Costs	CB2.3	Quantitative
	Solar Policy Incremental Admin. & Transaction Costs	CB2.4	Quantitative
Behind-the-Meter Production During the Billing Month	Generation Value of On-site Generation	CB3.1	Quantitative
	Transmission Value of On-site Generation	CB3.2	Quantitative
	Distribution Value of On-site Generation	CB3.3	Quantitative
	Other Retail Bill Components (Transition, EE, RE)	CB3.4	Quantitative
Net Metering Credits Beyond the Billing Month	Offsetting On-site Usage	CB4.1	Quantitative
	Virtual NM	CB4.2	Quantitative
	Wholesale Market Sales	CB4.3	Quantitative
	Virtual NM Administrative Costs	CB4.4	*Qualitative*
Electric Markets	Wholesale Market Price Impacts – Energy	CB5.1	Quantitative
	Wholesale Market Price Impacts – Capacity	CB5.2	*Qualitative*
	Avoided Generation Capacity Costs	CB5.3	Quantitative
	Avoided Line Losses	CB5.4	Quantitative
	Avoided Transmission Tariff Charges	CB5.5	Quantitative
Electric Investment Impacts	Avoided Transmission Investment - Remote Wind	CB6.1	Quantitative
	Avoided Transmission Investment – Local	CB6.2	Quantitative
	Avoided Distribution Investment	CB6.3	Quantitative
	Avoided Natural Gas Pipeline	CB6.4	*Qualitative*
Externalities and Other	Avoided Environmental Costs CO_2, NO_x and SO_x	CB7.1	Quantitative
	Avoided Fuel Uncertainty	CB7.2	*Qualitative*
	Resiliency	CB7.3	*Qualitative*
	Impact on Jobs	CB7.4	*Qualitative*
	Policy Transition Frictional Costs	CB7.5	*Qualitative*

Given the scope, tight timelines, limited budget, and other practical limitations, not all of costs and benefits of solar PV are quantified herein. This is the case, in part, because the data needed to undertake a study of this type requires a wide variety of data sources that may or may not be easily or reliably quantified. As a result, this study includes a mix of three types of data:

- **Quantitative** data derived from detailed analysis for the purposes of this study.
- <u>Parametric</u> assumptions that represents an "educated guess" made in order to estimate the impact when quantitative data is difficult to verify or unavailable (later, we run sensitivity analyses on many of these parametric assumptions in order to assess the potential impact of uncertainty for the applicable components); and
- *Qualitative* data and information that represents a generalized assessment of a particular category and/or sub-category of costs and benefits, but not included in the summation of cost of benefit.

Certain major outputs included in more expansive economic analyses that are not fully quantified in this analysis include:

- **Indirect macroeconomic impacts**, which (in this case) include the costs and benefits incurred broadly outside of the solar industry as a result of current policies and alternative policy futures;

- **Induced macroeconomic Impacts**, or the changes in spending, economic behaviors or habits as a result of the direct and indirect costs and benefits.

  - Impacts identified as addressed qualitatively will be discussed in a generalized sense later in this report. Table 43 shows which cost and benefit components are quantified, and which are dealt with qualitatively.

In order to clearly illustrate the "flows" or distribution of costs and benefits associated with each policy future, each component of costs and benefits discussed in this section has a table describing how that cost and benefit category manifests as either a cost or benefit (or both) from each of the four perspectives. These tables also identify whether quantitative or qualitative analysis is performed for this study, and in some instances, whether a parametric assumption is used in estimating a quantified impact; the manner in which it is being used, and whether the result accrues as a benefit, cost, or is not considered to be either from each of the four cost-benefit perspectives. Table 44 below presents a key to understanding when each type of data is being used, and if that result is a cost or benefit to the perspective in question, within the sections that follow.

Table 76: Key to Cost and Benefit Description Tables

Classification	**Benefit**	**Cost**	N/A
Type of Information	**Quantitative (Bold)**	<u>Parametric</u> (Underlined)	*Qualitative* (italics)

D.3 Category 1: PV System Costs

The first major category of costs and benefits considered in this analysis are associated with the cost of grid-tied solar PV systems eligible for net metering. The nine subcategories of costs and benefits contained within PV system costs are as follows

Subcategory	Code	Analysis
System Installed Costs	CB1.1	Quantitative
Ongoing O&M + Insurance Costs	CB1.2	Quantitative
Lease Payments	CB1.3	Quantitative
PILOTs / Property Taxes	CB1.4	Quantitative

ROI (to lenders & investors)	CB1.5	Quantitative
MA Residential RE Tax Credit	CB1.6a	Quantitative
MA Income Taxes	CB1.6b	Quantitative
Federal Incentives (ITC)	CB1.7a	Quantitative
Federal Income Taxes	CB1.7b	Quantitative

For ease of estimation, PV system installed and operating costs are assumed to be independent of the specific state policy futures, primarily driven by global module markets and local scale economies.[106] These costs vary by installation type and in some cases ownership model, but are held constant across alternative policy futures. When calculated installed costs throughout the baseline policy and alternative policy futures, the total costs per year can be stated as:

$$\sum_{ij} kW_{ij} * \$ / kW_i$$

where

i = type of installation; and j = the associated EDC territory.

For operating & maintenance costs, insurance, lease payments, and property taxes, a similar formula s used:

$$\sum_{ij} kW_{ij} * \$ / kWyr_i$$

Table 45 below illustrates how these subcategories accrue as direct costs or benefits to the four perspectives analyzed.

Table 77: PV System Cost Applicability to Analysis Perspectives

Perspec tive	Subcategories Accruing as Benefits to Some or All With Perspective	Subcategories Accruing as Costs to Some or All With Perspective
Non-Owner Participants **(NOP)**	- Lease Payments - PILOTs/Property Taxes	- MA and Federal Income Taxes
Customer-Generators **(CG)**	- ROI to Lenders/Investors - MA Residential RE Tax Credit - Federal Incentives (ITC)	- System Installed Costs - Lease Payments - PILOTs/Property Taxes - MA and Federal Income Taxes
Non-Participating Ratepayers **(NPR)**	- MA Income Taxes	- Federal Income Taxes - Federal Incentives (ITC) - MA Residential RE Tax Credit
Citizens of	- System Installed Costs	- Federal Income Taxes

[106] This analysis Ignored potential differential impacts on installed costs related to what might be referred to as "installer incentive capture". It does not explicitly assume or analyze installed cost inflation under the more 'generous' policy options (compared to less generous policies), an installer 'incentive capture' phenomenon cited by some analysts, or assume lower installed costs for policy futures with less generous combined solar and NM incentives.

the Commonwealth at Large (C@L)	- Lease Payments - PILOTs/Property Taxes - MA Income Taxes - ROI to Lenders/Investors	-

D.3.1 System Installed Costs

System installed costs include the total upfront capital cost (and the replacement of the inverter) for solar PV systems installed in Massachusetts under the net energy metering program.

To understand the variation in installed costs, the analysis utilizes an installed cost forecast, as derived for each subsector. The costs were then further differentiated by project size and the type of solar PV installation in question. The initial installed cost that served as the basis for each subsector forecast is based on historic data from both publicly-available sources, as well as with data obtained through supplemental research. The costs of interconnection are assumed to increase at the rate of inflation, and (for ease of estimation) the inverter replacement is assumed to be covered by the initial 25-year warranty included in the upfront system cost.

The assumptions used in projecting PV system installed costs are detailed in Appendix A.

Overall, the total cost associated with solar PV systems will be borne by the customer-generator as the owner and investor in the system, while the in-state share of that total cost comes as a benefit to the citizens of Massachusetts at large. The distribution of these costs does not vary across the differing policy futures. The table below outlines the costs and benefits accruing to the four perspectives.

Table 78: PV System Installed Cost Impacts by Perspective

Policy	Participants		Non-participating Ratepayers	Citizens of MA at Large
	Non-Owner Participants	Customer-generator (CG)		
All	n/a	**Total Cost**	n/a	% total cost retained in state [1] *Macroeconomic impacts [2]*
Notes:	[1] Insufficient data/time for detailed analysis; explored parametrically. Potential area for further study. [2] Beyond scope; Potential area for further study			

D.3.2 Ongoing O&M and Insurance Costs

Ongoing operations and maintenance (O&M) and insurance costs include the fixed O&M, as well as the cost of insuring a solar PV system (typically to ensure financing), for PV systems of all sizes.

In a way similar to the installed cost estimates, the O&M cost estimates utilized in this analysis have been derived for each subsector through the use of publicly-available data, supplemented by additional research using private sources. All O&M costs are reported as a fixed $/kW-year, escalating annually at the rate of inflation. No variable O&M costs were modeled. To calculate annual insurance expenses, the cost was estimated as a specified percentage of the total project cost. The cost of project management was considered separately.

The costs of ongoing O&M and insurance are borne in all policy futures by the customer-generator, while benefits accrue in all scenarios to eligible non-owner participants and MA citizens at large. The table below illustrates the distribution of the costs and benefits across the four perspectives under consideration.

Table 79: Ongoing O&M + Insurance Costs Impacts by Perspective

Policy	Participants		Non-participating Ratepayers	Citizens of MA at Large
	Non-Owner Participants	Customer-generator (CG)		
All	n/a	**Total Cost**	n/a	% total cost retained in state [1] *Macroeconomic impacts [2]*
Notes:	[1] Insufficient data/time for detailed analysis; explored parametrically. Potential area for further study. [2] Beyond scope; Potential area for further study			

D.3.3 Lease Payments

The lease payments subcategory represents the total value of lease payments paid to land or other property owners for systems greater than 25 kW for the right to lease the land upon which a solar PV system is sited.

The analysis assumes a range of lease payment costs ranging from $12-$14/kW per year for systems over 25 kW. This assumption was developed through market analysis, which allowed for the appropriate benchmarking of this range of costs. Calculation of the impacts of lease payments were limited to systems over 25 kW, given that systems under 25 kW (including residential & small commercial roof-mounted systems, or commercial emergency power installations) tend not to require the lease of land, or are roof-mounted on a customer generator or non-owner participant's property. Lease payments are only considered in the analysis of costs and benefits insofar as the lease payments are additive to estimated PPA or VNM discounts to 3rd-party owned system hosts. These costs were held constant across the baseline scenarios, as well as across all alternative policy futures examined.

Overall, benefits associated with lease payments accrue to non-owner participants, as therefore also to citizens of Massachusetts at large. The costs are solely borne by customer-generators, and do not affect non-participating ratepayers. The distribution of these cost and benefit impacts do not change in either of the alternative policy scenarios. The table below illustrates the cost-benefit impacts of lease payments for systems over 25 kW by relevant cost-benefit perspective.

Table 80: Land Lease Payments Impacts by Perspective

Policy	Participants		Non-participating Ratepayers	Citizens of MA at Large
	Non-Owner Participants	Customer-generator (CG)		
All	**Payments [1]**	• **Assume: HO = 0; Non-VNM = 0** • **3PO VNM only: assume X% of installations pay lease (when host ≠ off-taker) [2]**	n/a	**Payments [1]** *Macroeconomic impacts [3]*
Notes:	[1] receipt of lease payments . 100% Stay in-state [2] x% = parametric assumption; 1-x% = no lease (value embedded in offtake discounts) [3] Beyond scope; Potential area for further study			

D.3.4 Payments in Lieu of Taxes (PILOTs)/Property Taxes

Property taxes and PILOTs are payments to local governments paid by the owner of property and/or land within their jurisdiction. These payments apply to solar PV systems, to the extent that systems are not exempt from paying them.

In general, the treatment of property taxes and PILOTs treatment varies widely across the Commonwealth. Thus, the assumptions for this analysis were developed through extensive market analysis and benchmarking. The results of this benchmarking exercise support a base case assumption of $10/kW-year. As with lease payments, when the landowner or NMC offtaker is also the taxing authority, PILOTs and property taxes are only considered insofar as the lease payments are additive to the our estimates of NMC or PPA discounts.

The costs associated with PILOTs and property taxes are borne by customer-generators, but the net local government revenue results generally in direct benefits for citizens at large, and do not affect non-participating ratepayers. The table below illustrates the distribution of related costs and benefits.

Table 81: PILOTs / Property Taxes Impacts by Perspective

Policy	Participants		Non-participating Ratepayers	Citizens of MA at Large
	Non-Owner Participants	Customer-generator (CG)		
All	**Payments**	• **On-site load & HO: assume exempt** • **If 3PO, (i) if host = off-taker, assume embedded in discount; (ii) otherwise assume Prop. Tax or PILOT payment made**	n/a	**Payments** *Macroeconomic impacts* [1]
Notes:	[1] Beyond scope; Potential area for further study			

D.3.5 Aggregate Return to Debt & Equity

The aggregate returns to debt lenders and equity investors constitutes the difference between revenue and costs necessary to provide sufficient rents/profits to the customer-generator system owners and/or investors to induce investment. As such, it is **NOT SHOWN** in the tallying of costs and benefits; rather, it is represented as the difference between calculated costs and benefits. It was necessary however, to calculate the before tax returns to investors in order to estimate tax liabilities, and in addition, to estimate the proportion of these returns retained in state (a benefit from the perspective of citizens at large).

For the purposes of this analysis, the returns to lenders and/or equity investors is the sum of 1) the debt interest, 2 the required returns for meeting the threshold rate of return for investment, and 3) the economic rents/profits made by the system's owners. The analysis assumes that the returns are the net present value of total project revenue, less the net present value of the total costs, and will, in sum, vary across policy futures.

These returns do not come at a direct cost to any perspective. The portion retained in state is a benefit to customer-generators and citizens at large through enhanced economic activity, without affecting non-owner participants or non-participating ratepayers. The nature of these flows is consistent across policy futures, and is illustrated in the table below.

Table 82: Aggregate Return to Debt & Equity Impacts by Perspective

Policy	Participants		Non-participating Ratepayers	Citizens of MA at Large
	Non-Owner Participants	Customer-generator (CG)		
All	n/a	**Calculated value of revenue - cost**	n/a	30% total payments retained in state [1] *Macroeconomic impacts [2]*
Notes:	**[1] Percentage difficult to determine and may evolve; explored parametrically. Potential area for further study. Use 30% and explore sensitivity.** [2] Beyond scope; Potential area for further study			

D.3.6 Massachusetts Residential Renewable Energy Tax Credit

The Massachusetts residential renewable energy tax credit is a tax credit taken on the value of a solar PV system by customer-generators who host a system they own. Since the credit is only open to the owner or tenant of a residential property, it cannot be monetized by 3rd-party customer-generators.

The state tax credit is equal to the lesser of 15% of the total system cost or $1,000. Any tax credits in excess of the value of an individual taxpayer's total tax liability present in the first year may be carried forward to future tax returns for three years. Given that the total number of residential solar PV customers will vary considerably across policy futures, the total value of this tax credit will also vary accordingly.

The state tax credit accrues as a benefit to residential host owners only, while coming as a cost to non-participating ratepayers in the form of the non-participant's share of the cost of the tax credit. The assumption is that benefits and costs associated with the tax credit net to zero for the citizens of Massachusetts at large, which include both participants and non-participants alike. The table below shows the distribution of these costs and benefits.

Table 83: MA Residential RE Tax Credit Impacts by Perspective

Policy	Participants		Non-participating Ratepayers	Citizens of MA at Large
	Non-Owner Participants	Customer-generator (CG)		
All	n/a	**Res HO Only: offset to system installed cost**, *less participant's share of tax payments*	**Total Tax Payments *** *non-participants share of tax payments*	**Assume all retained in state, net to zero**
Notes:	Everyone including participants assumed to be a taxpayer			

D.3.7 Massachusetts Income Taxes

The Massachusetts state income taxes used in this analysis comprise the net value of taxes paid to the state as a result of solar PV eligible for net energy metering.

In order to calculate the direct costs and benefits of paying Massachusetts income taxes, the analysis assumes that a solar PV project's taxable income increases as revenues increase, and decreases based on expenses and depreciation. Overall, the analysis contains several assumptions related to individual and corporate taxation. First, it is assumed that individuals and government entities cannot depreciate their assets for the purpose of taxation, nor are they subject to income tax related to project revenue or savings associated with savings from PPAs and net metering credits. In terms of business taxpayers, it is assumed that all eligible taxpayers have the "tax appetite" (meaning a sufficient degree of taxable income) to take full advantage of the credit, as well as accelerated depreciation. The analysis also assumed that businesses would be subject to a range of tax rates, from 5.25% for small commercial host-owned systems to 8.25% for private third-party owned systems. Finally, the analysis assumes that private non-residential non-owner participants also will incur increased tax liability, given that increase PPA and net metering credit revenue (as well as potential revenue from lease payments) results in an increase in taxable income as a result of lower operating expenses.

Overall, Massachusetts taxes associated with solar PV systems come as a cost to participants, but accrue as a benefit to non-participating ratepayers. Benefits to the citizens of Massachusetts at large are assumed to net to zero. The table below illustrates the distribution of these costs and benefits across the four key perspectives, under various policy futures.

Table 84: MA Income Taxes Impacts by Perspective

Policy	Participants		Non-participating Ratepayers	Citizens of MA at Large
	Non-Owner Participants	Customer-generator (CG)		
All	[PPA / NMC discounts and/or lease payments] * MA tax rate [1]	Business Only: ((Pre-tax net income less depreciation) * MA tax rate)	Total increase in MA tax revenue	**Assume net to zero**
Notes:	[1] for all other than residents and government entities			

D.3.8 Federal Incentives (Investment Tax Credit)

Federal incentives refer, in this analysis, to the federal investment tax credit (ITC), for which solar PV is currently an eligible technology. The Federal ITC for solar PV systems is 30% of the total value of the system. Under current federal law, the credit for non-residential owners (including third-party owners) will drop to 10%, while the credit residential host-owned systems will drop to 0%. These credit values are maintained across all policy scenarios, given that the credit will be taken (or not taken) independent of Massachusetts' policy choices.

The value of the federal ITC is enjoyed strictly as a benefit in Massachusetts, specifically in terms of lower system costs for customer-generators, as well as the in-state share of the total share of the remaining direct economic value of solar PV systems retained in state to the benefit of the citizens of Massachusetts at large. The table below illustrates the distribution of these benefits.

Table 85: Federal Incentives (ITC) Impacts by Perspective

Policy	Participants		Non-participating Ratepayers	Citizens of MA at Large
	Non-Owner Participants	Customer-generator (CG)		
All	n/a	Reduction to system installed cost [1]	n/a	15% total retained in state [2] *Macroeconomic impacts [3]*
Notes:	[1] Ignore MA small increase of Federal taxes dispersed among all Federal taxpayers countrywide. Difficult to determine and small in consequence. [2] Insufficient data/time for detailed analysis; explored parametrically (Assume 15% based on MA as less than 10% of national (conventional) tax equity market, but inclination for some transactions with local source of (unconventional) tax equity). Potential area for further study. [3] Beyond scope; Potential area for further study			

D.3.9 Federal Income Taxes

The federal income taxes used in this analysis comprise the net value of taxes paid to the federal government as a result of solar PV systems eligible for net energy metering. All of the assumptions associated with calculating the impact of Massachusetts state taxes are exactly the same, save for the fact that the taxes in question are paid to the federal government, which also entails different tax rates. The marginal federal corporate and individual tax rate used in this analysis is 35%.

The bulk of the net costs of federal income tax changes fall upon customer-generators and non-owner participants. The cost to customer-generators is the taxable share of their pre-tax net income (less depreciation), while the cost to non-owner participants is represented by the taxable portion of the PPA and net metering credit savings accruing to corporate taxpayers. On net, the analysis thus assumes that federal income tax changes come at a net direct cost (without accounting for any indirect or induced economic impacts) to the citizens of Massachusetts. The table below shows the manner in which these benefits are distributed across the four key perspectives, under various policy futures.

Table 86: Federal Income Taxes Impacts by Perspective

Policy	Participants		Non-participating Ratepayers	Citizens of MA at Large
	Non-Owner Participants	Customer-generator (CG)		
All	**PPA / NMC discounts and/or lease payments * Federal tax rate [1][3]**	**(Pre-tax net income less depreciation) * Federal tax rate [1]**	n/a	**Total Tax payments [1]** *Macroeconomic impacts [2]*
Notes:	[1] Ignore MA small increase of Federal tax receipts dispersed among all Federal taxpayers countrywide. Difficult to determine and small in consequence. [2] Beyond scope; Potential area for further study [3] for all other than residents and government entities			

D.4 Category II: Solar Policy

The second major category of costs and benefits considered in this analysis are associated with the costs associated with complying with Massachusetts' RPS pertaining to solar PV systems eligible for net metering. The four subcategories of costs and benefits part of solar policy costs include:

Direct Incentives	CB2.1	Quantitative
Other Solar Policy Compliance Costs	CB2.2	Quantitative
Displaced RPS Class I Compliance Costs	CB2.3	Quantitative
Solar Policy Incremental Admin. & Transaction Costs	CB2.4	Quantitative

In general, the value of these costs and benefits will vary dramatically across policy futures, given that the incentive components of each policy future vary the most across perspectives. The table below illustrates how these subcategories accrue as direct costs or benefits to the four perspectives analyzed.

Table 87: Solar Policy Impact Applicability to Analysis Perspectives

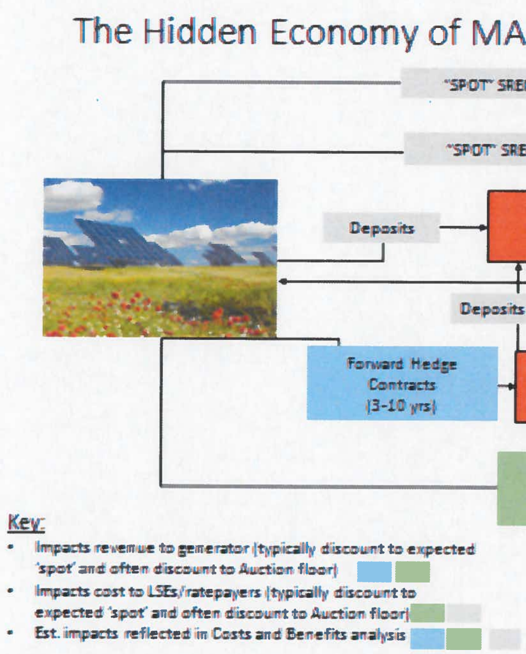
Perspective	Subcategories Accruing as Net Benefits to Some or All With Perspective	Subcategories Accruing as Net Costs to Some or All With Perspective
*Non-Owner Participants **(NOP)***	- N/A	- N/A
*Customer-Generators **(CG)***	- Direct Incentives	- Solar Policy Incremental Admin. and Transaction Costs
*Non-Participating Ratepayers **(NPR)***	- Displaced RPS Class I Compliance Costs	- Direct Incentives - Other Solar Policy Compliance Costs - Solar Policy Incremental Admin. and Transaction Costs
Citizens of the Commonwealth at Large (C@L)	- Displaced RPS Class I Compliance Costs	- Direct Incentives - Solar Policy Incremental Admin. and Transaction Costs

D.4.1 Direct Incentives

Direct incentives include the total incentives directly paid to solar PV projects under all of the policy futures under consideration. Under the extended SREC policy scenario, these incentives take the form of SRECs as well as other incentive payments, including Commonwealth Solar and Solarize incentive payments. Under Policy Paths A and B, these costs will take the form of PBI or EPBI payments, or pass through of gross costs of those payments to ratepayers (netting the value from EDCs reselling energy procured into the market is addressed in other components below). Given the variety of policy futures used in this study, the analysis incorporates a variety of different forms of direct incentives to eligible solar project (including those receiving net metering credits). These incentives are described in detail in Section 2.4.1 and 2.5.1.

To calculate the value of SREC payments, it is important to understand the structure of the existing SREC markets, as well as how a hypothetical program (SREC-III) that extends the basic structure of SREC-I and SREC-II to 2025. Figure 76 is an illustration of the main structural flows and features of the Massachusetts SREC market, underscoring the hedging transactions that result in revenues to generators differing from costs to ratepayers.

Figure 76: Schematic Diagram of Hedging Transactions within the SREC Carve-out Market



To represent these effects, the analysis uses Sustainable Energy Advantage, LLC's proprietary Solar Market Study model to model SREC values based on a supply-responsive demand formula. To estimate policy costs under the alternative Policy Paths A & B discussed in Section 2.4 and 0, SEA developed custom models purpose-built for this analysis.

Nevertheless, the use of supply curves is a common feature to both models. This analysis relies on modeling the economics of over 700 solar PV "supply blocks", which represent the various types of solar PV systems that can be built in Massachusetts and are eligible for applicable incentives, as subdivided by:

- The local EDC territory the project is located in;
- The size and characteristics of the project;
- The ownership structure of the project;
- The rate class of the end-user (or other off-taker); and
- Other appropriate characteristics.

To model the production of these systems, solar PV production data from the National Renewable Energy Laboratory's PVWatts model, which uses Worcester, MA as the proxy location for all system output.

The models used to estimate the total value of applicable incentives uses a proprietary modified version of the publically available Cost of Renewable Energy Spreadsheet Tool (CREST) model, a model designed by SEA for NREL. The model uses a variety of inputs, including fixed capital costs, all applicable project revenues (including uncontracted revenues), as well as financing assumptions, ownership, and the degree of hedged vs. unhedged risk exposure commodity, among many others. Finally, the analysis also assumes that investors value post-incentive Class I RPS RECs in their pro formas at $5/MWh. The supply curve assumptions are discussed further in Appendix A.

Table 88: Direct Incentives Impacts by Perspective

Policy	Participants		Non-participating Ratepayers	Citizens of MA at Large
	Non-Owner Participants	Customer-generator (CG)		
SREC	Assumed N/A	**Solar incentive revenues (taking into account LSE hedging) + CommSolar+Solarize Payments**	**Solar incentive payments (taking into account LSE hedging) + CommSolar+Solarize Costs**	**Solar incentive payments (taking into account LSE hedging) + CommSolar Costs [1]** *Macroeconomic impacts [2]*
A & B		**Incentive Payments**	**Funding of Incentive Payments**	**Funding of Incentive Payments** *Macroeconomic impacts [2]*
Notes:	[1] Assume all transaction costs, market maker margins and payments to run auction leave the state [2] Beyond scope; Potential area for further study			

D.4.2 Other Solar Policy Compliance Costs

Solar policy compliance costs outside of direct incentives include the solar alternative compliance payment (SACP) revenues collected by DOER. Under Policy Paths A and B, these revenues would not be collected, as the SREC program would be replaced by the new incentive regimes described in Sections 2.3, 2.4 and 0.

Both historic and projected SACPs were utilized in calculating the baseline SREC policy scenario. The total quantity of SACPs needed under SREC-I, SREC-II and SREC-III was calculated using SEA's proprietary Massachusetts Solar Market Study Model. Speciifc assumptions are included in Appendix A.

Table 89: Other Solar Policy Compliance Costs Impacts by Perspective

Policy	Participants		Non-participating Ratepayers	Citizens of MA at Large
	Non-Owner Participants	Customer-generator (CG)		
SREC	N/A	N/A	**SACP**	**SACP – DOER expenditures in State = 0** [1]
A & B	N/A	N/A	N/A	N/A
Notes:	[1] assume all DOER SACP $ spent in state			

D.4.3 Displaced RPS Class I Compliance Costs

In any of the policy futures considered, the SREC or REC created obviates the need for, or serves to fulfill, a unit of Massachusetts Class I RPS compliance. Solar PV production can displace RPS Class I compliance costs in two ways: 1) through eliminating the need to purchase non-solar Class I RECs (by meeting the Solar Carve-Out or minting a Class I solar REC), and 2) via behind-the-meter production (and instantaneous consumption) that reduces overall load. Thus, under the "SREC Policy" future, the analysis assumes that SRECs purchased avoid non-solar Class I purchases, as do the Class I RECs purchased via the upfront and performance-based incentives in place under Policy Path A and B.

For each policy future, cases are considered in which either 1) the Solar Carve-Out displaces Class I wind RECs or 2) displaces payments of Class I ACPs under a shortfall in Class I RPS supply.

Table 90: Displaced RPS Class I Compliance Costs Impacts by Perspective

Policy	Participants		Non-participating Ratepayers	Citizens of MA at Large
	Non-Owner Participants	Customer-generator (CG)		
SREC, A & B	N/A	N/A	Avoided Class I RPS Costs	Avoided Class I RPS Costs
Notes:				

D.4.4 Solar Policy Incremental Administrative and Transaction Costs

SEA modeled incremental solar policy administrative and transaction costs as discussed in Appendix A. The costs in Appendix A represented the estimated one-time and ongoing costs for a single large EDC (National Grid or Eversource, and were scaled up to apply to the entire Massachusetts market. Costs in this category for SREC policies are built into SEA's proprietary MA Solar Market Study model. In addition, under Policy Path A, developers seeking incentives must compete for PBIs, and (based on experience elsewhere) must incur costs to make more than one sale (to a host), on average, in order to secure incentives for winning bids. This 'dry hole' cost represents additional overhead compared to an open incentive in which developers must make one sale per incentive contract. The estimate of these costs is detailed in Appendix A.

Table 91: Solar Policy Incremental Admin. & Transaction Costs Impacts by Perspective

Policy	Participants		Non-participating Ratepayers	Citizens of MA at Large
	Non-Owner Participants	Customer-generator (CG)		
SREC	N/A	N/A	Negligible [1]	Negligible [1]
A	N/A	For large projects competing for PBI, Additional developer overhead due to the need to sell both winning and losing bids assumed passed along to CGs [2]	Est. EDC costs [3] + CG additional develop overhead [2]	Est. EDC costs [3] + additional developer overhead [2]
B	N/A	N/A	Est. EDC costs [3]	Est. EDC costs [3]
Notes:	[1] Ignore DOER admin costs as small; [2] estimated based on Cust. Acquisition cost data and bid/selection ratio est.; included here to capture impact since not modeled as higher installed cost under Path A. [3] estimate based on data from EDCs			

D.5 Category III: Behind-the-Meter Production within the Billing Month

The third major category of costs and benefits considered in this analysis are associated with the cost of grid-tied solar PV systems eligible for net metering. The four subcategories of costs and benefits contained within the category of behind-the-meter production include:

Generation Value of On-site Generation	CB3.1	Quantitative
Transmission Value of On-site Generation	CB3.2	Quantitative
Distribution Value of On-site Generation	CB3.3	Quantitative
Other Retail Bill Components (Transition, EE, RE)	CB3.4	Quantitative

In general, the value of these costs and benefits will vary somewhat across policy futures, given that the treatment of behind-the-meter production in each policy future can vary due to changing installation mix and volumes.

The table below illustrates how these subcategories accrue as direct costs or benefits to the four perspectives analyzed.

Table 92: BTM Production within the Billing Month Applicability to Analysis Perspectives

Perspective	Subcategories Accruing as Net Benefits to Some or All With Perspective	Subcategories Accruing as Net Costs to Some or All With Perspective
*Non-Owner Participants **(NOP)***	- Generation Value of On-Site Generation - Transmission Value of On-Site Generation - "Adjusted" Distribution Value of On-Site Generation - Other Retail Bill Components (Trans., RE, EE)	- N/A
*Customer-Generators **(CG)***	- Generation Value of On-Site Generation - Transmission Value of On-Site Generation - "Adjusted" Distribution Value of On-Site Generation - Other Retail Bill Components (Trans., RE, EE) [1]	- N/A
*Non-Participating Ratepayers **(NPR)***	- Generation Value of On-Site Generation	- Transmission Value of On-Site Generation - "Adjusted" Distribution Value of On-Site Generation - Other Retail Bill Components (Trans., RE, EE)
Citizens of the Commonwealth at Large (CC@L)	- Generation Value of On-Site Generation - Other Retail Bill Components (Trans., RE, EE)	- N/A

[1] SREC Policy & Policy Path B Only

D.5.1 Generation Value of On-Site Generation

The generation value of on-site generation is the avoided cost value of generation service obviated by the reduction in total customer load (and thus retail purchases) caused by the on-site solar PV generation. The portion of on-site solar PV generation that is consumed simultaneously by the host customer reduces a customer's load, thus avoiding retail kilowatt-hour purchases of energy at a 1-to-1 rate. Thus, a portion of the cost avoided is the cost of generation service that the customer would otherwise receive in the absence of a solar PV system. This value is represented by the generation or "G" component of a customer's bill, remains consistent through all three policy futures, and offsets purchases in that month only. For ease of calculation, the study utilizes the Basic Service generation rate offered by each EDC.

Table 93: Generation Value of On-site Generation Impacts by Perspective

Policy	Participants		Non-participating Ratepayers	Citizens of MA at Large
	Non-Owner Participants	Customer-generator (CG)		
All	**HO: n/a** **3PO: PPA discount on G**	**HO: Retail billing unit savings** **3PO: Retail billing unit savings less 'discount' to host**	**Avoided energy losses [2]**	**Sum of benefits [1]**
Notes:	[1] Sum of Participants benefits should be reduced by dollars that would have been spent on in-state renewable generation (if not for solar). Assume w/o solar carve-out the marginal RPS demand would be met with out-of-state wind, then reduction → is zero. [2] using production wtd energy loss factor			

D.5.2 Transmission Value of On-Site Generation

The transmission value of on-site generation is the value of the transmission service obviated by the reduction in total customer load (and thus retail purchases) caused by the on-site solar PV generation. Similar to generation service, the portion of on-site solar PV generation that is consumed simultaneously by the host customer reduces a customer's load, thus avoiding retail kilowatt-hour purchases of energy at a 1-to-1 rate. Thus, a portion of the cost avoided is the cost of generation service that the customer would otherwise receive in the absence of a solar PV system. This value is avoided equally across all policy futures examined, is represented by the transmission or "T" component of a customer's bill by applicable EDC, and offsets purchases in that month only.

Table 94: Transmission Value of On-site Generation Impacts by Perspective

Policy	Participants		Non-participating Ratepayers	Citizens of MA at Large
	Non-Owner Participants	Customer-generator (CG)		
SREC, A & B	**HO: n/a** **3PO: PPA discount on T**	**HO: Retail billing unit savings** **3PO: Retail billing unit savings less 'discount' to host**	**Portion of T shifted to other MA ratepayers**	n/a (transfer payment from non-participants to participants)
Notes:	T rates can vary by rate class, time of day, and season.			

D.5.3 "Adjusted" Distribution Value of On-Site Generation

The "adjusted" distribution value of on-site generation is the avoided cost value of the distribution service obviated by the reduction in total customer load (and thus retail purchases) caused by the on-site solar PV generation. The rates used for this calculation are the adjusted values published by the EDCs which incorporate a range of charges and credits carried or passed through the distribution rates, other than the charges explicitly addressed in Section D.5.4. While the degree of distribution service avoided by net solar generation that exceeds a customer's needs at a given time is a somewhat more complex question, the portion of on-site solar PV generation that is consumed simultaneously by the host customer reduces a customer's load, thus avoiding retail kilowatt-hour distribution service of energy at a 1-to-1 rate. Thus, a portion of the cost avoided is the cost of generation service that the customer would otherwise receive in the absence of a solar PV system. This value is avoided equally across all policy futures examined, and represented by the adjusted distribution or "D" component of a customer's bill by applicable EDC, and offsets purchases in that month only.

Table 95: "Adjusted" Distribution Value of On-site Generation Impacts by Perspective

Policy	Participants		Non-participating Ratepayers	Citizens of MA at Large
	Non-Owner Participants	Customer-generator (CG)		
SREC, A & B	HO: n/a 3PO: PPA discount on Adjusted D	HO: Retail billing unit savings 3PO: Retail billing unit savings less 'discount' to host	D rate component shifted to other MA ratepayers	n/a (transfer payment from non-participants to participants)
Notes:	"Adjusted " for miscellaneous charges. See example links in speaker notes. Distribution rates can vary by rate class, TOD & season.			

D.5.4 Other Retail Bill Components

The other retail bill components avoided by on-site generation are the avoided cost values of the other charges obviated by the reduction in total customer load (and thus retail purchases) caused by the on-site solar PV generation. As with generation, transmission and distribution service components avoided by on-site generation, the other bill components, which include transition, energy efficiency, renewable energy and others charges, are also avoided on by on-site generation.

Table 96: Other Retail Bill Components (Transition, EE, RE) Impacts by Perspective

Policy	Participants		Non-participating Ratepayers	Citizens of MA at Large
	Non-Owner Participants	Customer-generator (CG)		
SREC, A & B	HO: n/a 3PO: PPA Discount Other	HO: Retail billing unit savings 3PO: Retail billing unit savings less 'discount' to host	TR & EE [1]	Avoided RE Charge payments *macro-economic benefits of spending lost*
Notes:	"Adjusted " Transition for miscellaneous charges. See example links below. Transition rates can vary by rate class. [1] TR and EE total collections are fixed, so shifted to other customers. Decreased renewable energy collections are not recovered from ratepayers			

D.6 Category IV: Net Metering Credits beyond the Billing Month (Including Virtual Net Metering)

The fourth major category of costs and benefits considered in this analysis are associated with the costs associated with net metering credits beyond the billing month pertaining to PV systems eligible for net metering. The four subcategories of costs and benefits associated with net metering credits beyond the billing month costs include:

Offsetting On-site Usage	CB4.1	Quantitative
Virtual NM	CB4.2	Quantitative
Wholesale Market Sales	CB4.3	Quantitative
Virtual NM Administrative Costs	CB4.4	*Qualitative*

It is important to note that these values tend to vary with the amount and types of solar PV installed and producing, and vary materially between different policy futures. However, these specific values are assumed to be the same per megawatt-hour (MWh) across all policy futures, given that total amount of PV production across all scenarios does not vary dramatically. The table below illustrates the cost and benefit subcategories within this category accruing (on net) to each perspective.

Table 97: Net Metering Credits beyond the Billing Month (Including Virtual Net Metering) Applicability to Analysis Perspectives

Perspective	Subcategories Accruing as Benefits	Subcategories Accruing as Costs

*Non-Owner Participants **(NOP)***	- Offsetting On-Site Usage Beyond the Billing Month - Virtual NM	- N/A
*Customer-Generators **(CG)***	- Offsetting On-Site Usage Beyond the Billing Month - Virtual NM - Wholesale Market Sales	- N/A
*Non-Participating Ratepayers **(NPR)***	- N/A	- Offsetting On-Site Usage Beyond the Billing Month [1] - Virtual NM - VNM Admin Costs
Citizens of the Commonwealth at Large (CC@L)	- Offsetting On-Site Usage Beyond the Billing Month - Virtual NM - Wholesale Market Sales	- VNM Admin Costs
[1] SREC Policy and Path B Only		

D.6.1 Offsetting On-Site Usage beyond the Billing Month

The on-site usage offset beyond the billing month is comprised of the net excess generation from the solar PV system, which is the share of generation from the system that exceeds the customer's load during the billing month, and is carried over to a subsequent month. For the purposes of this study, the rate treatment of net metering credits remains the same in Policy Path B as in the SREC policies baseline future, which is the sum of the per kilowatt-hour value of the generation, transmission, transition charge and the adjusted distribution component of customer bills. However, the net metering credit under Policy Path A is set at the wholesale value of electricity. These values have also been adjusted to account for line losses, as described in detail in Section 3.2.

Table 98: Offsetting On-site Usage Beyond Current Billing Month Impacts by Perspective

Policy	Participants		Non-participating Ratepayers	Citizens of MA at Large
	Non-Owner Participants	Customer-generator (CG)		
SREC & B	3PO NMC discounts to host	NMC Revenue = (i) HO = 100% NMC revenue + (ii) 3PO = NMC less 3PO discounts	[NMCs] less [W/S value [3] (solar production-wtd) for EDC]	NMC Revenue - (NMCs less W/S value for EDC) = WS rate [3]
A	3PO NMC discounts to host [2]	NMC Revenue = (i) HO =100% NMC revenue + (ii) 3PO = NMC less 3PO discounts [2]	n/a (costs and revenues net to 0) + Avoided energy losses	NMC Revenue * (1+ production-wtd energy losses)
Notes:	[1] Private Class III NMC does not include Distribution rates [2] Discount likely to be small or zero when value of NMC is just wholesale value **[3] This will be loss adjusted using production wtd energy loss factor**			

D.6.2 Virtual Net Metering

Virtual net metering credits include the allowed retail credit value of bill credits accruing to a non-owner participating customer as a result of a remote solar PV system they have entered into a contract with. Under the SREC policy and Policy Path B the value of VNM credits is set by current statute (and varies depending on whether a project is a Class I, Class II or Class III net metering facility and whether or not it is a government customer), the value of this credit in Policy

Path A is reduced to the value of the wholesale value of electricity. The treatment of net metering credits for virtually net metered systems would be analogous to the treatment of customer-hosted systems.

Table 99: Virtual Net Metering Impacts by Perspective

Policy	Participants		Non-participating Ratepayers	Citizens of MA at Large
	Non-Owner Participants	Customer-generator (CG)		
SREC & B	3PO NMC discounts to NM offtaker	NMC Revenue = (i) HO= 100% NMC revenue + (ii) 3PO = NMC less 3PO discounts	[NMCs] less [W/S value [3] (solar production-wtd) for EDC]	NMC Revenue - (NMCs less W/S value for EDC) = WS rate [3]
A	3PO NMC discounts to NM offtake [2]	NMC Revenue = (i) HO =100% NMC revenue + (ii) 3PO = NMC less 3PO discounts [2]	n/a (costs and revenues net to 0) + Avoided energy losses	NMC Revenue * (1+ production-wtd energy losses)
Notes:	[1] Private Class III NMC does not include Distribution rates [2] Discount likely to be small or zero when value of NMC is wholesale generation value **[3] This will be loss adjusted using production wtd energy loss factor**			

D.6.3 Wholesale Market Sales

Wholesale market sales include the value of the sales by distributed solar PV systems in excess of on-site load which is not eligible for net metering. This production is sold into the wholesale electricity market. In terms of the three policy futures in the current analysis, these costs and benefits will play a more significant role in scenarios where net metering caps are maintained. While it is a largely negligible issue today, wholesale market sales by large distributed solar PV systems will become more relevant once statutory net metering program caps are reached, and more customer generators begin to focus on sales to the wholesale market. Thus, it is important to ensure that, depending on the point at which distributed PV deployment reaches both the private and public caps for all utilities (in policy futures and sub-scenarios where caps are maintained), the wholesale generator rate applies to the portion of supply that might constitute a wholesale market sale, even for some oversized behind-the-meter projects.

To ensure that this is done appropriately, the analysis utilizes projections of the production-weighted wholesale value of solar PV production on a cost per megawatt-hour ($/MWh basis. These projections were created using the AURORA model, which simulates economic dispatch of electricity, described in Appendix A. For ease of estimation, the same value per MWh is used across all policy futures, given that each policy future results in only moderately different solar PV capacity and energy production per year (relative to ISO New England scale).

Table 100: Wholesale Market Sales Impacts by Perspective

Policy	Participants		Non-participating Ratepayers	Citizens of MA at Large
	Non-Owner Participants	Customer-generator (CG)		
SREC, A & B	n/a	Wholesale Market Revenue from sales to Grid	Avoided energy losses	Sum of Benefits = Wholesale Market Revenue from sales to Grid * (1+ production-wtd energy losses)
Notes:				

D.6.4 Virtual Net Metering Administrative Costs

Virtual net metering (VNM) administrative costs are the costs incurred associated with billing, metering and other costs involved in administering a VNM program. EDC costs associated with these activities will continue to apply to varying degrees in the different policy futures studied. If a customer chooses to enter into a virtual net metering arrangement, that customer is required to designate beneficiary customer accounts, and do so using a Schedule Z form to do so. Given that these processes are not fully automated and are often done manually, the EDCs have noted that they must incur added costs to manually account for virtual net metering credits on the monthly bills of beneficiary accounts. To this end, some historical data was offered by Eversource Energy regarding their calculation of these costs during or prior to 2013, when the volume of virtual net metering was well below the current level.

After review of this data, the consulting team concluded that, while the cost component is certainly legitimate and potentially sufficient in magnitude to slightly impact the results of his analysis, that the data provided as difficult to extrapolate reasonably to future VNM scale, given that (1) billing systems may evolve to more efficiently account for VNM customers and beneficiary accounts and (2) EDCs could potentially avoid a material portion of such costs by deciding to cut a check to the VNM facility rather than allocate VNM credits. In any event, this category is acknowledged as a valid cost component that has not been quantified for this study.

Table 101: VNM Admin Costs Impacts by Perspective

Policy	Participants		Non-participating Ratepayers	Citizens of MA at Large
	Non-Owner Participants	Customer-generator (CG)		
All, to varying degrees, but more pertinent when NM not capped	N/A	N/A	*Est. EDC costs*	*Est. EDC costs*

D.7 Category V: Electric Market

The fifth major category of costs and benefits considered in this analysis are associated with the costs associated with avoided wholesale energy market costs pertaining to PV systems eligible for net metering. The five subcategories of costs and benefits contained within avoided electric market costs include:

Wholesale Market Price Impacts – Energy	CB5.1	Quantitative
Wholesale Market Price Impacts – Capacity	CB5.2	*Qualitative*
Avoided Generation Capacity Costs	CB5.3	Quantitative
Avoided Line Losses	CB5.4	Quantitative
Avoided Transmission Tariff Charges	CB5.5	Quantitative

It is important to note that these values tend to vary with the amount of solar PV installed and producing. However, these specific values are assumed to be the same per megawatt-hour (MWh) across all policy futures, with these values scaled to the actual solar PV production volumes projected in each instance. The table below illustrates the cost and benefit subcategories within this category accruing (on net) to each perspective.

Table 102: Electric Market Impacts Applicability to Analysis Perspectives

Perspective	Subcategories Accruing as Benefits to Some or All With Perspective	Subcategories Accruing as Costs to All or Some With Perspective

*Non-Owner Participants **(NOP)***	- N/A	- N/A
*Customer-Generators **(CG)***	- Avoided Generation Capacity Costs - Avoided Transmission Tariff Charges [1]	- N/A
*Non-Participating Ratepayers **(NPR)***	- Wholesale Market Impacts – Energy - Wholesale Market Impacts – Capacity [1] - Avoided Generation Capacity Costs (and Avoided Capacity Reserves) - Avoided Line Losses - Avoided Transmission Tariff Charges [1]	- N/A
*Citizens of the Commonwealth at Large **(CC@L)***	- Wholesale Market Impacts – Energy - Wholesale Market Impacts – Capacity [1] - Avoided Generation Capacity Costs (and Avoided Capacity Reserves) - Avoided Line Losses - Avoided Transmission Tariff Charges [1]	- N/A
[1] Explored qualitatively		

D.7.1 Wholesale Market Impacts – Energy

Energy-related wholesale market impacts represent the value of the difference in wholesale energy prices due to the impact of solar PV installations which create downward pressure on energy locational marginal prices in New England's bid-based market. These impacts vary between policy futures strictly as it relates to the amount and overall pace of solar PV deployment in each policy future. While energy market price impacts can result in a transfer payment from the perspective of other wholesale generators (a perspective outside of the analysis scope) this price effect can result in short-term market price effects (known in the energy efficiency world by the colorful acronym DRIPE, for demand reduction induced price effect) connected to solar deployment. To measure these effects, the study uses the quantity of PV injected into system in order to determine the change in locational spot LMPs from addition of solar, which is assumed by the analysis to have zero variable costs.

To quantify these effects, the study utilizes the annual results from AURORA dispatch modeling between the solar and no solar cases under both frameworks discussed in Section 1.3. These values were adjusted downward using the approach and assumptions used in the Avoided Energy Supply Cost 2013 study (as discussed further in Appendix A) to reflect (i) the temporary nature of the price impact, and (ii) applied only to assumed fraction of energy consumed in Massachusetts not hedged through long-term contracts (and thus impacted by changes in spot prices).

Table 103: Wholesale Market Price Impacts – Energy Impacts by Perspective

Policy	Participants		Non-participating Ratepayers	Citizens of MA at Large
	Non-Owner Participants	Customer-generator (CG)		
SREC, A & B	n/a	n/a	**Net Energy Market Price Impact [1.2]**	**Net Energy Market Price Impact [1,2]**
Notes:	[1] When solar displace wind, + or - net benefit of wind vs. PV; when displaces nat. gas, + benefit of displacing nat. gas [2] MWh Adjusted upward to reflect avoided production-weighted energy losses			

D.7.2 Wholesale Market Impacts – Capacity

Capacity-related wholesale market impacts represent the impact of injecting solar PV into the system on the regional Forward Capacity Market (FCM) price. As with energy-related wholesale market impacts vary between policy futures strictly as it relates to the amount and overall pace of solar PV deployment in each policy future.

Quantitative measurement of the Forward Capacity Market (FCM) price impacts associated with the injection of an additional quantity of PV into the system is outside of the scope of the analysis. However, in a qualitative sense, while the change in the price of capacity is less likely to be material in scenarios comparing the Solar Carve-Out to a scenario in which wind is the marginal compliance resource (and thus relatively insignificant) ignored In the event PV was incremental, the avoided cost impact, while small, may be more noticeable when compared to natural gas.

Table 104: Wholesale Market Price Impacts – Capacity Impacts by Perspective

Policy	Participants		Non-participating Ratepayers	Citizens of MA at Large
	Non-Owner Participants	Customer-generator (CG)		
SREC, A & B	n/a	n/a	*Net Capacity Market Price Impact*	*Net Capacity Market Price Impact*
Notes:				

D.7.3 Avoided Generation Capacity Costs (Including Avoided Capacity Reserves)

Avoided generation capacity and avoided capacity reserve costs are the costs foregone in the wholesale market associated with the reduced need for capacity as a result of solar PV.

One value associated with distributed solar PV is the degree to which such resources reduce the need for new generation capacity, as well as installed capacity reserves (ICR). This subcategory of costs and benefits addresses (1) components of peak reduction impact, (2) the commensurate reduction in required ICR, and (3) the value of the share of overall solar capacity monetized in the FCM market.

Under net metering tariffs, EDCs control rights to FCM from net metered systems, although to date they have thus far elected not to participate with this FCM in the Forward Capacity Auctions due to risk allocation and a lack of control. Whether they do or not, the claimed capability value of solar will reduce the ICR, thus will accrue to load, once PV is incorporated in ICR forecast as proposed for future FCAs.

In addition, the analysis described in Section 3.1 revealed that solar PV's electric load carrying capacity (ELCC), which decreases as PV penetration increases and shifts peak hours later into the evening, is substantially higher than the Seasonal Claimed Capacity for intermittent renewables in FCM – the value of which is independent of penetration. As Figure 19 in Section 3.1 shows, solar reduces peak, and thus the ICR, to the extent the peak reduction benefit is not fully captured in solar SCC calculations. The analysis in Section 3.1 also calculates the impact on peak reduction from solar PV as a function of penetration, which is used in these calculations. Thus, this analysis derives both the capacity impacts of distributed solar PV, and the installed capacity reserves (ICR), the net of which is the value of avoided capacity reserve requirements and on-peak line losses (also discussed in Section 3.2 and Section D.7.4).

Table 105: Avoided Generation Capacity Costs (Including Avoided Generation Capacity Reserve Costs) Impacts by Perspective

Policy	Participants		Non-participating Ratepayers	Citizens of MA at Large
	Non-Owner Participants	Customer-generator (CG)		
SREC, A & B	n/a	For 28.8% of market directly participating as supply, FCM revenue [1]	Full value of ELCC less amount monetized by CGs may accrue to all ratepayers. (For solar not directly participating in FCM: (i) market value of avoided ICR reduction [2], PLUS (ii) difference between ELCC value (in reducing system ICR) and value as calculated for SCC [3])	ELCC* Value of Capacity [3]
Notes:	[1, 2] Annual MW_{DC} Solar * 1000 kW/MW * FCM price forecast ($/kW-mo) * 12 months * (SCC * 4 mos. + WCC * 8 mos.)* % participating in market; WCC = 0; 28.8% from NESCOE presentation to NEPOOL Reliability Committee: *Accurate ICR Calculation Approach, 11/19/14* → citing [56 MW of DR PV with CSOs + 85 MW of PV with included on the load side for the FCA9 ICR calculation] divided by 489 MW total forecast = 28.8% [3] Annual MW_{DC} Solar * 1000 kW/MW * ELCC Peak reduction % * FCM price forecast ($/kW-mo) * 12 months * (1+reserve%) * (1+peak loss factor).			

D.7.4 Avoided Line Losses

Line losses represent the generated energy that is lost due to electrical resistance in the process of delivering (i.e. transmitting and distributing) electricity from source to sink. The derivation of loss factors in discussed in Section 3.2. The applicable loss factors are applied to individual cost and benefit components throughout this study, rather than being tallied explicitly as an individual line item. The value of avoided *marginal* losses due to locating generation on the periphery of the distribution system near load is not captured by prices for generation, but accrues broadly to load, and thus to all ratepayers. Thus, the study adjusts many of the costs and benefit subcategories within this analysis using a solar production-weighted line loss formula based on statewide average line loss figures outlined in Table 42 in Section 3.2.

D.7.5 Avoided Transmission Tariff Charges

Avoided transmission tariff charges represent the ISO New England Regional Network Service (RNS) cost reductions caused by coincident solar peak load reduction. While solar PV deployment does not reduce the ISO's total transmission revenue requirement, through the reduction in billing units costs are shifted to other states (in concert with increased per-kW rates). Through this mechanism, Massachusetts distributed solar PV installations can shift 1 minus the state's load ration share. In the absence of installing distributed generation in state, similar policies implemented in other states would have the effect of shifting load to Massachusetts, so this can be thought of as defensive in nature.

Table 106: Avoided Transmission Tariff Charges Impacts by Perspective

Policy	Participants		Non-participating Ratepayers	Citizens of MA at Large
	Non-Owner Participants	Customer-generator (CG)		
SREC, A & B	n/a	*On-site load: % of RNS avoided * on-site load not displaced by PV [1]* *NM Credits: Reduction to NMC value due to lower TX rates [1]*	RNS Charges avoided (shifted) for all load [2]	RNS Charges avoided (shifted) for all load [2]
Notes:	[1] very small, ignore [2] Each year $ value = **[RNS rate ($/kw-yr*1000kW/MW) * [(case-specific RNS% reduction per MW_{DC}) * (case-specific Avg MD(DC) during year)*(1+peak T&D losses)]*(1-MA LRS)**			

D.8 Category VI: Electric Investment Impacts

The sixth major category of costs and benefits considered in this analysis are associated with the costs associated with avoided electric infrastructure investment costs pertaining to PV systems eligible for net metering. The four subcategories of costs and benefits contained within avoided electric investment costs include:

Avoided Transmission Investment - Remote Wind	CB6.1	Quantitative
Avoided Transmission Investment – Local	CB6.2	Quantitative
Avoided Distribution Investment	CB6.3	Quantitative
Avoided Natural Gas Pipeline	CB6.4	*Qualitative*

It is important to note that these values tend to vary with the amount of solar PV installed and producing. The table below illustrates the cost and benefit subcategories within this category accruing (on net) to each perspective.

Table 107: Electric Investment Impacts Applicability to Analysis Perspectives

Perspective	Subcategories Accruing as Benefits to Some or All With Perspective	Subcategories Accruing as Costs to All or Some With Perspective
*Non-Owner Participants **(NOP)***	- N/A	- N/A
*Customer-Generators **(CG)***	- N/A	- N/A
*Non-Participating Ratepayers **(NPR)***	- Avoided Transmission Investment – Remote Wind - Avoided Transmission Investment – Local - Avoided Distribution Investment - Avoided Natural Gas Pipeline Investment [1]	- N/A
*Citizens of the Commonwealth at Large **(CC@L)***	- Avoided Transmission Investment – Remote Wind - Avoided Transmission Investment – Local - Avoided Distribution Investment - Avoided Natural Gas Pipeline Investment [1]	- N/A

[1] Explored qualitatively

D.8.1 Avoided Transmission Investment – Remote Wind

Avoided transmission investment associated with remote wind installations represents the cost of transmission infrastructure connecting remote wind installations to load centers avoided by solar PV. Given the assumption in this study that RPS compliance in the absence of the Solar Carve-Out would comprise Class I land-based wind RECs, installations of PV in Massachusetts under the Carve-Out can displace cost that would otherwise be incurred to build additional transmission to access wind sited out-of-state. The impact to Massachusetts ratepayers can be represented by the avoided proportion of the cost of transmission not borne by wind generators captured in Class I REC prices, but instead allocated to network load customers (through the ISO-NE RNS tariff). This value can be stated as the net present value of:

$$\begin{aligned} &Total\ \$/MWh\ Avoided \\ &\quad = (Avoided\ Transmission\ \$/MWh\ \ Allocated\ to\ Load * MA\ Load\ Ration\ Share\ for\ ISO \\ &\quad - NE\ Tariff) * MA\ T\&D\ Loss\ Adjustment \end{aligned}$$

Where: $MA\ T\&D\ Loss\ Adjustment = 1 + (\%\ of\ MA\ Average\ PV\ Production\ Weighted\ Losses)$

There is a great deal of uncertainty in the ultimate cost of this transmission in total and per-unit (depending on whether transmission is loaded lightly at wind capacity factors or more heavily with a wind/hydro blend), as well as the degree to which such costs would be allocated to network transmission customers. As a result, this value is estimated parametrically. The base assumption was developed by SEA for other projects as a middle-of-the-range value, as described further in Appendix A in the discussion of parametric values assumptions.

Table 108: Avoided Transmission Investment - Remote Wind Impacts by Perspective

Policy	Participants		Non-participating Ratepayers	Citizens of MA at Large
	Non-Owner Participants	Customer-generator (CG)		
SREC, A & B	n/a	[1]	Avoided Share of network TX costs allocated to load	Avoided Share of network TX costs allocated to load
Notes:	[1] Since T rates would go down (relative to no solar policy), there would be some lost NMC benefit, but this is second-order and ignored			

D.8.2 Avoided Transmission Investment – Local

Avoided local transmission investment comprises the costs avoided by solar PV inasmuch as it allows an EDC to defer *(or* defer to the point *of* avoiding) investments intended to upgrade local transmission or sub-transmission systems.

When solar PV is installed near load, some of it will contribute to changes in EDC planning, such that some local transmission upgrade investments will be *deferred*, potentially for many years (in some cases equivalent to *avoiding* the investment), that otherwise would have been needed to provide additional capacity to meet peak growth. This deferral value is, in fact, location-specific, but can be estimated on average over EDC service territory.

The estimates of **capital costs** and deferral benefits associated with solar PV contained in this analysis are taken from literature review, and adjusted to be comparable by applying MA- and PV-specific factors discussed in Section 3.1. The active benefits derived from this literature review are site-specific, and all deferral benefits are a function of growth, and technical means may be required to achieve the deferral effect in local transmission planning. Extrapolating net present value of the benefit from site-specific deferral values across a EDC territory can be stated as:

$$NPV_{EDC\ Territory} = (Avoided\ Transmission * \%\ of\ Transmission\ Areas\ with\ Load\ Growth * \%\ of\ PV\ Dependable\ Capacity)$$

In this case, "dependable capacity" includes the use of physical assurance, storage, smart inverters with ride-through, linked DR and/or other means of ensuring the capacity benefits of PV. These benefits have been adjusted upward to reflect the impact of avoided peak demand line losses, as described in Section 3.2, and are assumed to be the same across all policy futures. The resulting values use the case-specific peak impact values calculated in Section 3.1 for each year.

Table 109: Avoided Transmission Investment – Local Impacts by Perspective

Policy	Participants		Non-participating Ratepayers	Citizens of MA at Large
	Non-Owner Participants	Customer-generator (CG)		
SREC, A, B	n/a	n/a	Costs deferred or avoided [1]	Costs deferred or avoided [1]
Notes:	[1] This benefit/kWh each year = (Revenue requirements for average **local transmission** upgrade capital cost ($/kW-yr) * Deferral savings as X% of upgrade cost * Solar ELCC/DCP as Y% of solar kW) / penetration of all distributed kW as Z% of upgrade kW			

D.8.3 Avoided Distribution Investment

Avoided distribution investment is the total cost that solar PV allows an EDC to defer *(or* defer to the point *of* avoiding) investments intended to upgrade local primary and secondary distribution systems. When solar PV installed near load, some of it will contribute to changes in EDC planning, such that some upgrade investments will be deferred, potentially for many years (in some cases equivalent to *avoiding* the investment), that otherwise would have been needed to provide additional capacity to meet peak growth. This deferral or effective avoidance can either be active or passive in nature.

For Active Distribution Deferral, the Avoided Distribution Investment methodology for this study had five main steps:

- First, estimates of deferral benefits were taken from a literature review. Seven sources were selected to represent a reasonable range of conditions and methodologies, and an average value was calculated from these sources for the area-wide passive deferral benefit of solar PV, as described more fully in Appendix E.[107] These sources included three case studies of active deferral in particular New England locations and four reports with estimates of passive or area-wide deferral impacts and with adequate detail on their methodologies. Where necessary, the estimates from four of these sources were adjusted to be comparable by applying MA-specific and PV-specific factors.
- Second, to confirm the reasonableness of the average distribution deferral value from the literature, that value was compared against a simplified analysis driven by assumptions about distribution feeder load growth, upgrade costs, solar penetration and coincidence of solar output with feeder load.
- Third, the analysis assumes that the percentage of the state's distribution system to which estimates of "active deferral" are applicable; this is the portion of the system that is growing and so will require new capacity or otherwise provides opportunities to defer distribution investments, estimated to be 30%.[108] This was applied to estimates from the literature review to the simplified analysis in Step 2 to get statewide values.[109]

Thus, the total active deferral benefits of a 100% peak coincident resource are the net present value of:

$$NPV_{EDC}(Active\ Dist.\ Deferral) = \frac{Distribution\ Deferral\ Value\ (\$/MWh)}{(Total\ PV\ MWac\ Causing\ Deferral) * Production\ Hours}$$

where

$$PV\ Causing\ Deferral = \left(\frac{Solar\ PV\ Capacity\ Causing\ Deferral}{ELCC\ (or\ Distribution\ Congestion\ Price, if\ Available)}\right)$$

However, if distributed solar PV is installed without integration into planning, the net deferral or avoidance benefits accrue in a rather different manner. While current utility planning assumes limited to no distribution

[107] These sources are listed in Appendix E, along with their URLs. Some of them were also referenced in "Review Of Solar PV Benefit & Cost Studies," 2nd Edition, Rocky Mountain Institute, September 2013 (www.rmi.org/elab_emPower), pages 31-34.
[108] For portions of the distribution system on which there is literally no load growth, there is essentially no deferral opportunity for DER. However, the deferral benefit is at its highest with load growth around ½ of 1 percent/year, other things being equal, since DER (at an assumed 10% penetration) can not only defer the upgrade but avoid it for an entire 30-year period.
[109] The average values used in this report will not be representative of any particular location.

deferral or avoidance benefit associated with PV in the short run, it can be assumed that over time, localized distribution planning (or the existence of distribution congestion pricing, if applicable) will take the solar into account in advance, leading to a "passive" deferral value that may be quantifiable in the future. While the passive value cannot currently be calculated on a locational basis without similar location-specific deferral values at many smaller, distribution-level nodes (often known as "buses") the analysis calculates the total deferral value (including an estimate of passive deferral value) that can currently be averaged across each EDC service territory.

- Thus, the fourth and penultimate step is to account for a number of factors that may be required in order for distribution planners to sufficiently rely upon solar DG to actually achieve a deferral of upgrade investments. To do this, the analysis results include a factor of 50% for the percentage of PV that can be counted upon for distribution deferral through the use of physical assurance, storage, smart inverters with ride-through, linked demand response and/or other means.
- The final step is to account for the estimated PV contribution at times of local system peak (the Est % of Dependable PV Capacity from the formula below).

Total Distribution Deferral Value: Thus, the formula for calculating the benefits of both active and passive deferral, as derived from a literature review of Massachusetts- and PV-specific values from is the net present value of:

$$NPV_{EDC}\,(Total\ Dist.Deferral) = \frac{\begin{pmatrix}((Modeled\ Deferral\ Value\ \$/MWh * 50\%) + (LitReview\ Deferral\ Value * 50\%\,)) * \\ Est\ \%\ of\ System\ with\ Load\ Growth * Est\ \%\ of\ Dependable\ PV\ Capacity\end{pmatrix}}{(1 - \%\ Average\ MA\ Line\ Losses)}$$

where

$$\%\ of\ System\ with\ Load\ Growth = 30\%$$

and

$$Est.\%\ of\ Dependable\ PV\ Capacity = 50\%$$

Table 110: Avoided Distribution Investment Impacts by Perspective

Policy	Participants		Non-participating Ratepayers	Citizens of MA at Large
	Non-Owner Participants	Customer-generator (CG)		
SREC, A, B	n/a	n/a	Costs deferred or avoided	Costs deferred or avoided
Notes:	Assume integration costs are internalized in charges to PV generators			

D.8.4 Avoided Natural Gas Pipeline

Avoided natural gas pipeline costs include the costs associated with building natural gas pipeline infrastructure to serve natural gas-fired generation that may be avoided by solar PV resulting from the deferral or avoidance of a new gas-fired generating unit.

When new natural gas-fired power plants are built or add to their capacity, added pipeline capacity to serve those plants may be needed (and under current pipeline-constrained conditions in New England, this can be assumed to be the case).

While solar has a lower capacity value during winter peak electricity (which coincides roughly with peak annual gas demand), increased PV capacity can potentially reduce total investment in gas pipeline capacity. These effects could be accentuated as technologies evolve to optimize PV's dependable capacity.

However, in part because capacity that leverages the Solar Carve-Out is generally assumed to replace wind, these benefits are outside the scope of the analysis, and are largely speculative at this juncture. While they are not quantified in this analysis, the associated avoided cost value related to PV would apply in the future if the cost of building future pipeline capacity is built into electricity prices and the amount of pipeline capacity needed reflected the (modest winter) contribution of solar to reducing winter energy demand.

Table 111: Avoided Natural Gas Pipeline Impacts by Perspective

Policy	Participants		Non-participating Ratepayers	Citizens of MA at Large
	Non-Owner Participants	Customer-generator (CG)		
SREC, A & B	n/a	n/a	*Reduced cost of NG Pipeline in ISO Tariff*	*Reduced cost of NG Pipeline in ISO Tariff*
Notes:				

D.9 Category VII: Externalities and Other

The final major category of costs and benefits considered in this analysis are associated with the costs associated with avoided external costs and other costs to society pertaining to PV systems eligible for net metering. The five subcategories of costs and benefits contained within externalities and other costs include:

Avoided Environmental Costs CO_2, NO_x and SO_x	CB7.1	Quantitative
Avoided Fuel Uncertainty	CB7.2	*Qualitative*
Resiliency	CB7.3	*Qualitative*
Impact on Jobs	CB7.4	*Qualitative*
Policy Transition Frictional Costs	CB7.5	*Qualitative*

It is important to note that these values tend to vary with the amount of solar PV installed and producing. The table below illustrates the cost and benefit subcategories within this category accruing (on net) to each perspective.

Table 112: Externalities and Other Impacts Applicability to Analysis Perspectives

Perspective	Subcategories Accruing as Benefits	Subcategories Accruing as Costs
*Non-Owner Participants **(NOP)***	- N/A	- Policy Transition Frictional Costs [1]
*Customer-Generators **(CG)***	- Avoided Fuel Uncertainty [1]	- Policy Transition Frictional Costs [1]
*Non-Participating Ratepayers **(NPR)***	- Avoided Environmental Impacts	- Policy Transition Frictional Costs [1]
*Citizens of the Commonwealth at Large **(CC@L)***	- Avoided Environmental Impacts - Avoided Fuel Uncertainty [1] [3] - Resiliency [1] [3] - Impact on Jobs [1] [3]	- Policy Transition Frictional Costs [1] - Impact on Jobs [1] [2] - Resiliency [1] [2]

[1] Explored qualitatively
[2] (Qualitative) potential cost component
[3] (Qualitative) potential benefit component

D.9.1 Avoided Environmental Costs (CO_2, SO_x and NO_x)

Avoided environmental costs include the costs (both priced and not priced) of environmental damage associated with the emission of carbon dioxide (CO_2), sulfur dioxide (SO_x) and nitrogen oxides (NO_x) electricity generation utilizing fossil fuels.

To account for these avoided external environmental costs, the analysis, which includes analysis of scenarios assuming both full (and partial) compliance with Class I RECs assumes that each ton of CO_2, NO_x & SO_x abated by solar PV production avoids the equivalent net social cost of emitting each ton of these pollutants. The net social cost per ton avoided is represented by the difference between the societal value of the environmental damage and the already internalized market price of the emissions avoided by PV production. The quantities of avoided emissions were modeled through the AURORA dispatch analysis, which can account for added or avoided natural gas generation. The derivation of the societal value of avoided emissions uses standard methodologies used by US EPA, and are discussed further in Appendix A.

Table 113: Avoided Environmental Costs CO_2, NO_x and SO_x Impacts by Perspective

Policy	Participants		Non-participating Ratepayers	Citizens of MA at Large
	Non-Owner Participants	Customer-generator (CG)		
SREC, A, B	n/a	n/a	**Net impact (+ or -) of shift between solar and wind (or natural gas) [1,2]**	**Net impact (+ or -) of shift between solar and wind (or natural gas) [1,2]**
Notes:	[1] Avoided cost each year = net change (tons/yr) * [societal cost – market price ($/ton)] **[2] This will be loss adjusted using production wtd energy loss factor**			

D.9.2 Avoided Fuel Uncertainty

Avoided fuel uncertainty accounts for the costs associated with the risk of a significant change in the price of fuels for electricity generation (specifically natural gas) and the associated costs of fuel hedging contracts and other instruments that can be avoided by solar PV deployment. In the case of solar PV, the value of avoided fuel cost uncertainty would capture the value of price-certain resource compared to a price-uncertain resource. While quantitative analysis of this value is beyond the scope of this study, the factor was recently included in Maine's Value of Solar Study (Clean Power

Research, LLC; Sustainable Energy Advantage, LLC; Perez Richard; Pace Law School Energy and Climate Center, 2015) released in March 2015. The Maine VOSS quantified this value to be $0.037/kWh (on a 25-year levelized basis) at by estimating the cost associated with eliminating long term price uncertainty with procuring the quantity of natural gas displaced by solar PV. To do this, the authors of that analysis calculated the difference between the non-guaranteed and guaranteed price of natural gas to determine the net present value of hedging natural gas purchases. Thus, it appears that this methodology could be utilized in Massachusetts and could represent a significant value in Massachusetts. We have not, however, included this value within this analysis.

Table 114: Avoided Fuel Price Uncertainty Impacts by Perspective

Policy	Participants		Non-participating Ratepayers	Citizens of MA at Large
	Non-Owner Participants	Customer-generator (CG)		
SREC	*3PO: all, assuming (to simplify) that 100% of deals are at a fixed price or fixed discoint with floor [1]*	*HO: all consumed on site or rolled forward or net metered* *No value for any generation sold at W/S, which includes generation not consumed on-site post NM caps*	**n/a**	*Sum of participants*
A, B	*Complex?*	*Complex?*	*value for any generation sold at W/S, which includes generation not consumed on-site post NM caps*	*Value * all production?*
Notes:	[1] simplified representation, ignores % discount deals which would lose this benefit			

D.9.3 Resiliency

Resiliency describes the broad category of benefits solar could provide, if accompanied by storage, as a beneficial ancillary service to the utility grid. Sector A in the current SREC-II program Sector A includes "Emergency Power Generation Units", but the benefits of these units (and their broader deployment during an emergency situation) is not yet readily quantifiable. The ability to provide emergency ancillary services benefits, however, could provide significant situational value, and is thus discussed qualitatively in greater depth in Section 9.2. However, the net benefits will depend on the level of increased costs needed to create resiliency benefits.

Table 115: Resiliancy Impacts by Perspective

Policy	Participants		Non-participating Ratepayers	Citizens of MA at Large
	Non-Owner Participants	Customer-generator (CG)		
SREC, A, B	n/a	*Additional Cost for resiliency features* *Host receives resiliency benefits*	n/a	*Resiliency benefits less costs*
Notes:				

D.9.4 Impact on Jobs

Job impacts associated with solar PV include the jobs gained and lost as a result of an increased (or decreased) rate of solar PV deployment. The deployment of solar PV affects overall employment in Massachusetts in three distinct ways: 1) through the in-state proportion of added jobs driven by solar installations and related supply chain (including, where applicable, manufacturing), 2) the potential loss of jobs in the wind sector associated with greater solar capacity (but which largely occurs out of state), and 3) the impact on employment from increased ratepayer costs resulting from any premium paid by those citizens, which is impacted by the share of revenue that would be spent in Massachusetts. While quantitative analysis of this issue is beyond the scope of this study, the impact on jobs is likely to differ between policies, and is explored in Section 9.1.

D.9.5 Cost-Benefit Impacts by Perspective

Table 116: Impact on Jobs Impacts by Perspective

Policy	Participants		Non-participating Ratepayers	Citizens of MA at Large
	Non-Owner Participants	Customer-generator (CG)		
SREC, A, B	n/a	n/a	n/a	*Direct solar and related jobs added* *Job losses due to redirected spending of solar premiums* *Indirect Macroeconomic impacts*
Notes:	Beyond scope; Potential area for further study			

D.9.6 Policy Transition Frictional Costs

The "frictional" costs associated with a broad-scale policy transition refer to the potentially significant (but difficult to quantify) costs to solar market stakeholders and other participants associated with broad-scale solar policy change. The issue of the *ex post* costs to current market participants associated with policy friction was raised by stakeholders in interviews and at meetings of the Task Force. Indeed, these conversations have revealed the fears of customer-generators, investors, market-makers, and other market participants of the "substantial" costs cited as potential impact of transition to these parties from one policy regime to another. In fact, several stakeholders in Group F suggested this could be reflected as an increased cost of financing and departure of investors from markets, as well as layoffs if the market pauses as a result of policy uncertainty. Specifically, one investor in this group suggested that impact could be modeled as a 300-400 basis point increase in cost of capital (in some cases), while a lender indicated that investors tend to discount revenues that are more uncertain, thus increasing the cost of financing.

One approach to mitigate this uncertainty suggested by certain members of the Task Force could be to design in longer lead times prior to change in the policy regime in order to allow time to adapt), particularly with respect to existing deals in the project and financing pipeline.

It is foreseeable that an entirely separate set of *ex post* costs and benefits will accrue as a result of policy friction, and may ultimately be substantial. However, it is exceedingly difficult to account for the uncertain *ex post* nature of these impacts unique to the policy future selected (or variation thereof) in the absence of reliable comparisons on an *ex ante* basis. As such, while it is important for these costs to be considered further (and potentially quantified as part of any further analysis), quantitative analysis of the costs and benefits associated with friction is not a component of this analysis.

Table 117: Policy Transition Frictional Costs Impacts by Perspective

Policy	Participants		Non-participating Ratepayers	Citizens of MA at Large
	Non-Owner Participants	Customer-generator (CG)		
Any transition could trigger...	*Loss of savings capture due to increased costs*	*Increased costs due to increase in uncertainty*	*Higher compliance costs*	*Job losses*
Notes:				

APPENDIX E: BACKGROUND ON AVOIDED DISTRIBUTION INVESTMENT

The Avoided Distribution Investment component was described as follows in Appendix D:

- When solar PV is installed near load, some of it will contribute to changes in EDC planning, such that some upgrade investments will be deferred[110] that otherwise would have been needed to provide additional capacity to meet peak growth; this is referred to as "active" deferral and applies to a subset of distribution area(s).
- In contrast, when solar PV is installed without integration into planning, there may be no deferral benefit in the short run, but over time it can nevertheless be assumed that, with experience, planning will take the solar into account, explicitly or implicitly, and this will lead to a "passive" deferral.
- Active and passive deferrals are estimated on the average and combined for the state.[111]

The Avoided Distribution Investment component represented a benefit to two of the four perspectives in this analysis: Non-Participating Ratepayers and Citizens at Large, as summarized in the following table:

Policy	Participants		Non-participating Ratepayers	Citizens of MA at Large
	Non-Owner Participants	Customer-generator (CG)		
SREC, A, B	n/a	n/a	Costs deferred or avoided	Costs deferred or avoided
Notes:	Assume integration costs are internalized in charges to PV generators			

The Avoided Distribution Investment methodology for this study had four main steps. The approach and assumptions are summarized below for each step.

Step 1: Literature Review

First, estimates of deferral benefits were taken from a literature review.

The following documents attempt to provide an overview of methodologies that have been and/or should be used to estimate the benefits and costs of solar PV for the T&D systems:

- A Regulator's Guidebook: Calculating the Benefits and Costs of Distributed Solar Generation, Interstate Renewable Energy Council, Inc., 2013, pages 26-30;
- Review Of Solar PV Benefit & Cost Studies, 2nd Edition, Rocky Mountain Institute, September 2013 (www.rmi.org/elab_emPower), pages 31-34.
- Minnesota Value of Solar: Methodology, Minnesota Department of Commerce, Division of Energy Resources, by Clean Power Research, April 9, 2014, pages 31, 36, 41.

These methodologies distinguish between T&D capacity benefits and "grid support" impacts. For present purposes, while grid support benefits and costs may become increasingly important over time,

[110] The deferral may last for many years in some cases, particularly where load growth is slow and the DER penetration is substantial, such that in present value terms the "deferral" is equivalent to "avoiding" most of the investment. See note 3.
[111] In addition to deferral of capacity investments, solar PV may have other grid support benefits, such as frequency and voltage regulation. There may also be grid integration costs that are not internalized through the interconnection process. These are complex subjects with changing technologies and rules, but for present purposes, these were not quantified and may be assumed to largely offset each other.

we do not attempt to quantify them here, since there is little information available with which reliable estimates could be made for Massachusetts. We also assume that, to the extent solar interconnection and integration costs are incurred that are not internalized in the cash flows of solar owners, they are offset by grid support benefits.[112] Therefore, T&D capacity benefits are the only T&D benefits that are quantified in this report.

It is widely accepted that, under certain conditions, solar PV may contribute to economic savings by deferring the need to upgrade certain elements of the T&D system. The primary basis for the estimates of deferral benefits used in the present report is a set of economic values reported for case studies and planning studies that are publicly available. Specifically, the following seven sources provide a representative range of estimates.

1. "DG and Distribution Planning: An Economic Analysis for the Massachusetts DG Collaborative," Navigant Consulting, Attachment G to Report to DPU, Jan. 2006
2. "2014 System Reliability Procurement Report," The Narragansett Electric Company d/b/a National Grid, R.I.P.U.C. Docket No. 4453
3. Grid Solar Boothbay: Order Approving Stipulation, State of Maine Public Utilities Commission Docket No. 2011-138, April 30, 2012, Request for Approval of Non-Transmission Alternative (NTA) Pilot Projects for the Mid-Coast and Portland Areas
4. "The Value of Distributed Photovoltaics to Austin Energy and the City of Austin," Clean Power Research, L.L.C., March 17, 2006
5. "The Value of Distributed Solar Electric Generation to New Jersey and Pennsylvania," for Mid-Atlantic Solar Energy Industries Association & Pennsylvania Solar Energy Industries Association, by Perez, Norris & Hoff, Clean Power Research
6. "The Benefits and Costs of Solar Distributed Generation for Arizona Public Service," by Beach & McGuire, Crossborder Energy, May 8, 2013
7. "Evaluating the Benefits and Costs of Net Energy Metering in CA," prepared for The Vote Solar Initiative, Crossborder Energy, January 2013.

The following table compares the most relevant estimates from these seven sources, and shows their average value: $.016/kWh.

[112] This report has not addressed any possible differences between the Policy Paths in the ability to optimize these unquantified costs and benefits, such as by targeting feeders or other locations with relatively low interconnection costs for solar projects or with relatively high grid support benefits.

		Key Metrics from Literature Review		A	B	C	D	E
				T&D Capacity Value (2015 dollars)		Deferral Benefit from PV with Specified DCP (2015 dollars)		
				Potential Deferral		Active Deferral		Statewide
				$/kW or $/kVa	$/kW-year (not PV)	$/kW-year of PV	$/kWh of PV	$/kWh of PV
				Blue= source value Green= calculated value using assumptions as needed				
1	MA	DG and Distribution Planning: An Economic Analysis for the Massachusetts DG Collaborative, Navigant Consulting, Attachment G to Report to DPU, Jan. 2006	2006	$35	$5	$8	$0.007	$0.002
2	RI	2014 System Reliability Procurement Report, The Narragansett Electric Company d/b/a National Grid, R.I.P.U.C. Docket No. 4453	2014			$49	$0.038	$0.012
3	ME	Grid Solar Boothbay: Order Approving Stipulation, 2012	2012			$281	$0.220	$0.066
4	TX	The Value of Distributed Photovoltaics to Austin Energy and the City of Austin, Clean Power Research, L.L.C., March 17, 2006	2006	$1,516	$64	$31	$0.025	$0.007
5	NJ & PA	The Value of Distributed Solar Electric Generation to New Jersey and Pennsylvania, for Mid-Atlantic Solar Energy Industries Association & Pennsylvania Solar Energy Industries Association, by Perez, Norris & Hoff, Clean Power Research	2012					$0.003
6	AZ	The Benefits and Costs of Solar Distributed Generation for Arizona Public Service, by Beach & McGuire, Crossborder Energy, May 8, 2013	2013					$0.002
7	CA	Evaluating the Benefits and Costs of Net Energy Metering in CA, prepared for The Vote Solar Initiative, Crossborder Energy, January 2013	2012		$55 (SCE) $77 (SDG&E) ~$80 (PG&E)			$0.022
							Average of values above	$0.016

One other study appeared too late to add into this average: "Value of Distributed Generation, Solar PV in Massachusetts," Acadia Center, April 2015. Its estimate of statewide deferral value for south-facing solar in Massachusetts -- $.018/kWh -- was only slightly above the average of the seven sources above, so it wouldn't have significantly changed the result.

Other sources provided relevant estimates of distribution investments or capital costs that are potentially deferrable (e.g., load or capacity upgrades), but stopped short of estimating deferral impacts.

As can be seen from the table, the literature includes a wide range of estimates. Also, different metrics are reported that are often not directly comparable. Where necessary (see green values in table), values have been converted to comparable units of dollars per solar kW and cents per solar kWh, using assumptions for solar capacity factor (for column D) and ELCC (solar match, for column E) that are consistent with the rest of the present project. Values have also been adjusted to 2015 dollars, using a 2.5% annual escalator.

Step 2: Simplified Generic Worksheet of Distribution Deferral

To confirm the reasonableness of the $.016/kWh average distribution deferral value from the literature, that value was compared against a simplified generic worksheet driven by a basic set of assumptions about distribution feeder load growth, upgrade cost, solar penetration and coincidence of solar output with feeder load. This worksheet illustrates the range of potential deferral benefits as these assumptions are varied, and provides additional confidence in the deferral value from the literature in step 1. The following table illustrates a scenario with a deferral from 2018 to 2037, which leads to a 56% savings in the present value of distribution investment required. The assumptions that lead to this scenario are listed below.

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
				Upgrade cost incurred in year when needed							
		Load as % of Capacity		Year of Need for Upgrade		Cost of Upgrade ($000)	Capital Cost & Timing of Upgrades ($000)		Amortized Cost of Upgrades ($000), based on 30-year NPV		
		Existing	with DER	Existing	with DER		Upgrade, No DER	Upgrade, with DER	Upgrades, No DER	Upgrades with DER	Annual Savings ($000)
0	2015	98.0%	83.0%			$ 250			100%	44%	56%
1	2016	98.7%	83.7%	0	0	256	-	-	$ -	$ -	$ -
2	2017	99.5%	84.5%	0	0	263	-	-	$ -	$ -	$ -
3	2018	100.2%	85.2%	2018	0	269	269	-	$ 31	$ 14	$ 18
4	2019	101.0%	86.0%	0	0	276	-	-	$ 31	$ 14	$ 18
5	2020	101.7%	86.7%	0	0	283	-	-	$ 31	$ 14	$ 18
6	2021	102.5%	87.5%	0	0	290	-	-	$ 31	$ 14	$ 18
7	2022	103.3%	88.3%	0	0	297	-	-	$ 31	$ 14	$ 18
8	2023	104.0%	89.0%	0	0	305	-	-	$ 31	$ 14	$ 18
9	2024	104.8%	89.8%	0	0	312	-	-	$ 31	$ 14	$ 18
10	2025	105.6%	90.6%	0	0	320	-	-	$ 31	$ 14	$ 18
11	2026	106.4%	91.4%	0	0	328	-	-	$ 31	$ 14	$ 18
12	2027	107.2%	92.2%	0	0	336	-	-	$ 31	$ 14	$ 18
13	2028	108.0%	93.0%	0	0	345	-	-	$ 31	$ 14	$ 18
14	2029	108.8%	93.8%	0	0	353	-	-	$ 31	$ 14	$ 18
15	2030	109.6%	94.6%	0	0	362	-	-	$ 31	$ 14	$ 18
16	2031	110.4%	95.4%	0	0	371	-	-	$ 31	$ 14	$ 18
17	2032	111.3%	96.3%	0	0	380	-	-	$ 31	$ 14	$ 18
18	2033	112.1%	97.1%	0	0	390	-	-	$ 31	$ 14	$ 18
19	2034	112.9%	97.9%	0	0	400	-	-	$ 31	$ 14	$ 18
20	2035	113.8%	98.8%	0	0	410	-	-	$ 31	$ 14	$ 18
21	2036	114.6%	99.6%	0	0	420	-	-	$ 31	$ 14	$ 18
22	2037	115.5%	100.5%	0	2037	430	-	430	$ 31	$ 14	$ 18
23	2038	116.4%	101.4%	0	0	441	-	-	$ 31	$ 14	$ 18
24	2039	117.2%	102.2%	0	0	452	-	-	$ 31	$ 14	$ 18
25	2040	118.1%	103.1%	0	0	463	-	-	$ 31	$ 14	$ 18
26	2041	119.0%	104.0%	0	0	475	-	-	$ 31	$ 14	$ 18
27	2042	119.9%	104.9%	0	0	487	-	-	$ 31	$ 14	$ 18
28	2043	120.8%	105.8%	0	0	499	-	-	$ 31	$ 14	$ 18
29	2043	121.7%	106.7%	0	0	512	-	-	$ 31	$ 14	$ 18
30	2044	122.6%	107.6%	0	0	524	-	-	$ 31	$ 14	$ 18
				Sum			269	430	878	388	490
				Net Present Value			**235**	**104**	**356**	**157**	**199**
				Levelized Values					27	10	15
				Upgrade and Savings Percentages					**100%**	**44%**	**56%**

The assumptions which lead to this deferral from 2018 to 2037 are listed below, including a distribution feeder load growth rate of 0.75%/year, an upgrade cost of $250/kW, penetration of 15% for solar (or a combination of solar and other Distributed Energy Resources (DER), and coincidence of 33% between solar output and feeder load (equivalent to the ELCC, but at the distribution level; see Section 3.1 for a chart of this value over time). The following table also summarizes the results of this deferral scenario in present value terms:

- a 56% savings in the present value of distribution investment required, and
- a distribution deferral value of $.055/kWh for PV on this feeder (for "active deferral") from this simple model.[113]

Two additional calculations appear at the bottom of this table, which are described in Steps 3 and 4 below:

- a statewide (or "passive") distribution deferral value of $.016/kWh (which is nearly the same as the average from the literature in Step 1), after assuming (per Step 3 below) that 30% of the feeders statewide would have an opportunity for such an active deferral, and
- a net statewide distribution deferral value of $.008/kWh after assuming that deferral would be feasible on 50% of the feeders despite technical challenges discussed in Step 4 below.

Illustrative Model of Upgrade Deferral by DER (4/27/15)

Inputs: input cell

1	Feeder Capacity (MW)	1.0
2	Current Load %	98%
3	Current Load (MW)	1.0
4	Peak Load Growth	0.750%
5	New DER as % of Feeder Load	15.0%
6	DER Reduction of Load (MW)	0.147
7	Upgrade Cost/kW *	$ 250.00
8	Upgrade Capacity	100%
9	Upgrade Capacity (MW)	1.0
10	Cost ($000, $/kW-yr)	$250
11	Escalation of Upgrade Cost	2.5%
12	Discount Rate/WACC	7.0%
13	Carrying Chg/ Fixed Chg Rate (see sheet)	13.3%
14	Solar DCP (Distrib Contrib as % of PV kW)	33%
15	Solar MW (AC)	0.445
16	Solar MWh/yr	567
17	Deferral years	19
18	MWh in deferal years	10,771

Results:

	Capital Costs		Annual Costs	
	Upgrade, No DER	Upgrade, with DER	Upgrade, No DER	Upgrade, with DER
Present Value Analysis:				
Upgrade Cost ($000)	$ 220	$ 97	$ 333	$ 147
Savings ($000)		$ 123		$ 186
Savings (% reduction)		56%		56%
Savings $/kW of DER		$ 834		$ 1,262
Savings $/kW of Solar		$ 275		$ 1,043

	This Run	Weighted*
Cumulative Savings $/kWh of Solar	$ 0.0617	$ 0.0548

** Weighted by load growth and DER penetration*

	Active	% of load on feeders with growth	Statewide
Distribution Deferral for PV across territory from model ($/kWh)	$ 0.0548	30%	$ 0.0164
Average of 5 values from the literature ($/kWh)	$ 0.0542	30%	$ 0.0163
Weighted/selected results	$ 0.0542		$ 0.0163
Adjustment for technical issues			50%
Assumed Distribution Deferral for PV ($/kWh)			$ 0.0081

Step 3: Opportunities to Defer Distribution Investments

113 The amortized Annual Savings in column (10) are divided by the cumulative solar kW installed each year to defer the investment, and then the resulting $/kW annual savings are divided by solar output each year and levelized for this active deferral value of $.055/kWh.

We make an assumption for the percentage of the state's distribution system to which estimates of "active deferral" are applicable; this is the portion of the system that is growing and so will require new capacity or otherwise provides opportunities to defer distribution investments.[114] We have used 30 percent as a placeholder assumption for this factor. This was applied to estimates from four of the literature sources and to the results from the worksheet in Step 2 to get a statewide distribution deferral value of $.016/kWh.[115]

Step 4: Technical Factors to Achieve Deferral

There are a number of factors that may be required in order for distribution planners to sufficiently rely upon solar DG to actually achieve a deferral of upgrade investments. Some of these factors may affect the physical availability of PV to reduce load under challenging conditions, such as following power quality disturbances and grid outages; planning lead time is also a factor.

These factors include:

- IEEE 1547 standards requires DG to trip for low voltage and other disturbances, and low-voltage ride-through may be incompatible with anti-islanding protection;
- Planners can't count on PV to be on-line instantly as power is restored after outage; and,
- Physical assurance may be needed to keep load off the distribution system if the solar goes down.

These issues are important and should be addressed through further R&D, pilot testing and policy development. This will lead to better information to estimate their impact on the benefits and costs of solar for the T&D system. In the meantime, we simply apply a factor for the percentage of PV that can be counted upon for distribution deferral through the use of physical assurance, storage, smart inverters with ride-through, linked demand response and/or other means. We have used 50 percent as a placeholder assumption for this factor, resulting in a net statewide distribution deferral value of $.008/kWh.

Results

The result for steps 1 through 3 for this illustration was $.016 average statewide value of Avoided Distribution Investment per kWh of solar PV. After applying the 50% factor from Step 4, the net value = $.008/kWh. The modeling for this study replaced the static assumption for peak coincidence described above with the with the solar penetration-dependent value for each year, calculated as discussed in Section 3.1.

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[114] For portions of the distribution system on which there is literally no load growth, there is essentially no deferral opportunity for DER. However, the deferral benefit is at its highest with load growth around ½ of 1 percent/year, other things being equal, since DER (at an assumed 10% penetration) can not only defer the upgrade but avoid it for an entire 30-year period.
[115] The average values used in this report will not be representative of any particular location.