Clean Energy Standard Cost Study

May 4, 2016

Key Findings

Introduction

- The Clean Energy Standard Cost Study complements and advances the Clean Energy Standard Staff White Paper
- 50% renewable electricity by 2030 and maintain carbon savings from nuclear plants
- Builds on the State's nationally leading efforts
  - Reduce greenhouse gas emissions 40% by 2030 and 80% by 2050
  - Protect the health and safety of New Yorkers
  - Stimulate economic growth
- Examines the impact that key cost drivers can have on overall consumer bills

→ assist the PSC to design and implement a cost-effective Standard

Results Summary

- Even in this period of lower electricity prices due to historically low natural gas prices, New York can meet its clean energy targets with **less than a 1% impact on electricity bills** (or less than $1 per month for the typical residential customer)
- In the near-term, under base case assumptions
  - $1.3 billion public investment
  - Generation of emission-free electricity, which produces $3.1 billion in carbon benefits (based on the U.S. EPA Social Cost of Carbon as specified the Benefit-Cost Analysis Order)
  - Hence, the **net program impact is a benefit of $1.8 billion**

REV and the CES

- Alignment with Reforming the Energy Vision and the Clean Energy Fund
  - Reduce ratepayer collections over time
  - Reduce the costs of clean energy technologies
- REV will cause expansion of distributed resources and enable integration with the electric grid in a way that decreases system costs and facilitates renewable generation
- CES supports the development of a vibrant clean energy market and provides the scale and certainty necessary for broad competition that encourages private investment and reduces costs

Key Findings

- The conclusions based on analysis covering the period to 2023
  - Coincides with the timing of periodic reviews of the CES by the PSC
  - Recognizes projection extending to 2030 subject to significant uncertainty
- Costs depend on a number of key drivers, some directly influenced by New York State policy
  - Procurement structures: bundled PPAs vs REC only
  - Energy price and interest rate
  - A technology cost
  - Energy use
  - Federal tax credit

Key Findings, cont'd

- Balances cost impact and results in **significant net benefits** for all New Yorkers
- **Procurement structures** and the **total energy used** significantly impact cost and are factors that New York State can influence
- Future energy prices are **highly uncertain**, and are an important driver
- Interest rates and technology cost variability have a relatively small near-term impact
- Technology-neutral approach to structuring the CES Tiers is an appropriate design choice.
- Current federal tax credits significantly reduce the cost
- **Combination of low energy prices, low interest rates and available tax credits presents a favorable environment for near-term investment into renewables**

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Approach and Results

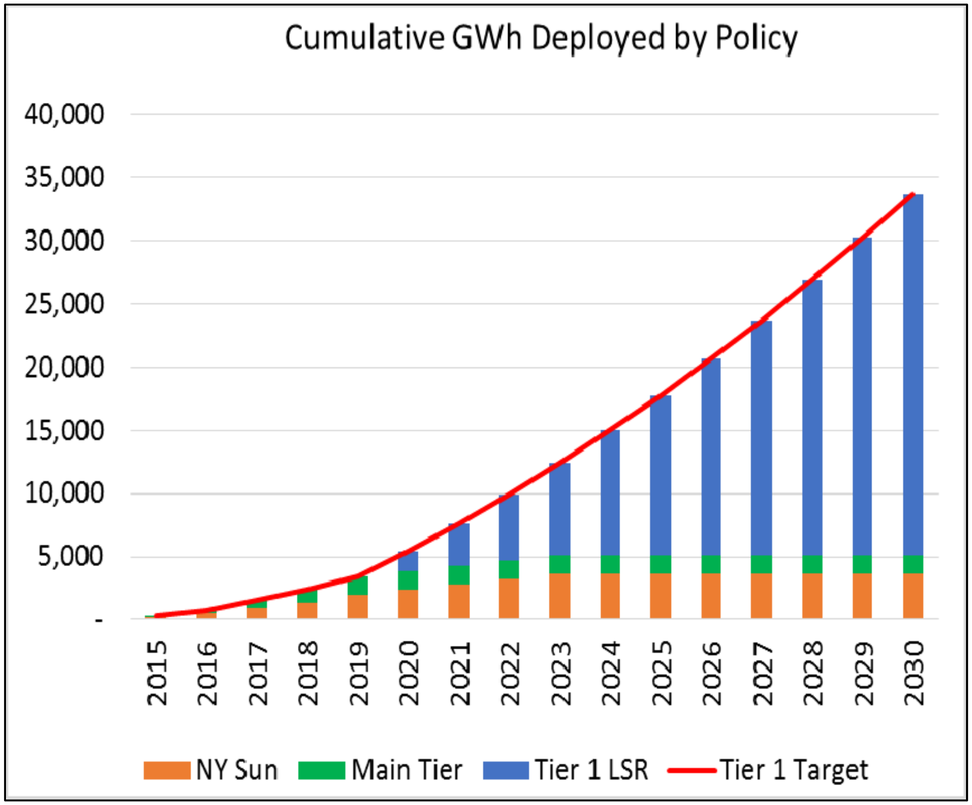
Clean Energy Standard - Structure

Tier	Purpose	Cost Study approach
Tier 1	Deploy new renewables	Analysis of procurement of least-cost NYS resource potential through auctions
Tier 2A	Maintain competitive legacy renewables	Analysis of forecast payments for renewables in New England
Tier 2B	Maintain non-competitive legacy renewables	Analysis based on historic compensation in other States
Tier 3	Maintain existing nuclear installations	Analysis of generation cost for nuclear

Cost Study - Indicators

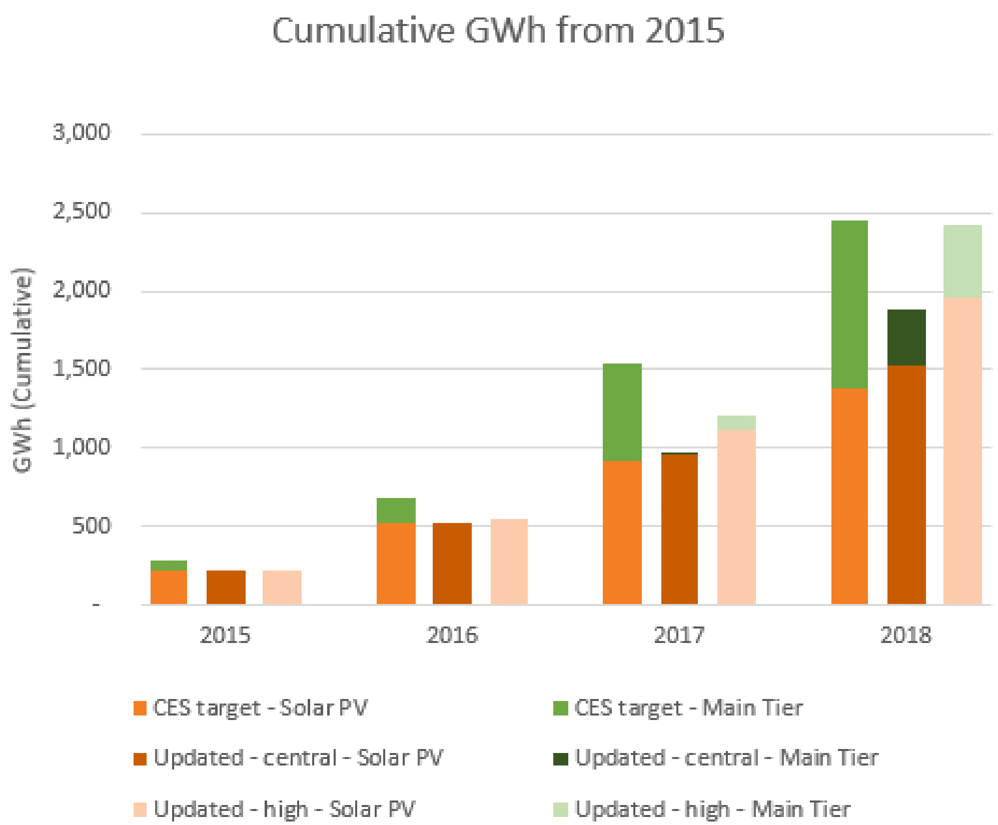
- Gross program cost, carbon benefit, net program cost
- 2023, 2030
- Annual cost and benefit, lifetime net present value, bill impact percentage
- Analysis carried out on base case and cost driver sensitivities including
    - procurement structures
    - energy prices
    - interest rates
    - technology costs
    - system load and
    - federal tax credits

Tier 1 by Program



- Indicative target trajectory
- Main Tier solicitations and NY Sun fulfil CES targets to 2019
- Analysis assumes 3 GW solar PV as per NY-Sun target

Updated Short-Term Projections

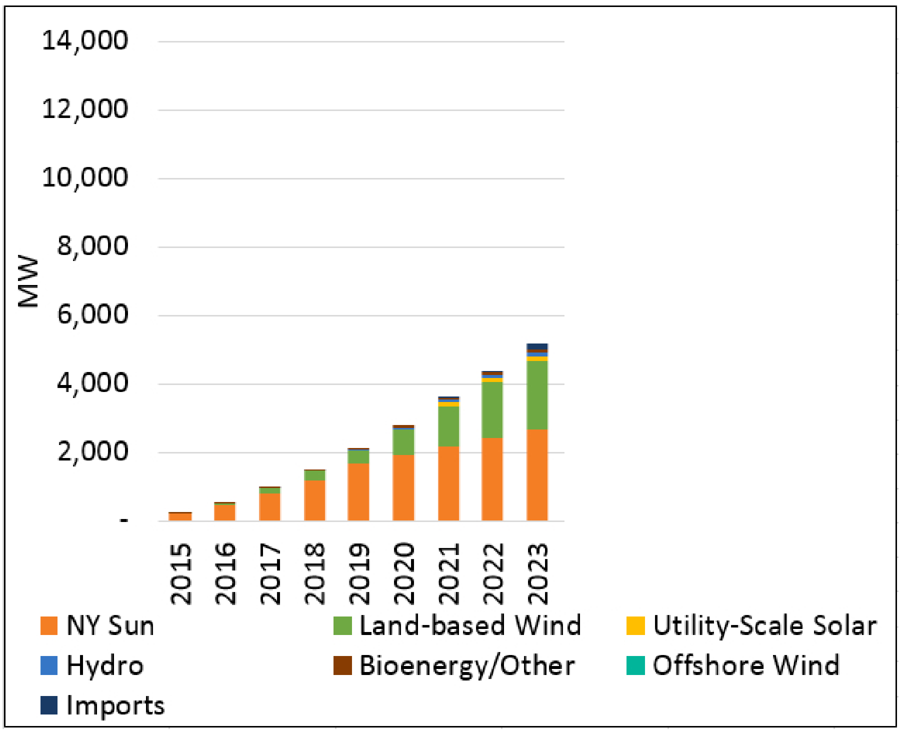


- The CES White Paper discusses policy options to reflect uncertainty on timing and quantity of new projects.
- The CES implementation process will make recommendations for PSC decision.

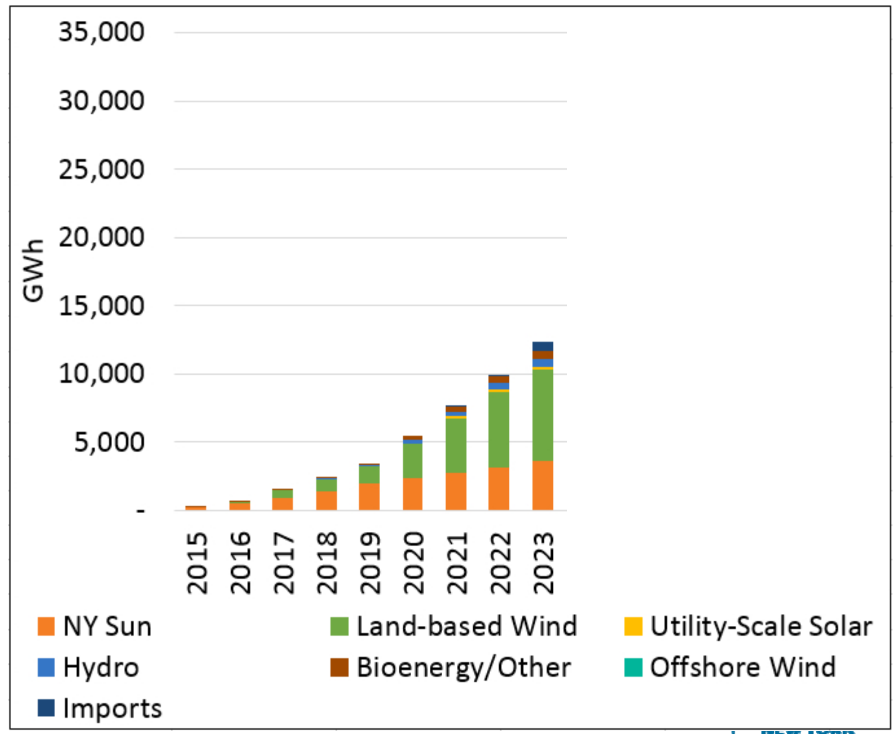
Updated BTM solar PV forecasts assume continued NEM and no interconnection constraints.

Tier 1 Base Case Technology Mix Projection

Capacity



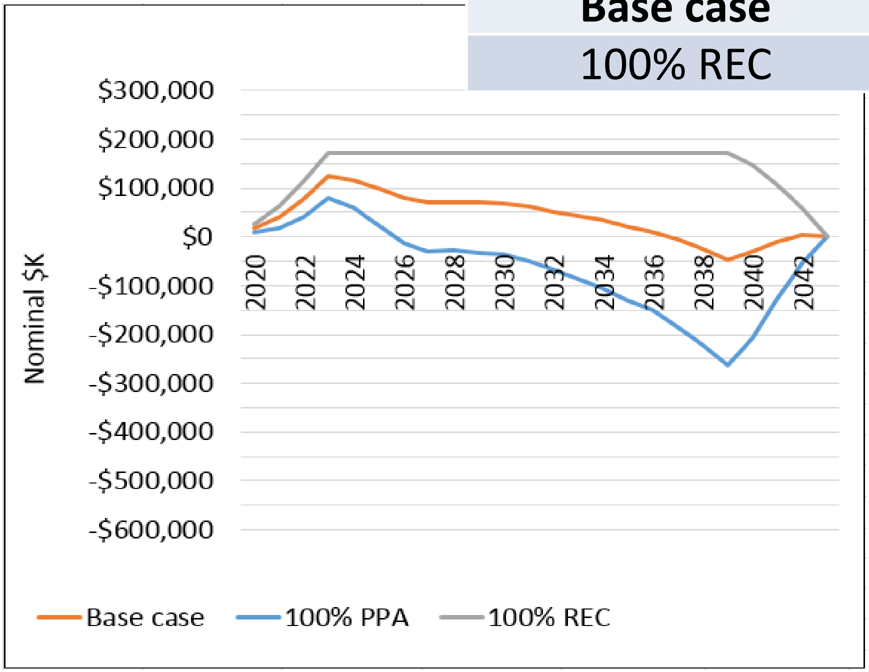
Generation



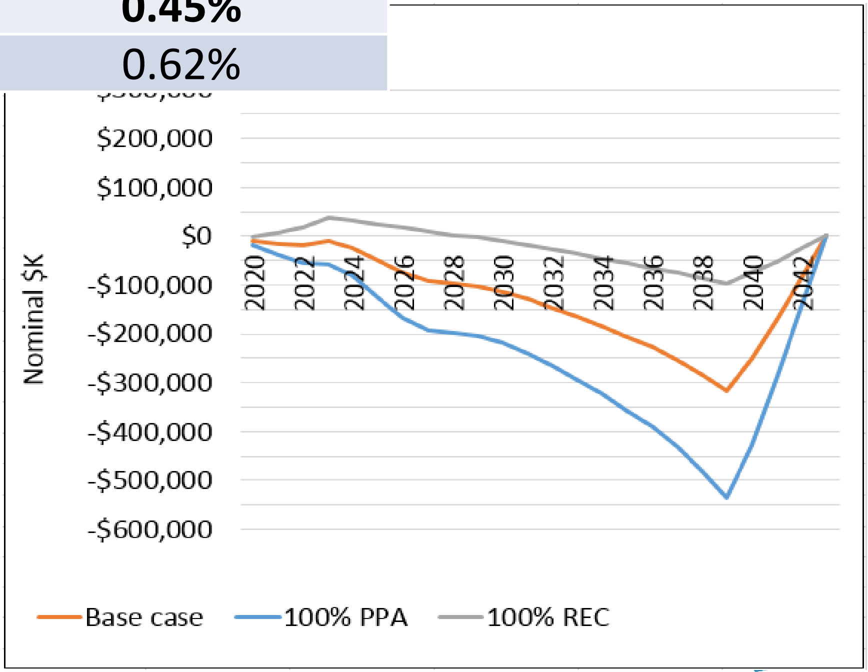
Tier 1 to 2023 – Procurement Structures

Tier 1 only	Bill impact in 2023
100% PPA	0.28%
Base case	**0.45%**
100% REC	0.62%

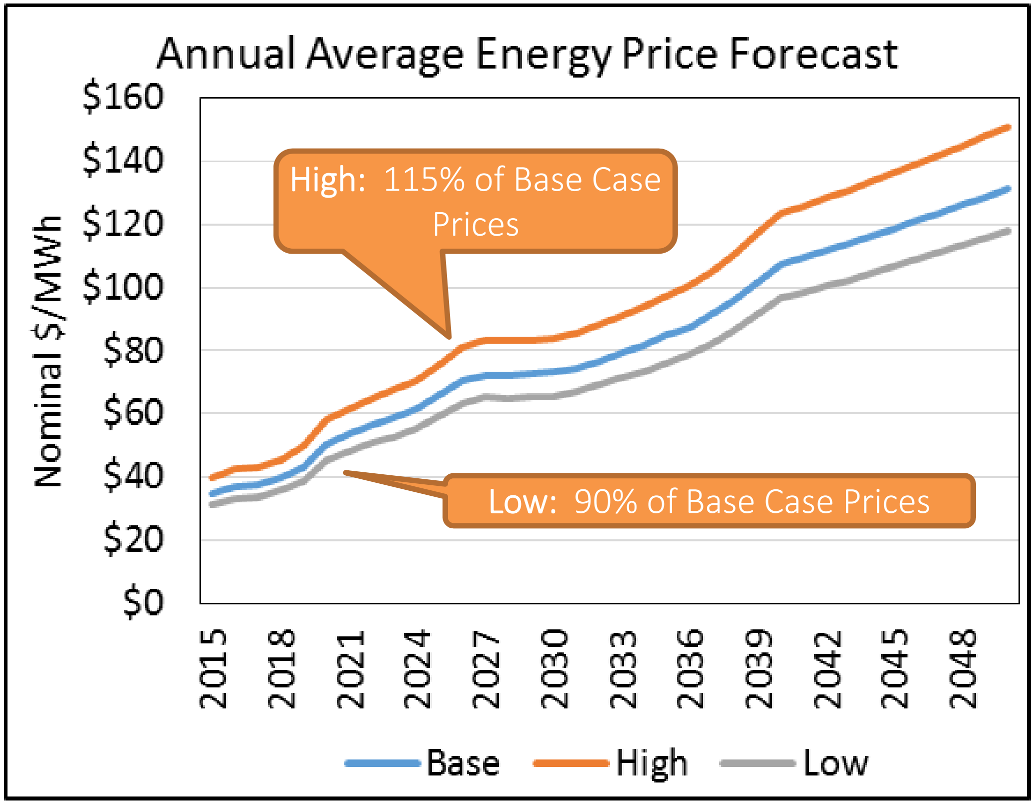
Gross Program Cost



Net Program Cost



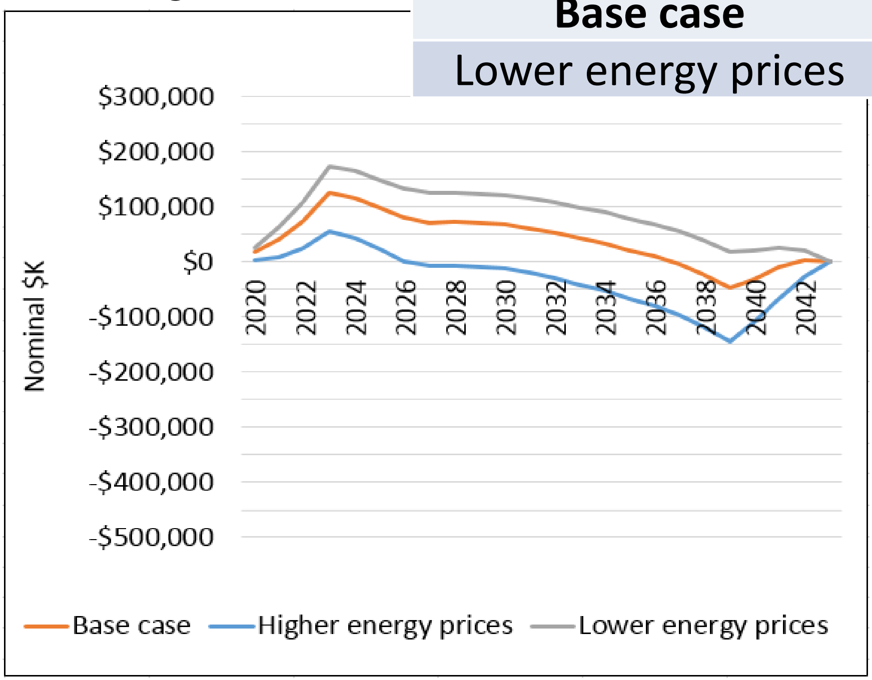
Energy Price Forecast Sensitivities



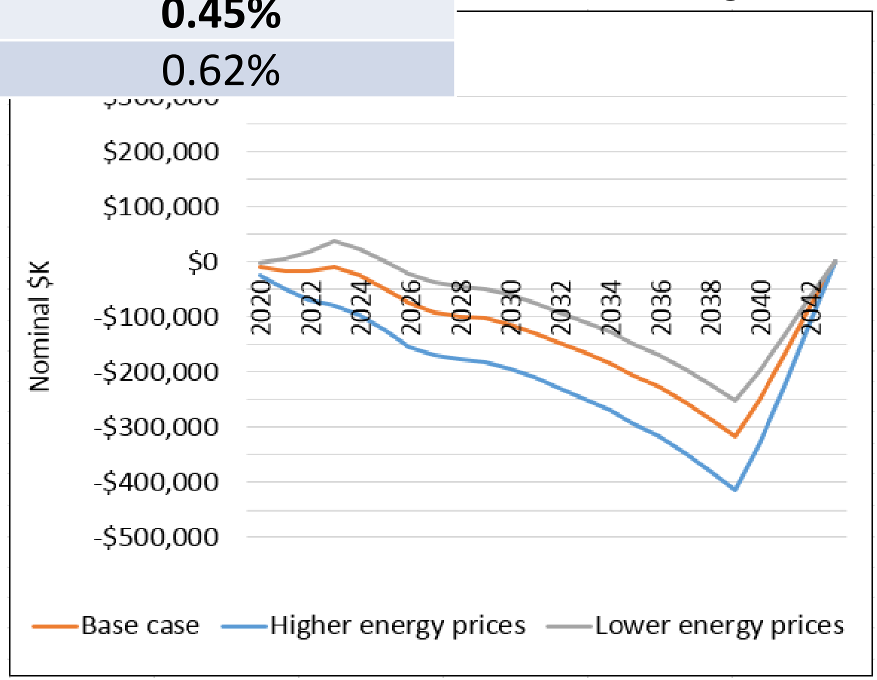
Tier 1 to 2023 – Energy Prices

Tier 1 only	Bill impact in 2023
Higher energy prices	0.20%
Base case	**0.45%**
Lower energy prices	0.62%

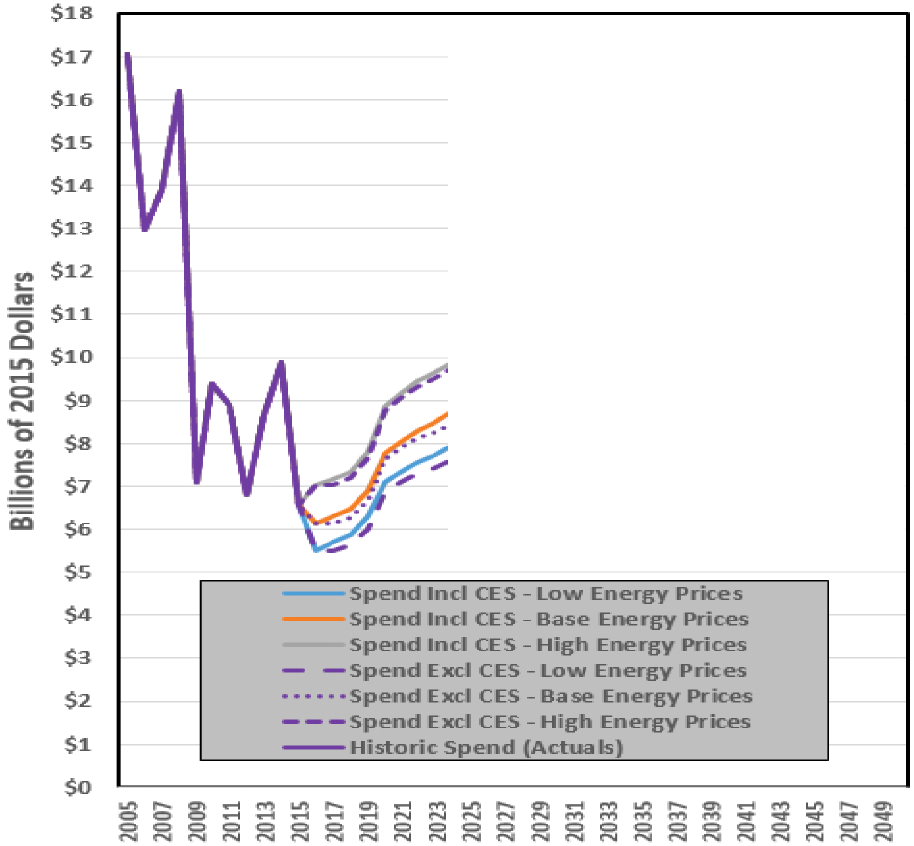
Gross Program Cost



Net Program Cost



Comparison with Forecast Wholesale Prices



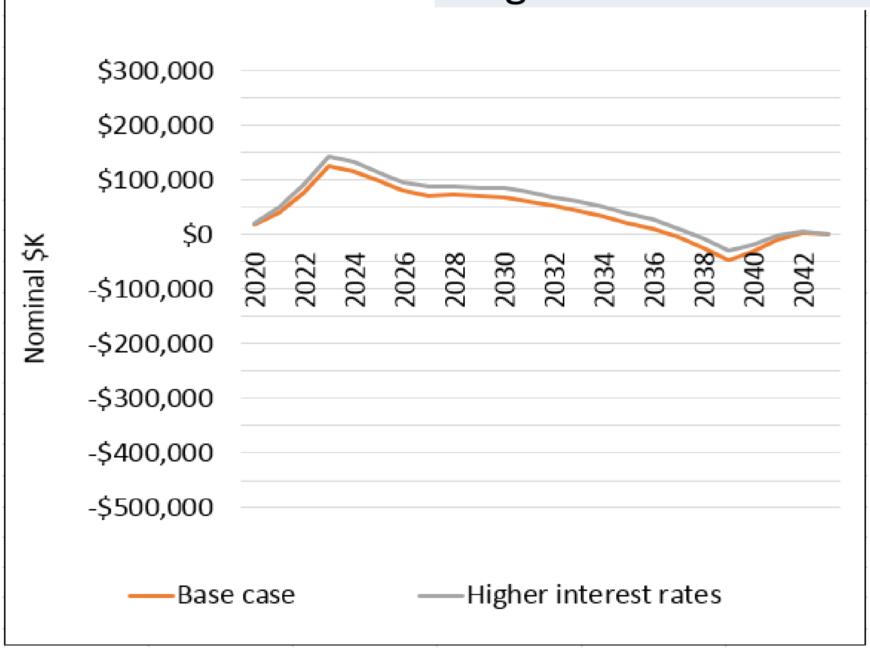
This shows historic and forecast wholesale energy spend as well as forecast total CES program cost.

While CES program costs would be higher under low energy prices, this would be outweighed by customers' savings on their overall energy bills due to lower energy prices.

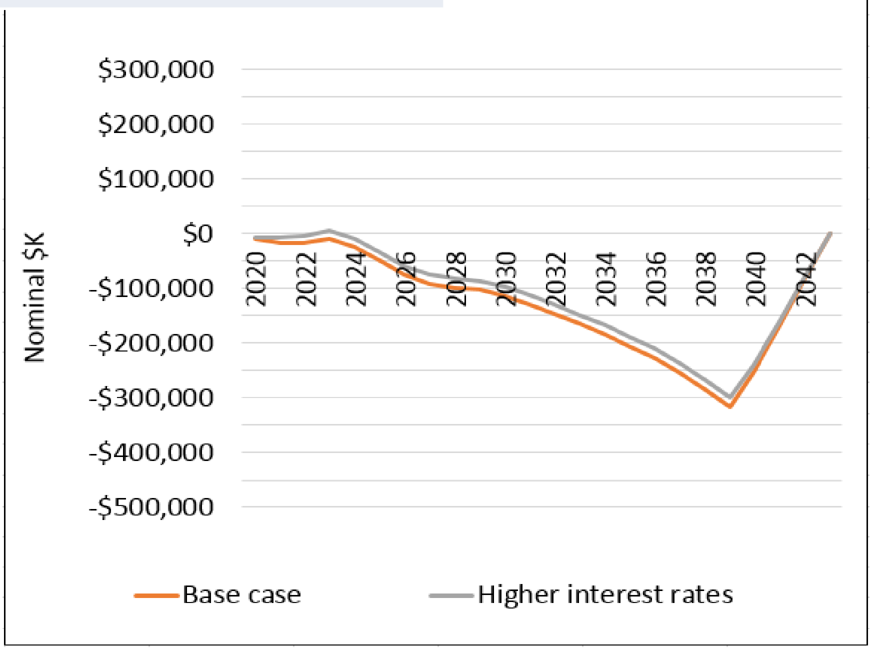
Tier 1 to 2023 – Interest Rates

Tier 1 only	Bill impact in 2023
Base case	**0.45%**
Higher interest rates	0.51%

Gross Program Cost

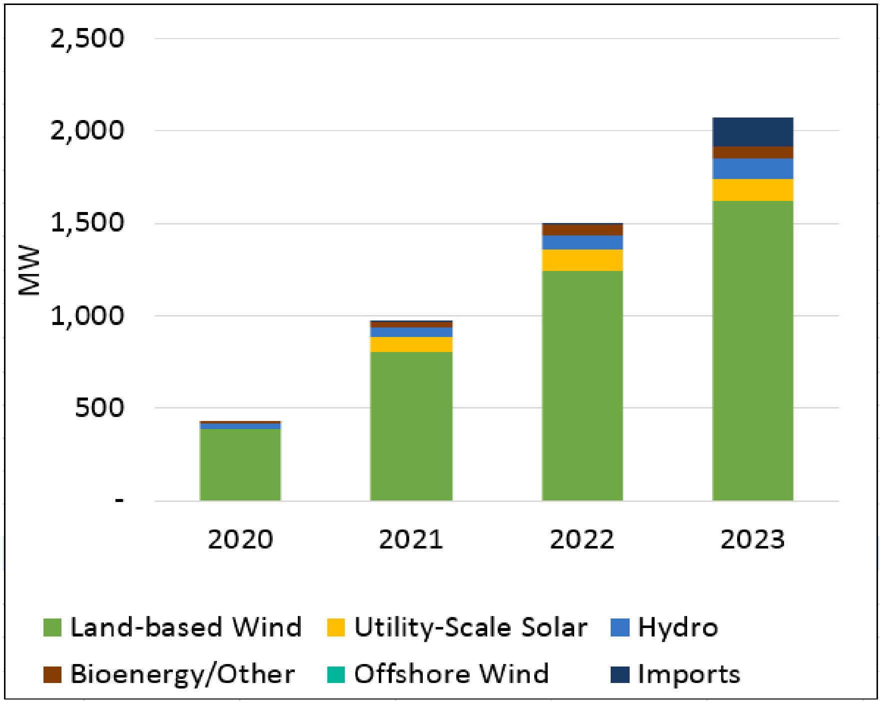


Net Program Cost

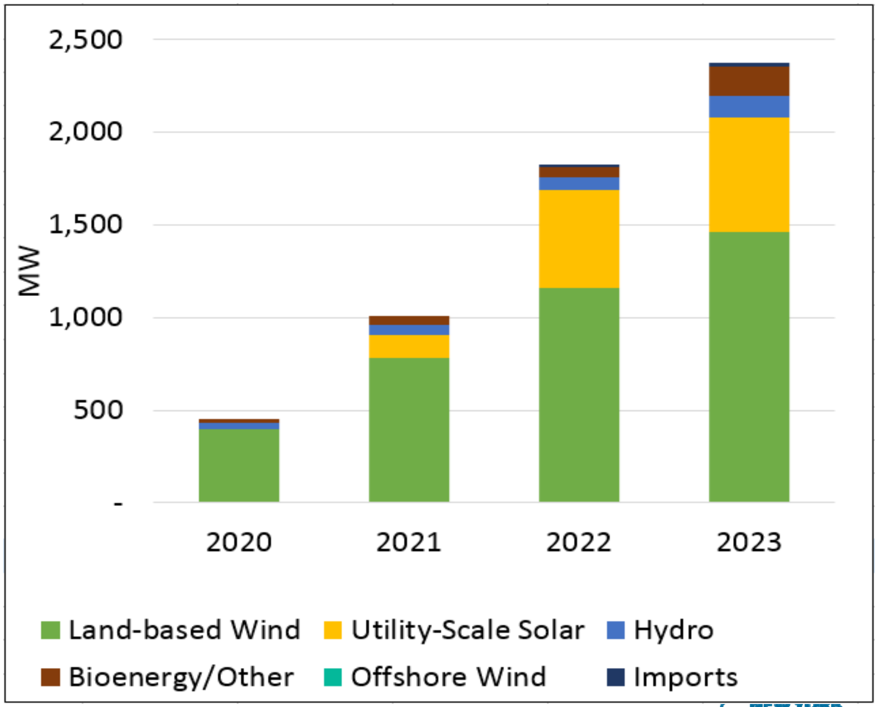


Tier 1 to 2023 – Wind Power Cost Sensitivity

Base



Higher LBW Cost



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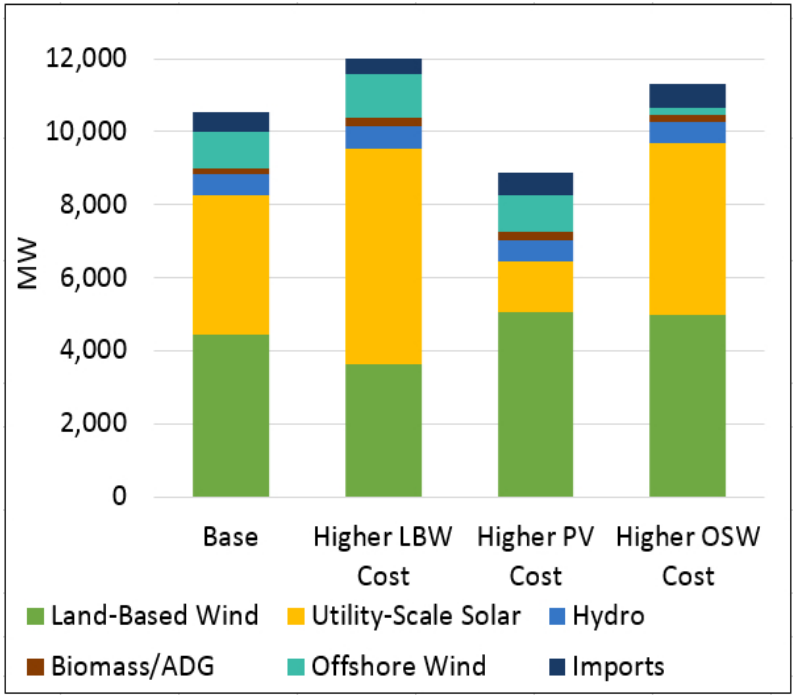
Tier 1 to 2030 – Technology Cost Sensitivities

Total CES Tier 1 deployment by 2030

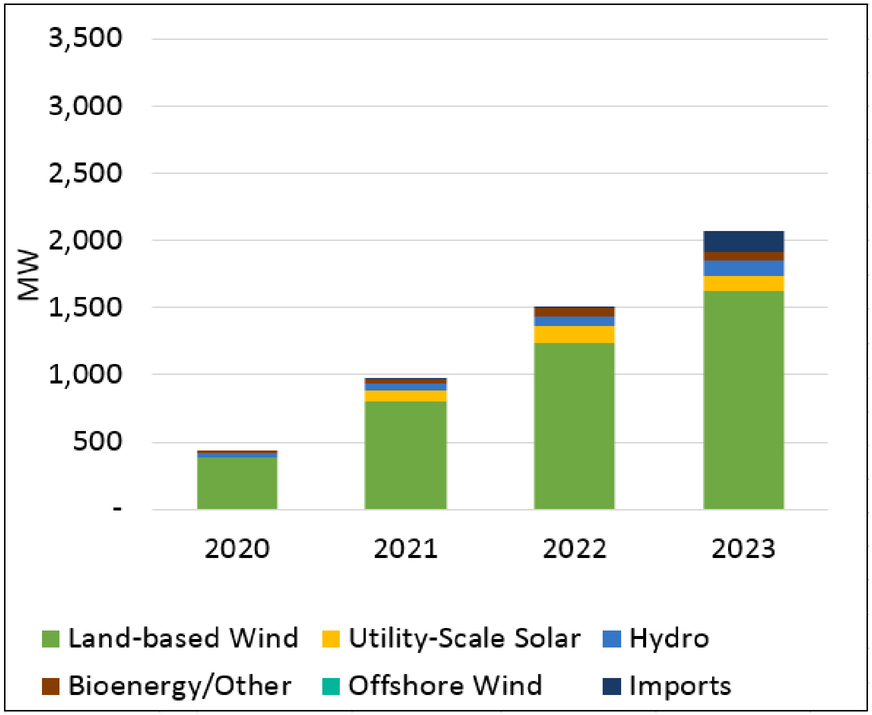


Tier 1 to 2030 – Technology Cost Sensitivities

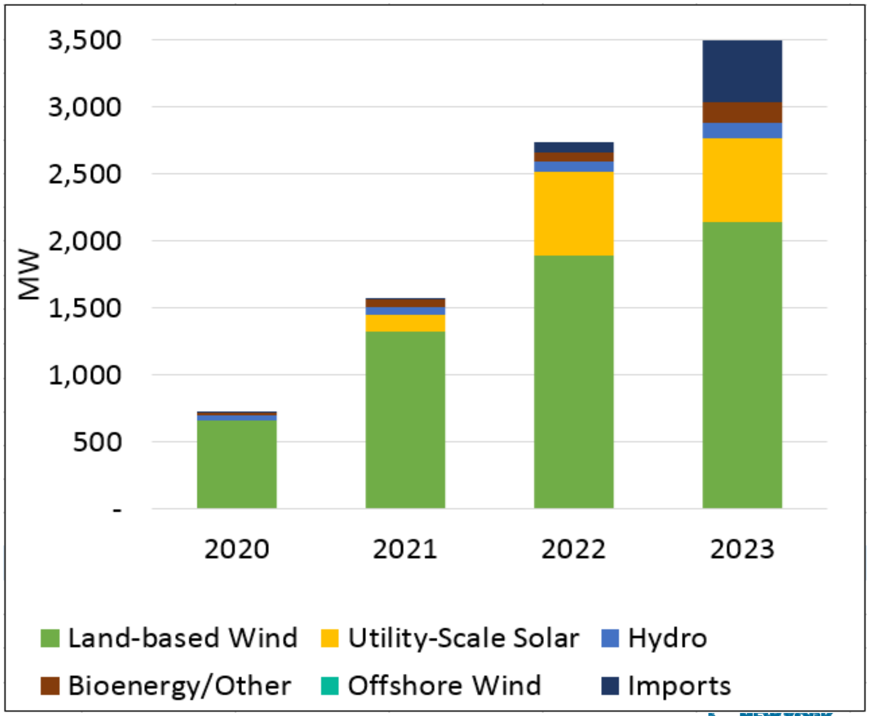
Case	Lifetime bill Impact – total CES
Base	0.94%
Higher LBW cost	1.16%
Higher PV cost	1.00%
Higher OSW cost	0.99%

Tier 1 Technology Mix to 2023 – System Load

Capacity - Base Case



Capacity - Higher Load



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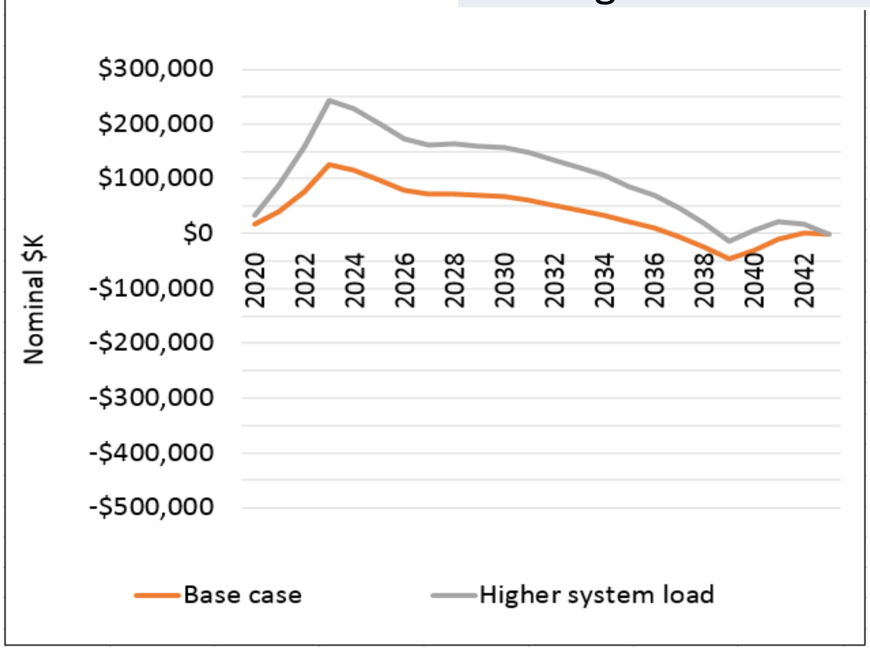
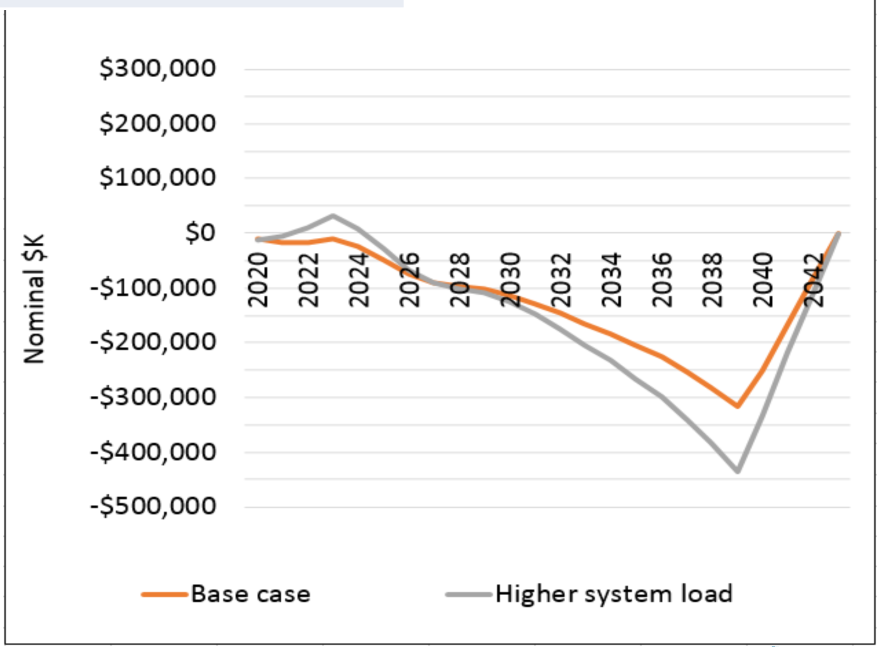
Tier 1 to 2023 – System Load

Tier 1 only	Bill impact in 2023
Base case	**0.45%**
Higher load	0.87%

Gross Program Cost



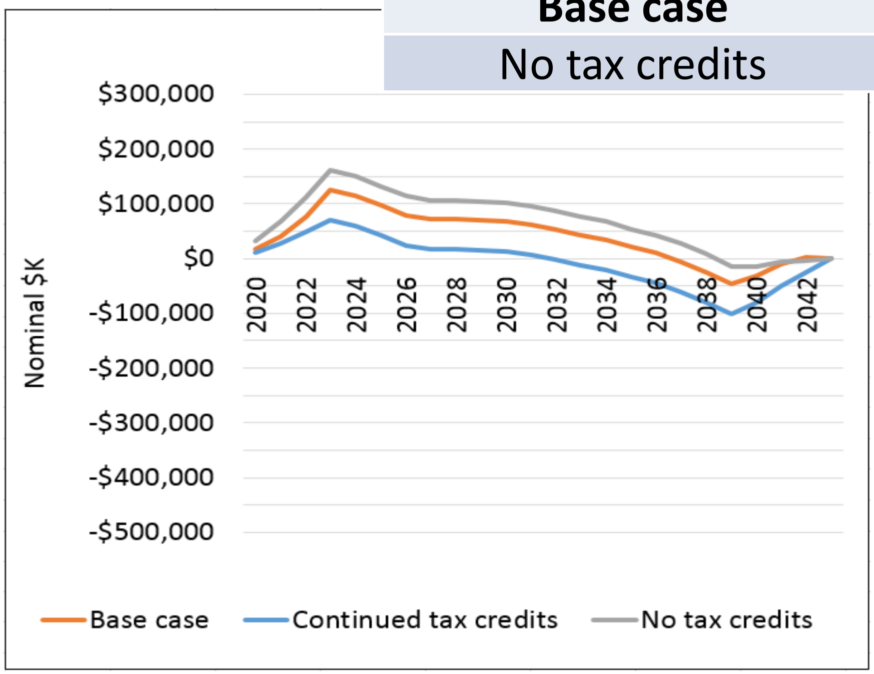
Net Program Cost



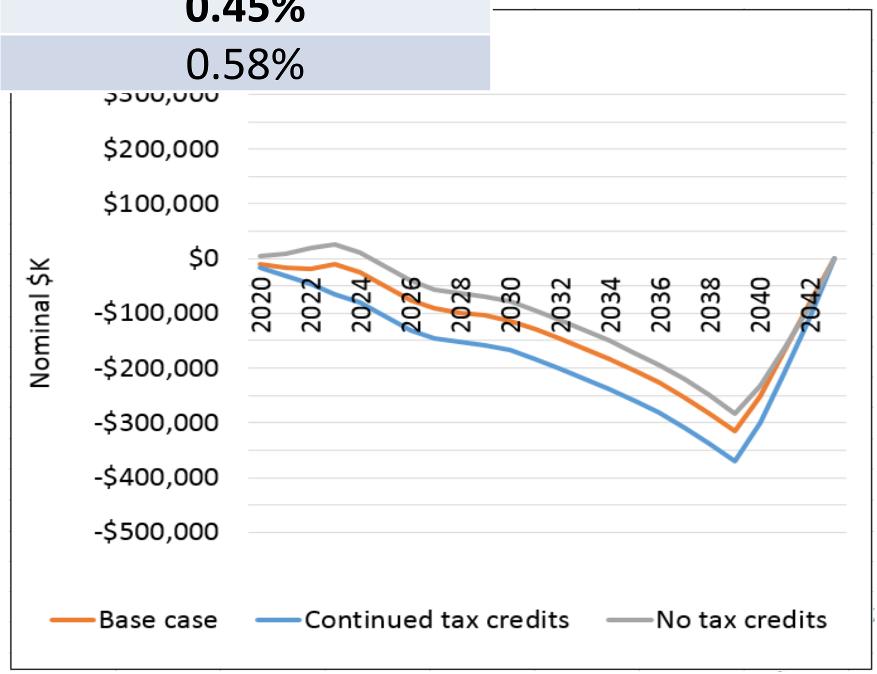
Tier 1 to 2023 – Federal Tax Credits

Tier 1 only	Bill impact in 2023
Continued tax credits	0.25%
Base case	**0.45%**
No tax credits	0.58%

Gross Program Cost



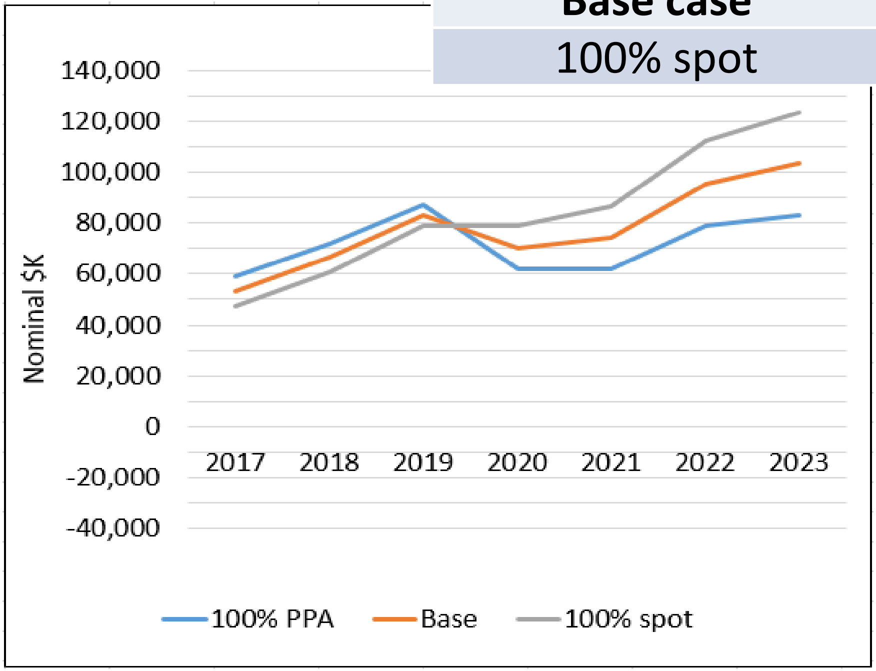
Net Program Cost



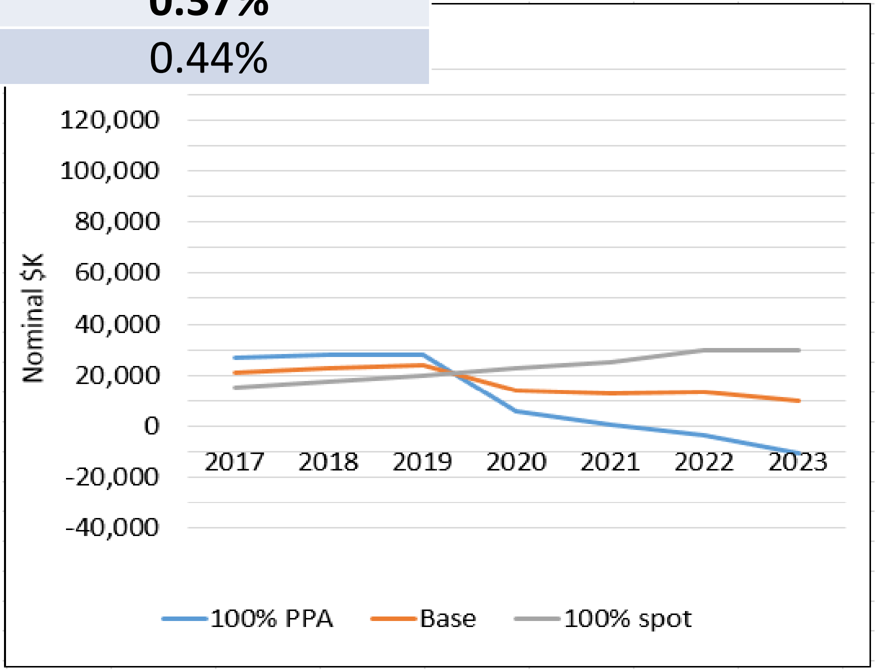
Tier 2A to 2023 – Procurement Structures

Tier 2A only	Bill impact in 2023
100% PPA	0.30%
Base case	**0.37%**
100% spot	0.44%

Gross Program Cost



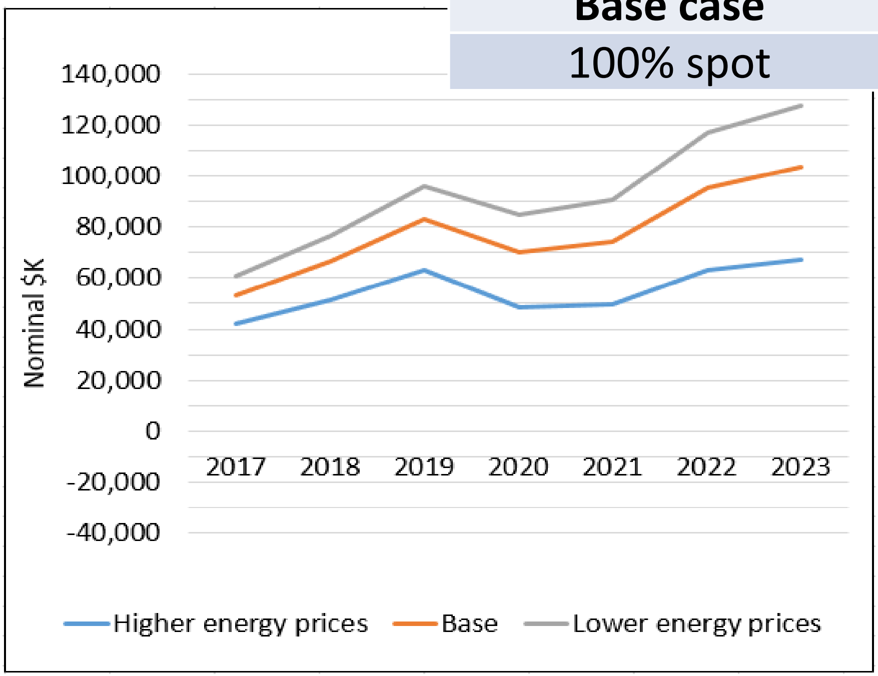
Net Program Cost



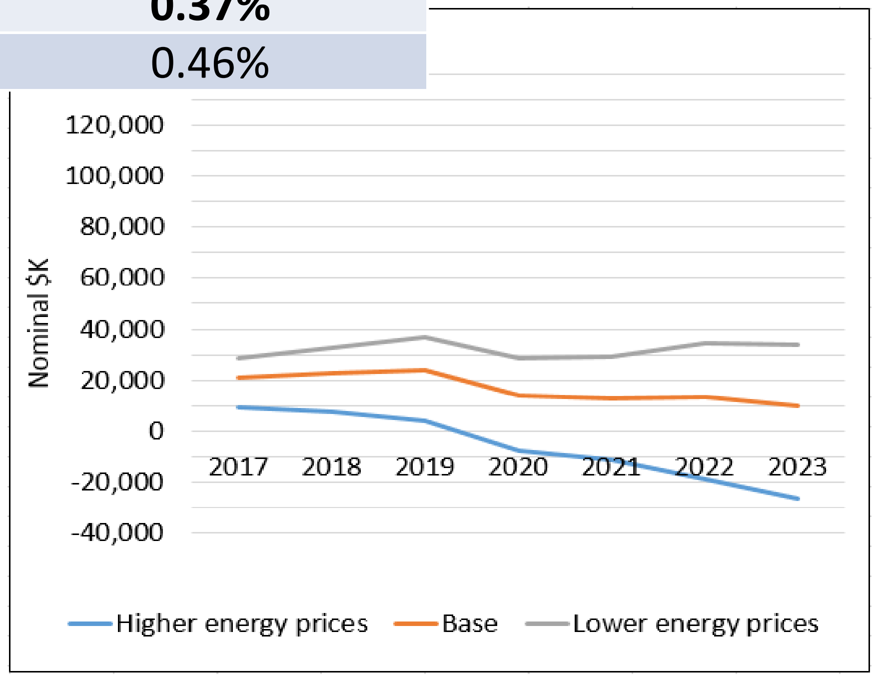
Tier 2A to 2023 – Energy Prices

Tier 2A only	Bill impact in 2023
100% PPA	0.24%
Base case	**0.37%**
100% spot	0.46%

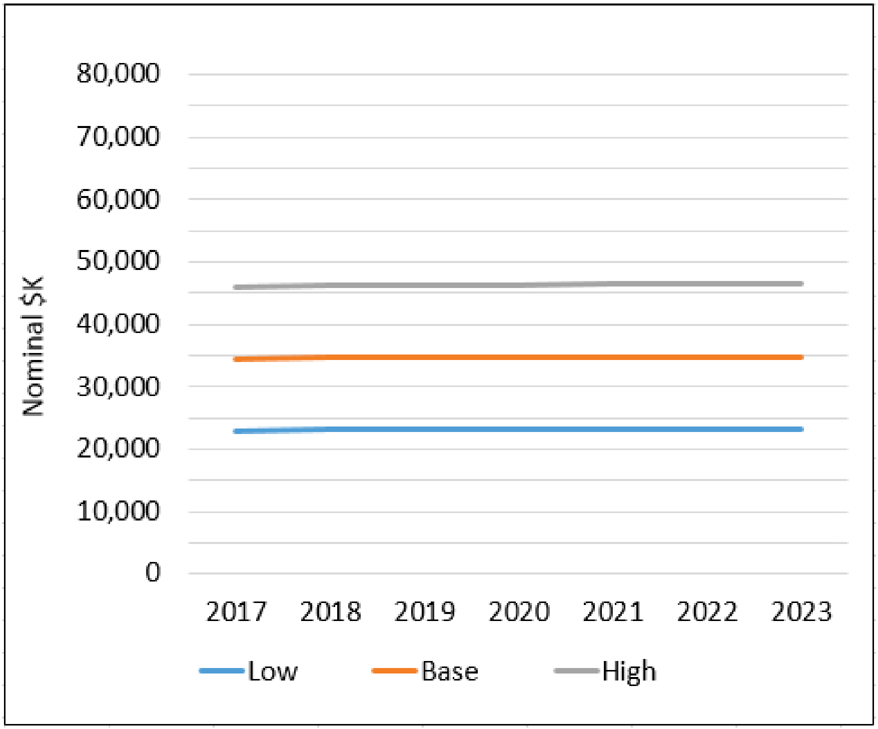
Gross Program Cost



Net Program Cost



Tier 2B Gross Program Costs to 2023



	Bill impact in 2023
Low case (PPA)	0.08%
Base case	**0.13%**
High case (spot)	0.17%

A conservative approach is taken by not presenting Tier 2B carbon savings as a specific CES benefit.

Tier 3

- Goal is to maintain a largely carbon-free emission source
  - Benefits include carbon emission reduction, economic impacts, fuel diversity
  - "Bridge" to a future where renewables make up a substantially higher percentage of the generation mix
- Quantity of Zero Emission Credits (ZECs) targets will need to be decided
  - Clean Energy Standard Staff White Paper proposed a phase-in approach, starting on 4/1/17
  - Other possible approaches can be considered

Tier 3, cont'd

- ZEC Alternative Compliance Payment (ACP)
  - Setting a price cap due to market power concerns
  - To be administratively determined, based on expected revenues and expenses of qualifying facilities
- Costs will have to be filed by prospective ZEC sellers
  - Confidentiality of data
  - Clean Energy Standard Cost Study made certain cost assumptions, but were just illustrative based upon known Ginna plant costs
- Revenue forecasts will have to be made
  - Clean Energy Standard Cost Study assumed three possible levels of wholesale electric prices in order to estimate each Tiers' costs
  - Revenue forecast for ZEC ACP calculation will likely be made on a relatively short-term basis, based on publicly available data

Tier 3, cont'd

- Range of costs based on high vs low energy prices and high vs low nuclear generation cost assumptions
- No publication of disaggregated or annual cost projections at this stage, in order to avoid prejudicing the "open book" cost assessment process with nuclear generators.

Lifetime NPV	To 2023 – Gross Program Costs	To 2023 – Net Program Costs
Tier 3	**Cost** of \$59 M - \$658 M	**Benefit** of \$928 M - \$1.08 B

Clean Energy Standard Cost Study Methodology & Assumptions

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May 4, 2016

Methodology

Tier 1 Modeling Overview

Supply Curve Analysis: Overview

- Supply Curve characterizes costs, MW quantity of newly constructed LSRs available to meet *annual incremental demand* in NY under long-term contracts with either:
- **Fixed-price REC contract ($/MWh)**, or
- **Bundled PPA ($/MWh)**: fixed payment for RECs, energy and capacity
- Supply sources *sorted* from low to high ***premium*** btw. levelized cost of energy (LCOE) and levelized projected commodity market value
- Results derived as all fixed-price REC, all bundled PPA, or a mix derived by blending (averaging) the results.

Team:
Sustainable Energy Advantage, LLC (SEA), with input data & resource assumption contributions from:
- AWS Truepower (wind)
- Antares Group (biomass)
- Daymark Energy Advisors (imports)

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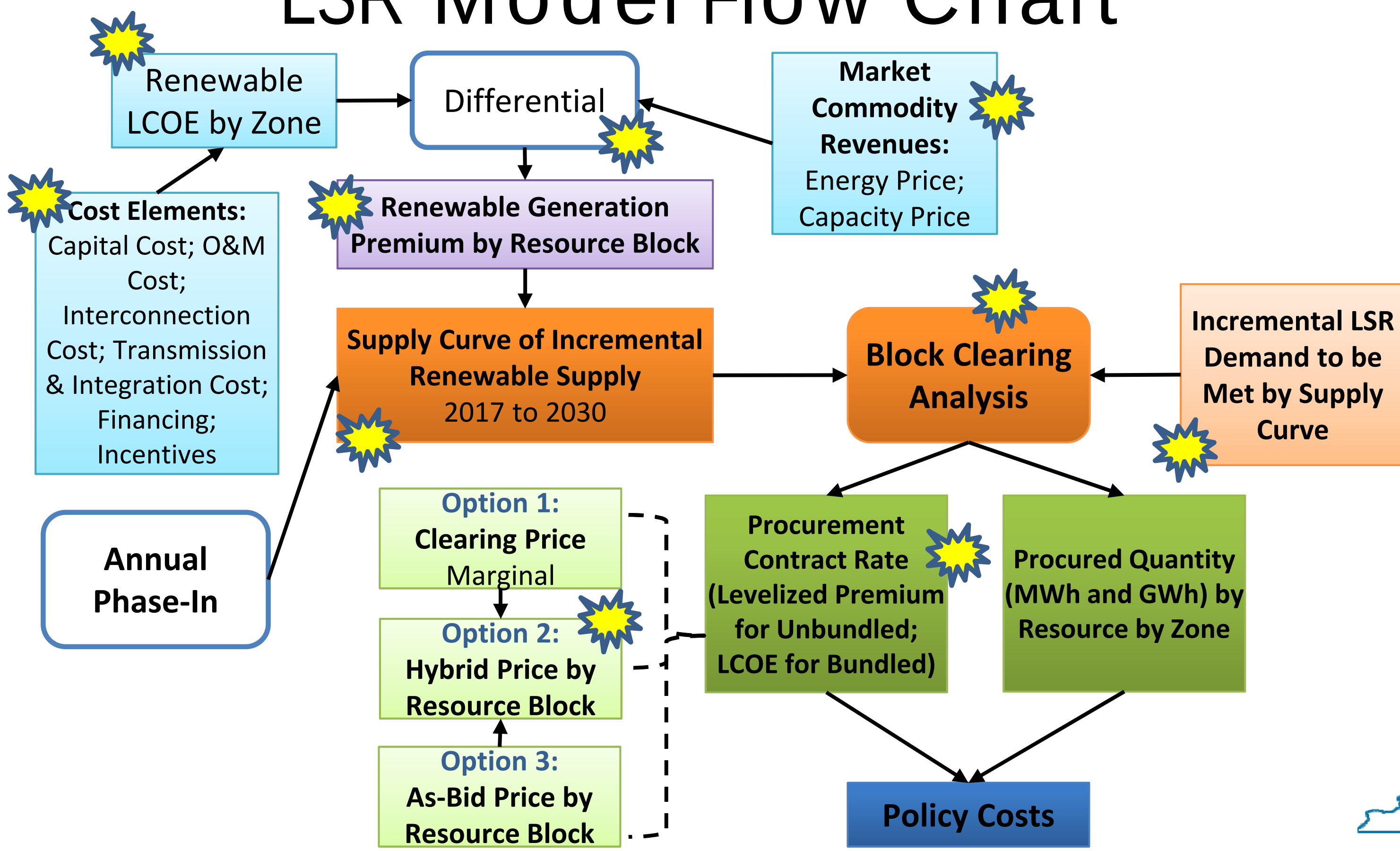
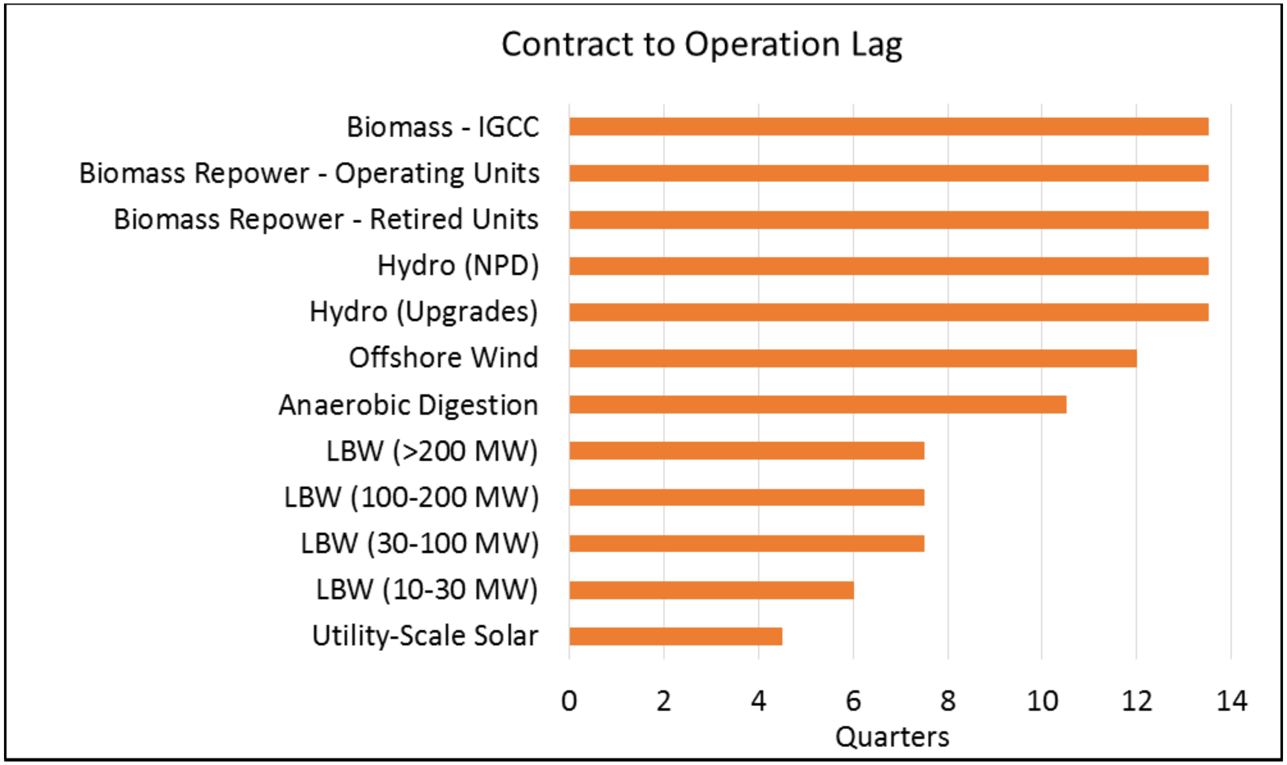
LSR Model Flow Chart



LSR Supply Curve: Key Analysis Parameters

- **Resource Types** characterized:
  - Meet RPS Main Tier eligibility criteria *and*
  - Most likely to contribute: wind (LBW, OSW); utility-scale solar; small hydro; biomass
- **Geography**:
  - Assumed Eligible: Within New York State + Imports from adjacent control areas with energy delivered to NY, capacity not committed elsewhere
  - Analysis includes: PJM (wind), Ontario (wind and small hydro) Quebec (wind) available to and deliverable to NYISO; New England ignored (net importer from NY)
- **Temporal Factors**
  - Each project assumed contracted for 20 yrs
  - Analysis horizon: start of commercial operation from 2017 – 2030
  - Policy payments for production in 2017 - 2049 when last of 20-year contracts expire

Assumed Lag from Contract to Operation



- *Rounded to nearest full year* in model

Key Characteristics of Resource Blocks

- Location (NYISO zone)
- Developable Quantity (in MW)
- Capacity Factor (%)
- "Typical" Scale (MW)
- Capital Expenditures (CAPEX) incl. T&I ($/kW)
- Cost of Network Upgrades
- Fixed & Variable O&M (or OPEX) Costs
- Production Profile
- Carrying charge (financing costs & structure) (% of CAPEX)
- Incentives
- Heat Rate & Fuel Cost (for biomass)

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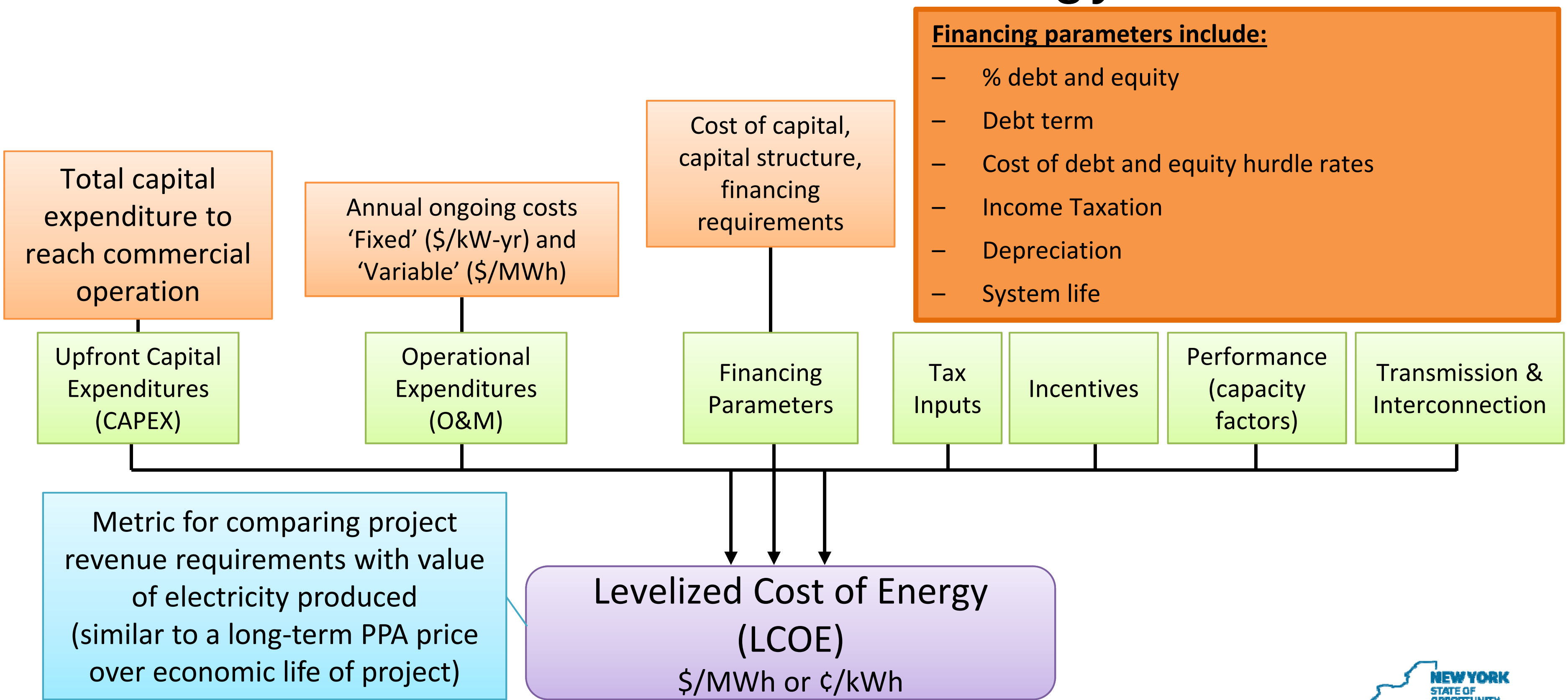
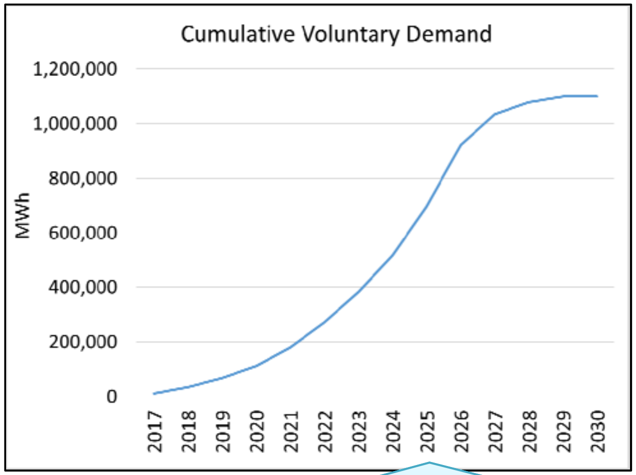
Levelized Cost of Energy



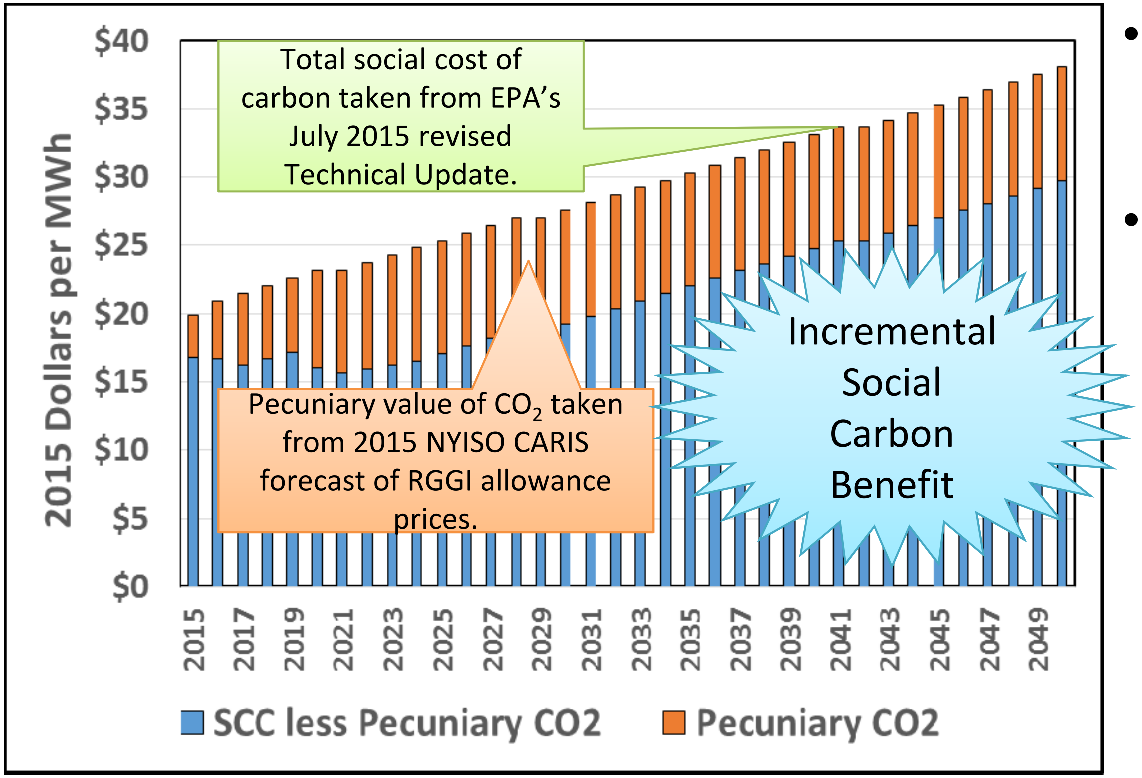
Competing Demands

- CES competes with other LSR demand in NY & adjacent regions for same LSR resources
  - **Voluntary market:** LSR supply curve deployed to meet aggregated demands from voluntary market and Tier 1 LSR policy each year; supply prorated to each➔ model only traces supply allocated to Tier 1 LSR
  - **Neighboring markets:** Not modeled explicitly ➔ assumed Tier 1 mechanism would encourage import into New York rather than export.



Assumed cumulative penetration of 1% of jurisdictional load by 2030, with “S” shape policy adoption schedule.

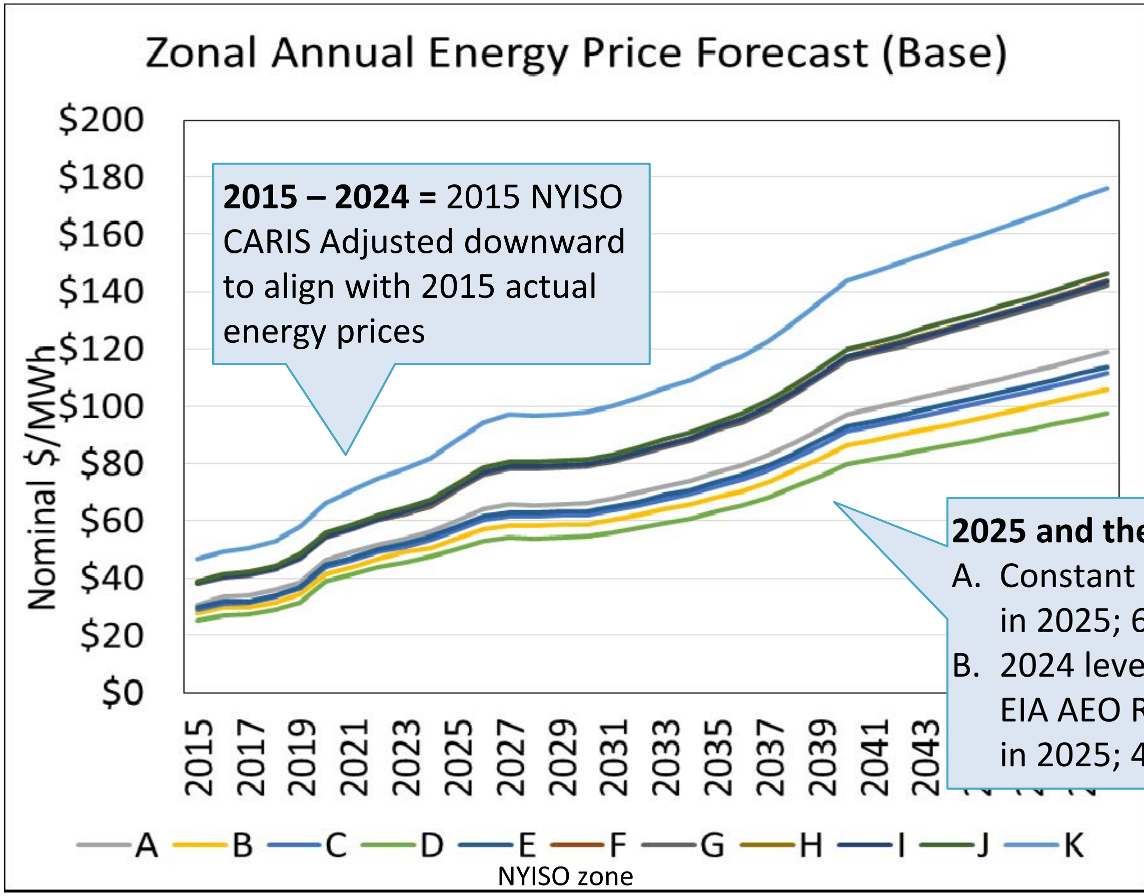
Net Program Costs Reflect Carbon Value ($/MWh)



- Avoided marginal CO_2 emission rate ~ 1,077 pounds (0.538 short tons) per MWh[1]
- Net program costs = gross program costs less *Incremental Social Carbon Benefit*

Energy and Capacity Market Value

Base Case Wholesale Energy Price Assumptions



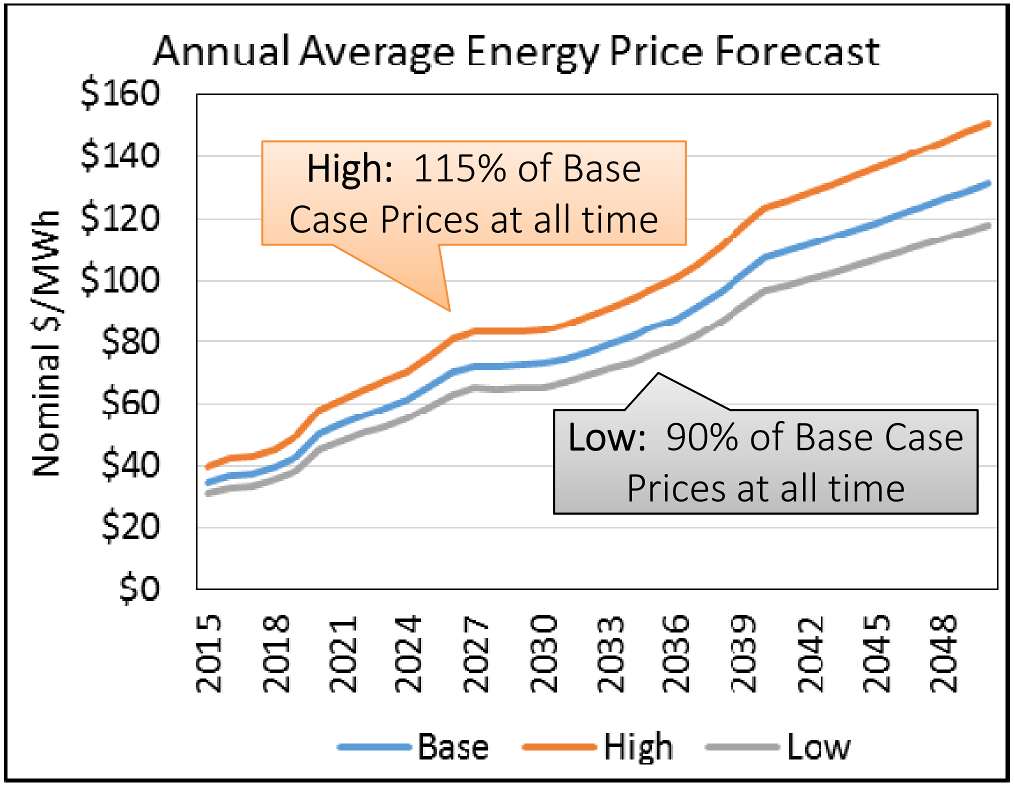
2015 – 2024 = 2015 NYISO CARIS Adjusted downward to align with 2015 actual energy prices

2025 and thereafter = Weighted average of two trajectories:

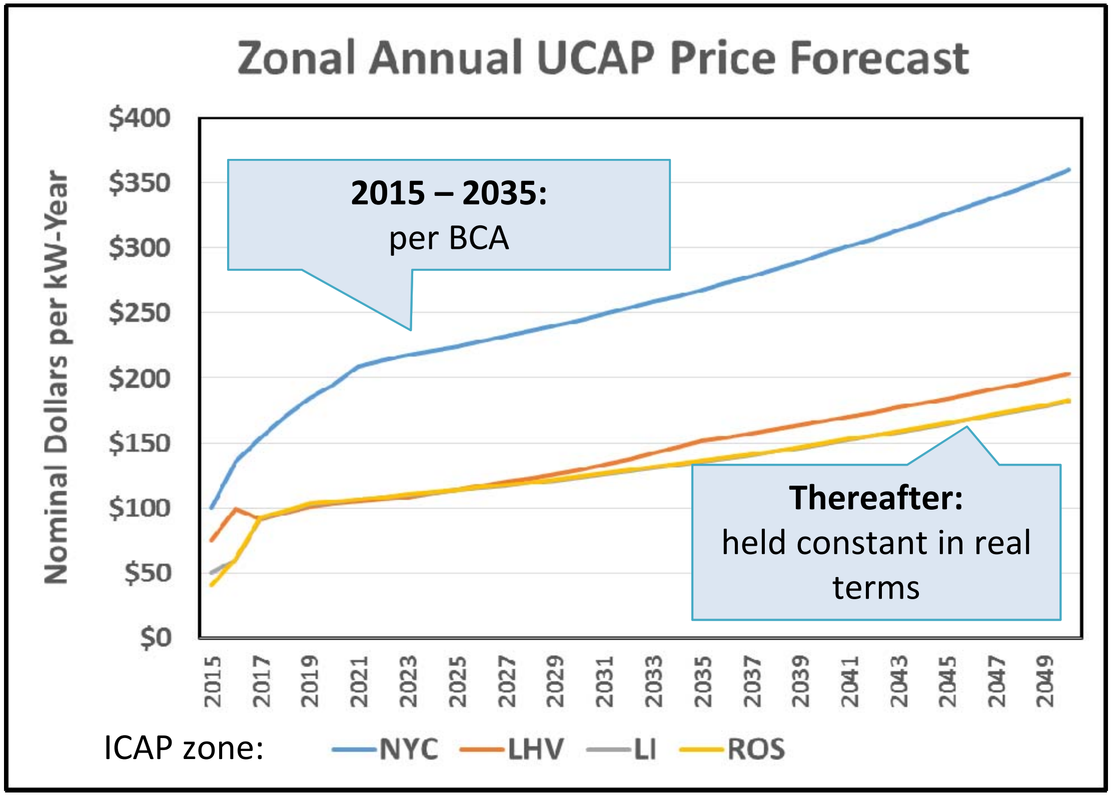
A. Constant in real dollar terms at 2024 level (Weight = 80% in 2025; 60% in 2026; 50% thereafter)
B. 2024 level trended at annual rate of change for the 2015 EIA AEO Reference Case NG price forecast (Weight = 20% in 2025; 40% in 2026; 50% thereafter)

- Avoided cost of carbon policy compliance embedded in the NYISO CARIS energy price forecast
- Implication: Carbon value extrapolated in proportion to the Base energy price forecast.

Alternative energy market price futures to test sensitivity of program costs to market values



Capacity Price Forecast



BCA's Zonal Summer and Winter ICAP generator prices translated to zonal average annual UCAP prices using average of zonal Summer 2015 and Winter 2015/16 translation factors

BCA = Order Establishing the Benefit Cost Analysis Framework, Case 14-M-0101, January 21, 2016

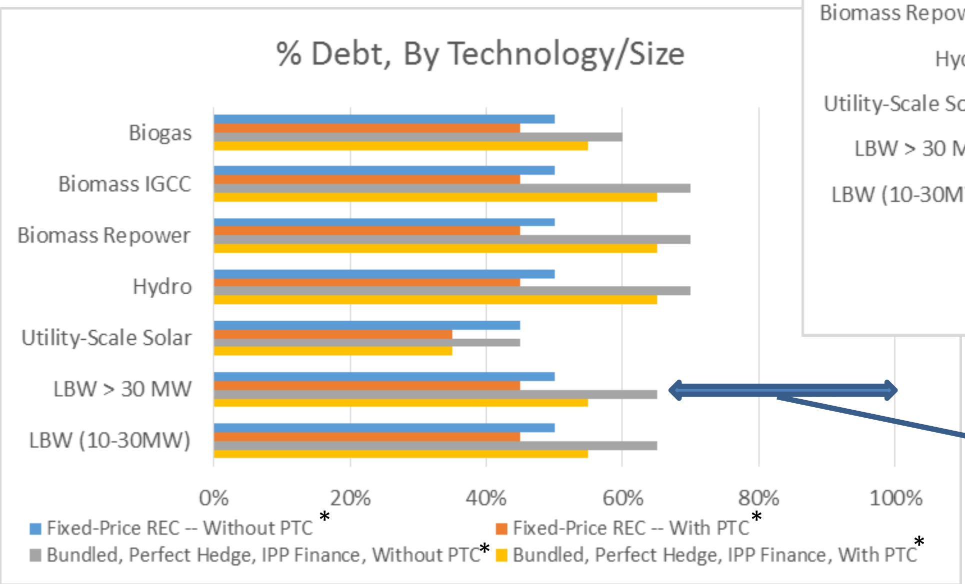
Financing

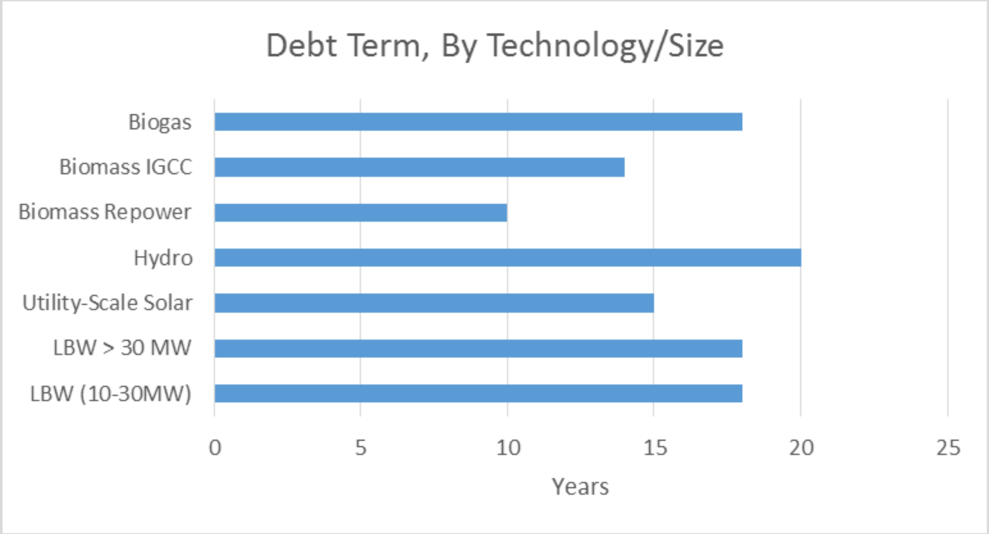
Financing Assumption Framework

- The differing risk exposure under different contracting and incentive regimes is reflected solely through differences in the cost of capital
- (revenue streams are not discounted from the forecasts to reflect risk)
- Financing assumptions calibrated against available benchmark data from outside NYS and data from past Main Tier solicitations in NY.

Financing Assumptions: Debt % and Term

<u>Additional Assumptions</u>:
20-yr contract duration
35% Federal, 7.1% NYS tax rate

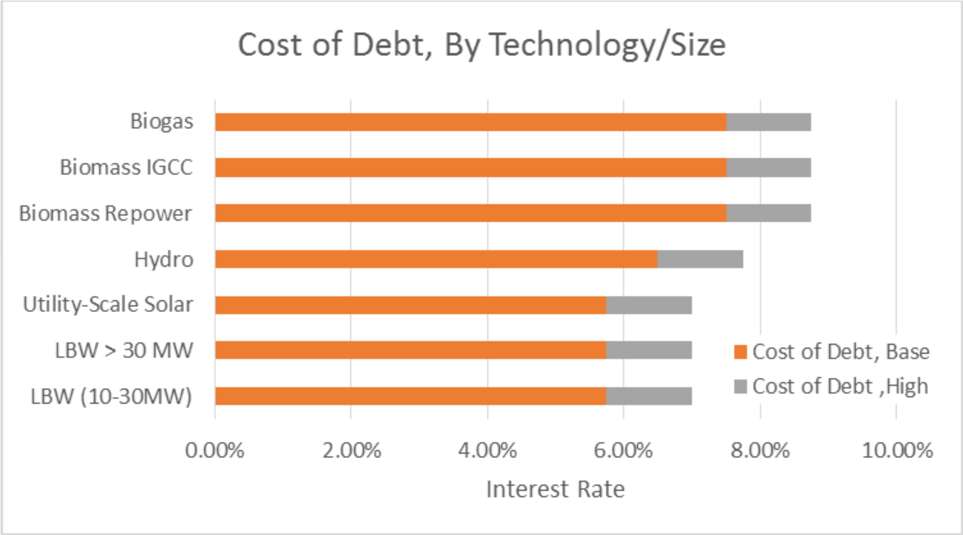


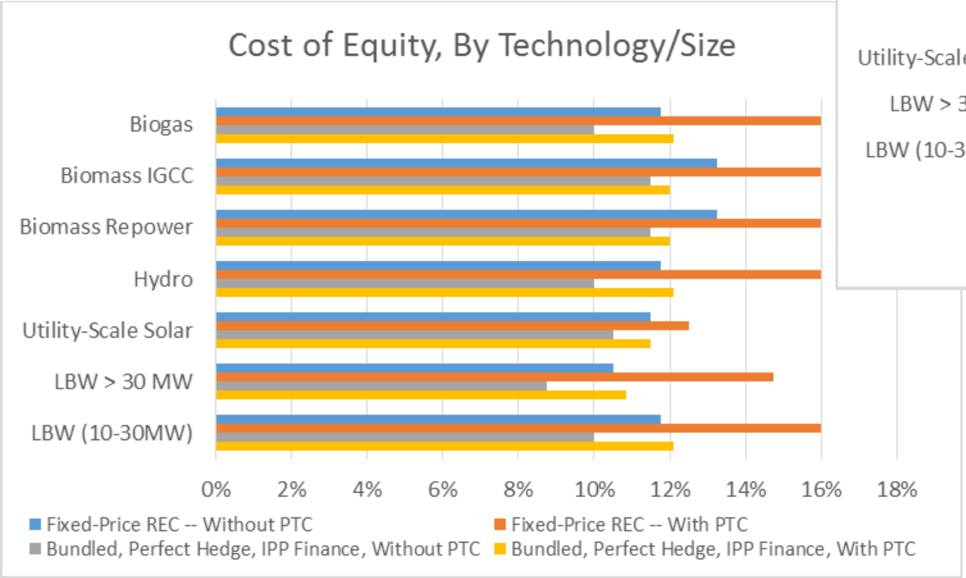


Remainder sourced from equity.

* = PTC or ITC as applicable

Financing Assumptions: Cost of Equity & Debt





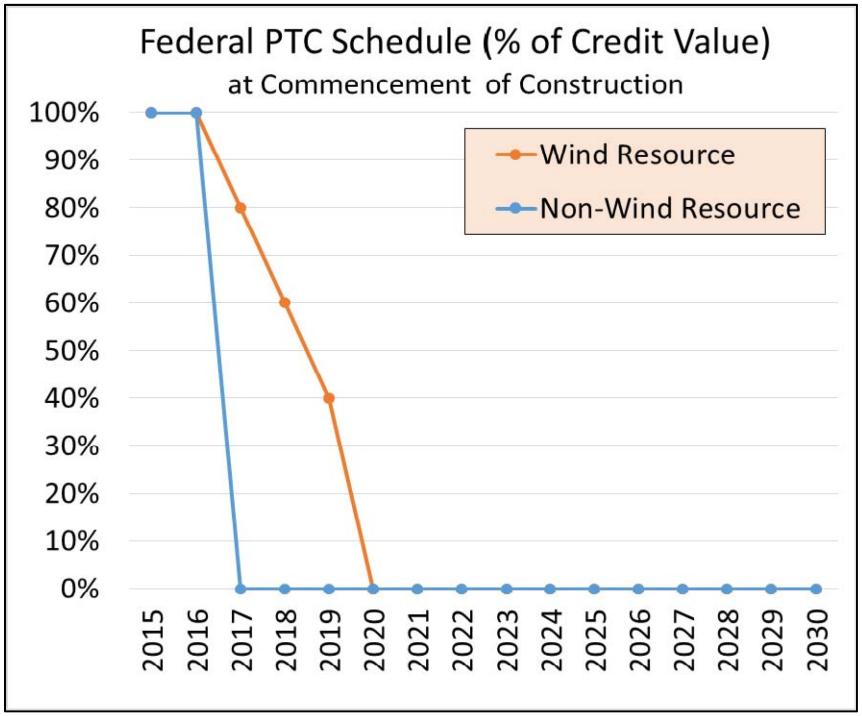
Technology-Specific Financing Cost Assumptions: OSW

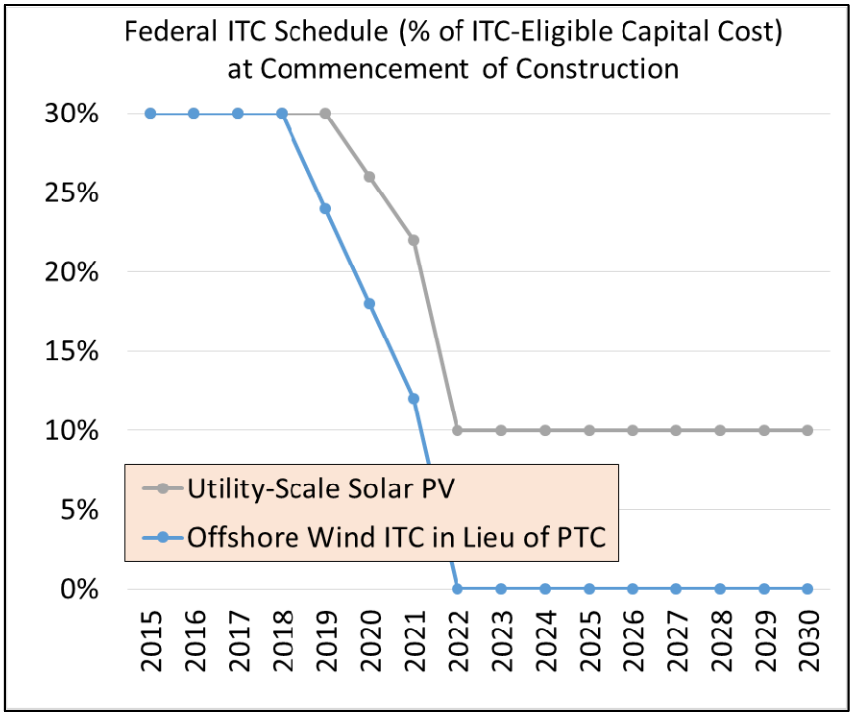
- Financing risks (hence, equity IRR) expected to decrease over time as market matures
- Established 3 ***maturity phases*** (starting point, mid-point, end point) with declining IRR as market matures
  - Under Bundled PPA, IRR reduces from 11.0% to 9.0%
  - Under Fixed REC, IRR reduces from 12.75% to 10.75%
  - ‘end point’ = fully mature (equivalent to LBW, except for modest construction period & performance risk differential)

Procurement/Contracting Options	% Debt
Fixed-Price REC – With 10% ITC	50%
Fixed-Price REC -- With 30% ITC	45%
Bundled, Perfect Hedge, IPP Finance, With 10% ITC	70%
Bundled, Perfect Hedge, IPP Finance, With 30% ITC	60%

Federal Incentives

Base Case PTC and ITC Schedules





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Increased scarcity of tax equity ➔ assumed investors unable to fully monetize value of tax credits

Technology	Equivalent % of Tax Credit Value Effectively Monetized
LBW (10-30 MW)	80.0%
LBW (30-100 MW)	90.0%
LBW (100-200 MW) (>200 MW)	90.0%
Utility-Scale Solar PV	90.0%
Hydro (Upgrades)	75.0%
Hydro (NPD)	75.0%
Woody Biomass	75.0%
Biogas	75.0%
Offshore Wind	90.0%

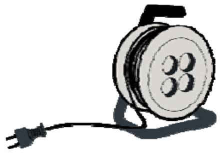
Value of FTC reduced to the percentage of 'face value.'

Transmission and Interconnection

Transmission & Interconnection (T&I) Costs

"Extension Cord" (generator lead costs): Interconnect to existing transmission system included in CAPEX modeled as sum of:

- New generator lead line: miles * voltage-specific $/mi
- "non-line" cost of interconnecting to via new or existing substation, e.g. cost of building new substation, expanding existing substation, installing new breaker & other equipment



NEW YORK
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OPPORTUNITY.

Transmission & Interconnection (T&I) Costs

- **Network Upgrade Costs** (NWU): upstream non-reimbursed costs charged by NYISO or interconnecting utility through the interconnection process
- Estimated broadly & generically to capture magnitude of expected costs
- Additional work (outside of scope) in State Resource Planning Study (SRP) will add more info and precision

Tier 2 Modeling Overview

Tier 2A Approach

- By definition, have material revenue opportunities in surrounding markets
  - Historically: New England spot Class I REC prices, *if energy delivered to ISO-NE*
  - In the future, PJM 'Tier 1' RPS markets could become competitively attractive.
- Objective: retain energy (GHG impact) & RECs (CES targets) in NY thru 2030
- Targets:
  - Large hydro not eligible
  - Initial: contribution of eligible resources to 2014 baseline (i.e., generation of such resources net of exports at that time)
  - Increase as Main Tier RPS contracts end
- *What revenues would successfully attract such resources to sell their RECs in New York State rather than exporting their energy to other markets?*
  - Cost estimates based on assessment of generator's opportunity cost

NEW YORK STATE OF OPPORTUNITY.

Tier 2A: Spot vs. Bundled PPA

Spot

- Analysis based on NY market providing a similar or slightly lower level of revenue risk as spot prices available in alternative markets
- Assumed: Alternative Compliance Payment is set as a cap on spot REC prices; Tier 2A cost estimate based on cap

PPA

- Analysis based on NY bundled PPA revenue stream providing necessary incentive for generation to stay in New York State at a lower expected cost due to the added revenue certainty/lower risk
- Assumed duration from year generation first becomes eligible through 2030 (i.e., progressively decreasing contract duration)

Risks & rewards differ → expected revenue streams valued differently

Tier 2B Resources Have Limited REC Revenue Opportunities

- Generally older renewable electricity generators with limited alternative revenue opportunities (not 'Class I' eligible)
  - Generally lower than cost of accessing them
- Objectives: retain energy (GHG impact) & RECs (CES targets) in NY thru 2030, acquire rights to count them, and keep projects from shutting down
- Targets: set based on amount of LSR in the 2014 baseline not owned by NY State Entities, net of expired RPS Main tier contracts.
- *What revenues would successfully cause resources to sell their RECs in NY?*
  – Costs estimated based on representative pricing levels observed for comparable resources in Northeast RPS programs.
  – Assumed sufficiently above transactions costs to motivate sale of RECs to CES obligated entities (but not much more)

60

Tier 1
Technology Specific Methodology & Assumptions

Land-Based Wind

Offshore Wind

Utility-Scale Solar PV

Imports

Small Hydroelectric

Woody Biomass

Biogas

Land-Based Wind

Overview of Approach

- Detailed geospatial approach identifies candidate windy sites
- Reflects site-specific nature of LBW resource potential, production, project cost, and interconnection cost
- Raw potential derated to reflect varying likelihood of permitting success
- Cost functions used to represent development cost variations associated with site characteristics.

LBW Capital Expenditures (excluding T&I Costs)

- Starting CAPEX (2015 NREL ATB) = $1,692/kW (in 2013 $); for 200-MW project in idealized central US plains ➔ 3 multiplicative adjustments applied to starting point to reflect cost characteristics specific to each LBW site:

Locational adjustments:

NY Region	NYISO Zones	EIA Regional Factor	Siting Factor	Final Adjustment Factor
Upstate	Rest of state	1.01	1.06	1.07
NYC	Zone J	N/A	N/A	N/A
LI	Zone K	1.25	1.10	1.38

Reflects difference btw. national average and costs specific to Upstate NY and Long Island

Reflects siting & soft cost difference from idealized (central plains) site

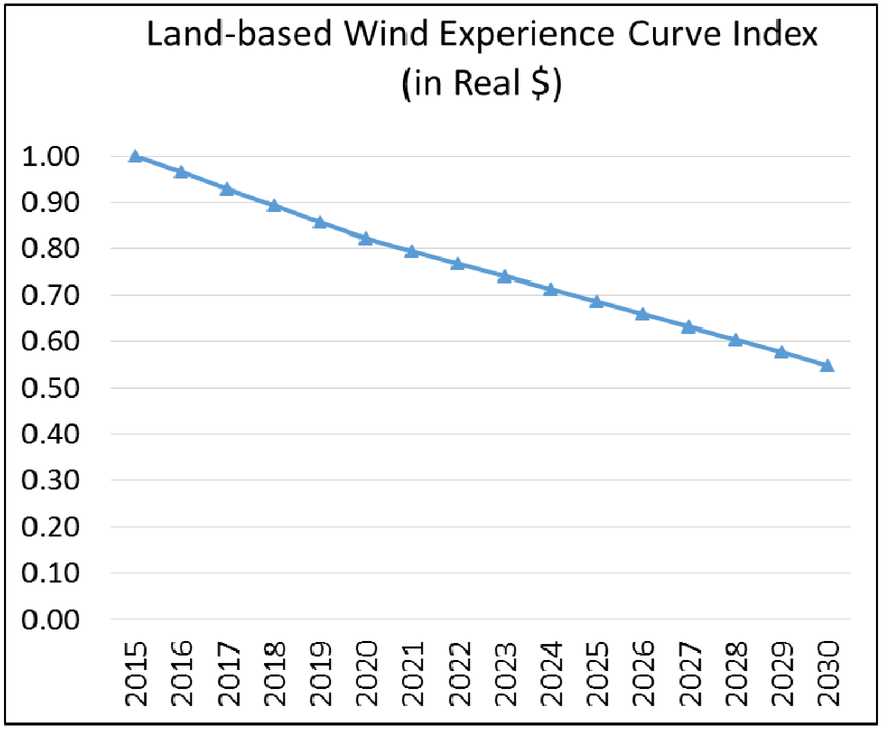
Size adjustment: reflects diseconomy of scale in size categories smaller than 200 MW baseline

Technology Size Category	Adjustment Factor
LBW 10-30 MW	1.30
LBW 30-100 MW	1.15
LBW 10-30 MW	1.02
LBW >200 MW	1

Topography adjustment: reflects cost differences in site topography (slopes) and access to roads.

Land Type		Definition	Min. Elevation (m)	Min. Elevation Difference vs. Surroundings (m)	Adjustment Factor
Plain	1	Slope = 0 – 5%, Not 3 or 4	N/A	N/A	1.00
Rolling Hills (Accessible)	2	Slope = >5 – 15%, Not 1,3 or 4	N/A	N/A	1.07
Rolling Hills (Remote)	3	Slope = 8 – 12%, Not 4	300	100	1.12
Mountainous	4	Slope = >10 – 20%	500	N/A	1.22

LBW CAPEX Experience Curve Index



- Derived by indexing Mid NREL ATB CAPEX forecasts for NREL's 'techno-resource group' (TRG) 2.
  - TRGs 2 and 3 most consistent with conditions with majority of sites in New York.
- Projected rates of cost decline slower than the rate of inflation ➔ LBW CAPEX increases over time in nominal dollars

Geospatial LBW Resource Potential Analysis

LBW Primary and Secondary Constraints

Primary Constraints - Excluded Areas	Buffer
Adirondack and Catskill Parks	100 ft.
National Historic Preserves / Sites / Parks	100 ft.
Wildlife Management Areas	100 ft.
State Unique Area	100 ft.
State and Local Parks	100 ft.
National Monuments	100 ft.
National Wildlife Refuges	100 ft.
National Park Service Land	100 ft.
Fish and Wildlife Service Lands	100 ft.
American Indian Lands	100 ft.
GAP Status 1 & 2 Lands (Protected Lands)	100 ft.
Urban Areas	Class (22) – 200 m; Class (23) & (24) – 500 m
Wetlands & Waterbodies	100 ft.
Large Airports	20,000 ft.
Small / Medium Airports	10,000 ft.
Proposed Wind Farms	3 km
Existing Wind Farms	3 km
Slopes > 20%	N/A
Appalachian Trail	3 km

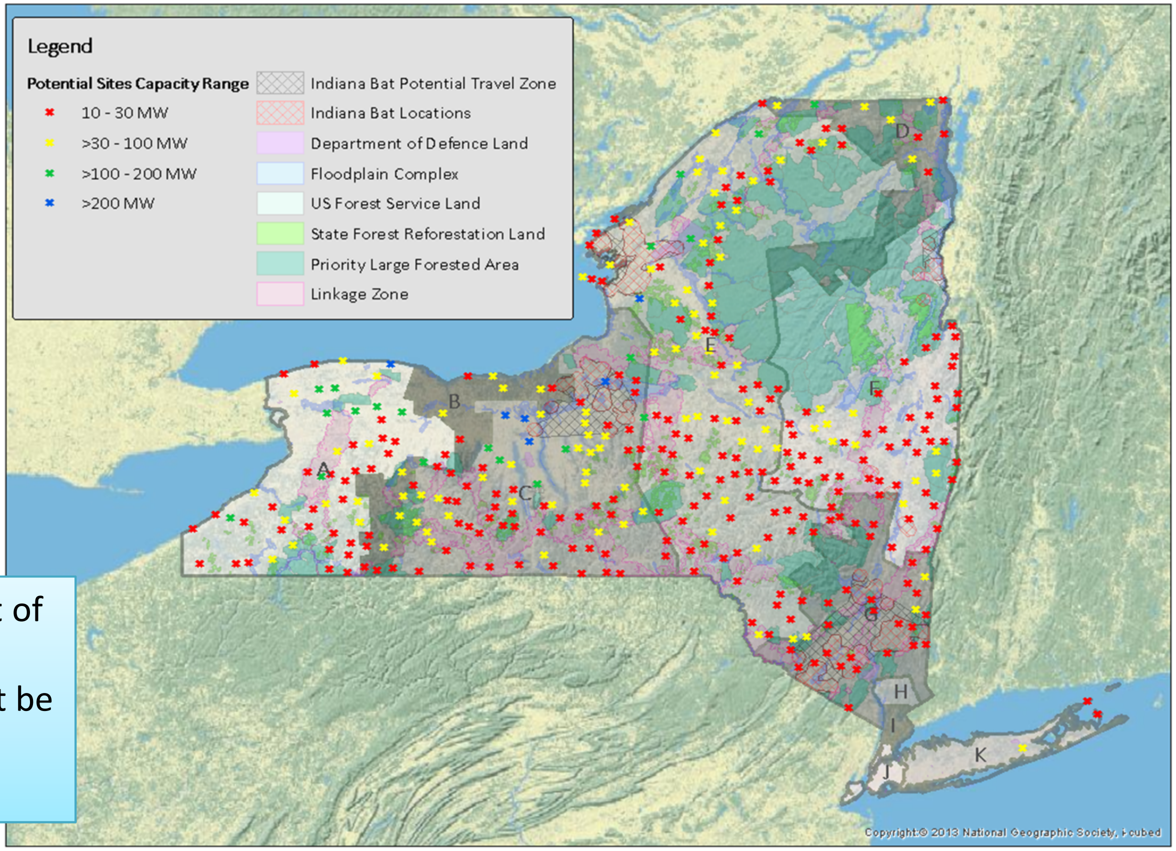
- Primary constraint areas excluded from analysis
- Model *can* apply probability de-rates to sites intersecting secondary constraint areas to represent a higher hurdle to permitting success *(not applied in analysis)*:
  - Department of Defense Lands
  - Forest Service lands
  - State forest lands
  - Modeled rare species distributions
  - Modeled migratory bird stopovers
  - Bat distributions/locations/travel zones
  - Terrestrial connectivity and resilience

LBW Sites

- Continuous areas capable of hosting a wind project >10 MW
  - Land area and power density (measured in MW/km^2) consistent with topography
  - Wind speeds at 4 hub heights (80m, 100m, 120m and 140m)
  - Average slope and elevation
  - Distance to nearest existing transmission lines and substations at 5 voltages
- Manual site characterization to assess potential siting conflicts due to presence or proximity of dwellings/roads at individual sites:
  - Sites with “substantial” housing density excluded outright
  - % de-rates applied to reduce the available land areas associated with 4 levels of housing densities:
    - High: 95% (i.e., only 5% of the land area developable)
    - Medium: 75%
    - Low: 30%
    - None: 5%

Distribution of Potential LBW Sites

(370 New York LBW Sites in the Supply Curve)



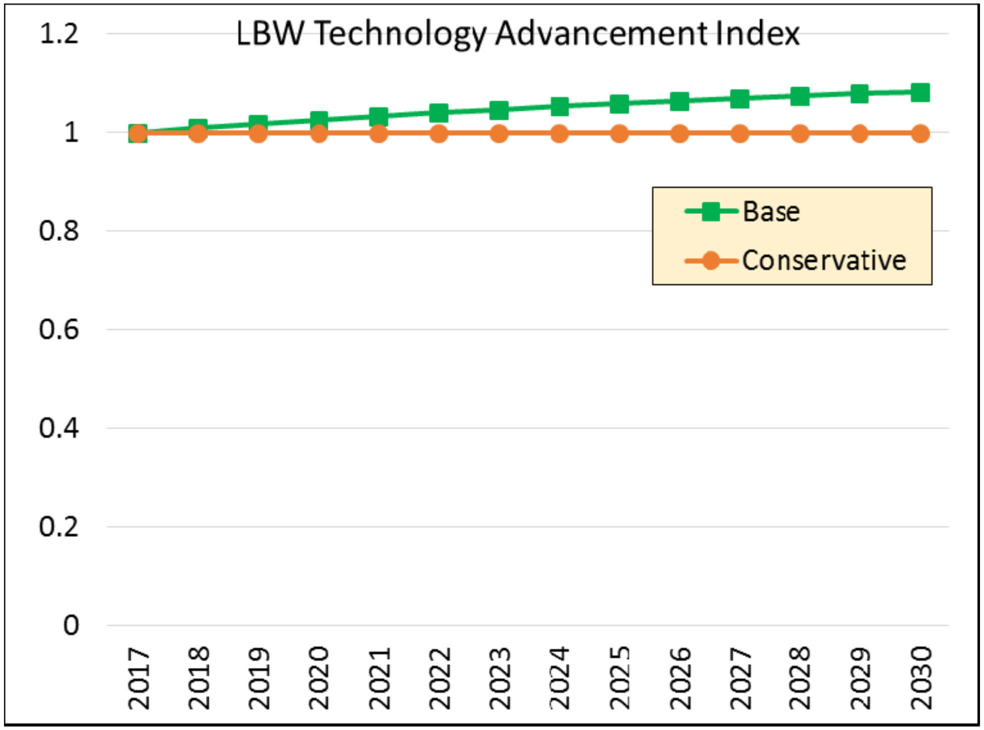
NOTE: This is the result of probabilistic geospatial analysis and should not be interpreted as defining actual project sites.

LBW Capacity Factors

- Capacity factors modeled at four hub heights (80m, 100m, 120m and 140m) using scalable wind turbine power curve representing current, commercially-available technology
- Hub heights (HH) used as a proxy for a combination of blade length (rotor swept area) and HH for determining capacity factors at any given wind regime ➔ assumed to continue recent increasing trend over span of study.
- Evolution of capacity factors over time was modeled based on two parameters:
  - Average fleet hub height evolution; and
  - Technology advancement at a constant hub height.

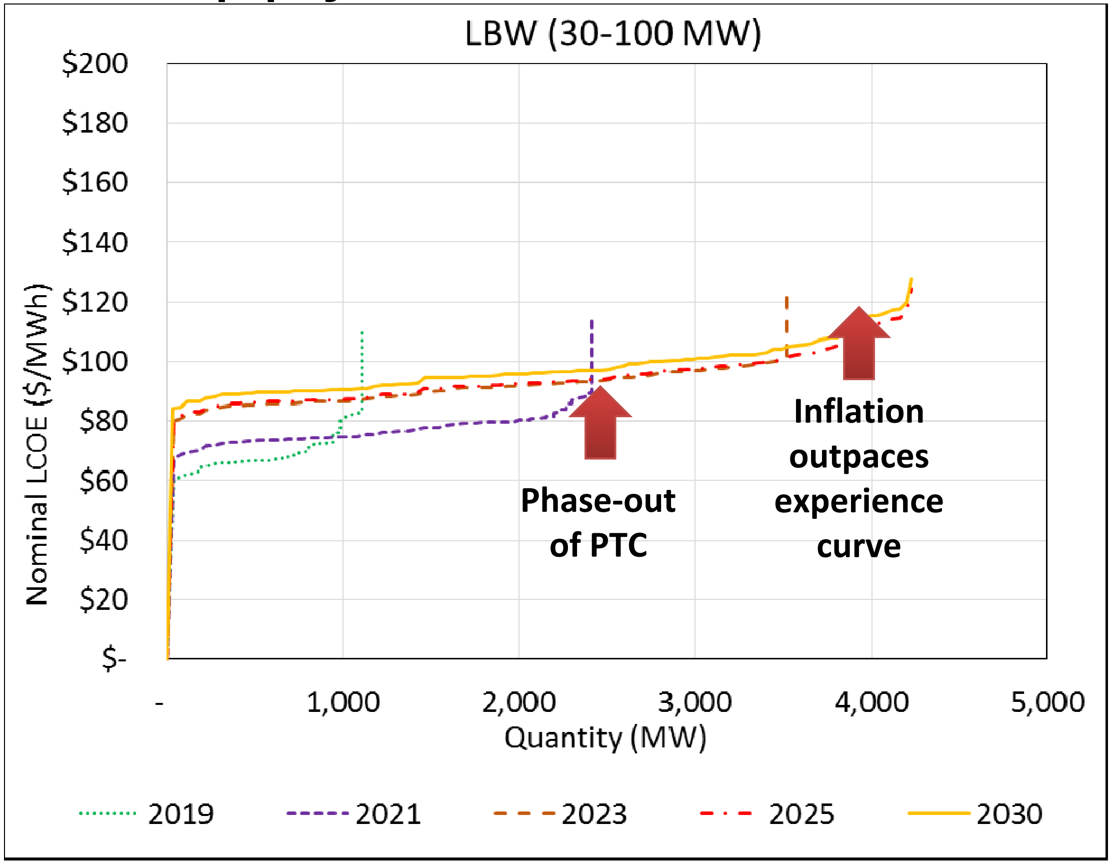
LBW Technology Advancement Factors

(Additional technology improvement, represented by c.f. at a given HH)



- Derived from 2015 NREL ATB mid and low trends for TRG 3
- Reduced NREL ATB rate of change figures by 50% to eliminate potential double counting of impact driven by HH increase

LCOE Supply Curves: LBW 30-100 MW



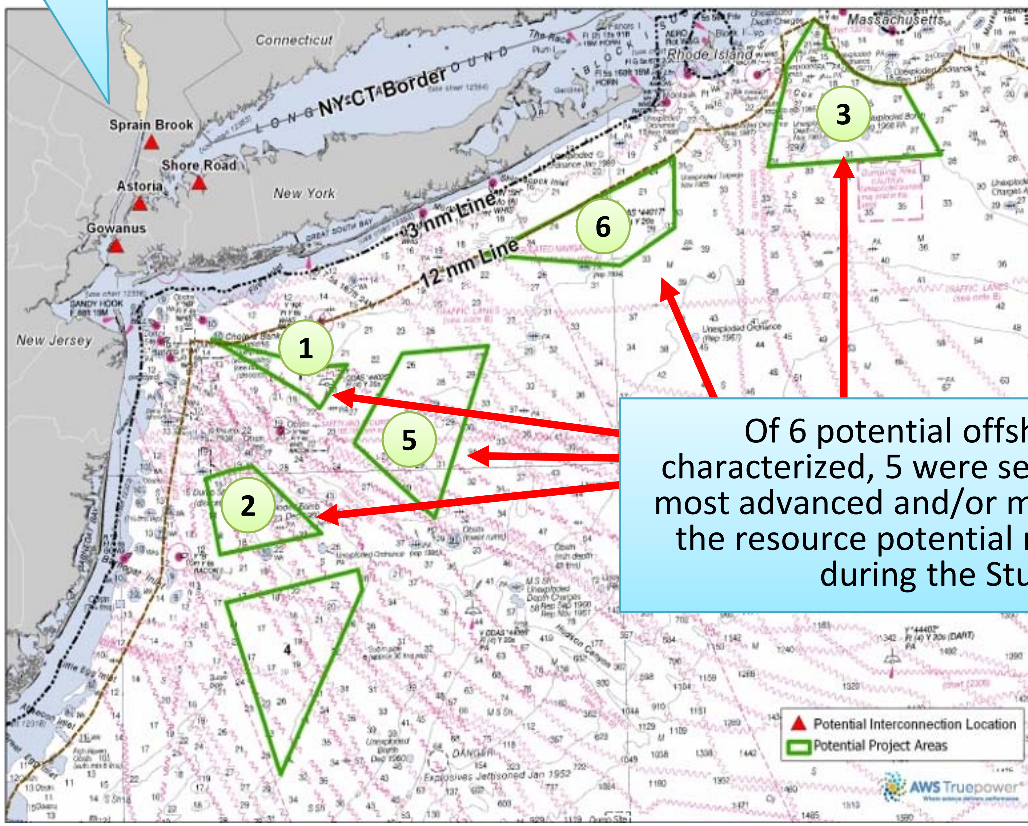
Offshore Wind

OSW Data and Methodology

- OSW analysis builds on:
  - March 2016 *Massachusetts Offshore Wind Future Cost Study*
  - 2015 NREL ATB
  - Earlier NYSERDA-internal analysis
- Starting point from NYSERDA-internal cost & resource analysis → adjusted/extrapolated using SIOW 2016 Massachusetts Study, NREL ATB to reflect confluence of several factors:
  - Latest European experience in cost reduction;
  - Scale economies and industrialization of OSW sector (global learning)
  - Continued scaling from 5 MW to 8 MW class turbines
  - U.S. learning and industry scaling
  - Availability of long-term revenue certainty
  - Increased competition consistent w/ eastern US commitment to deploy OSW at scale thru 2030
  - Development of domestic supply chain, spreading of fixed costs

OSW Resource Potential

Interconnection Points



Offshore Site	Area (km²)	Build-Out Potential (MW)	MW Assumed Available before 2030 (MW)
1	285	855	791
2	663	1,989	1295
3	1,521	4,563	2594
5	1,372	4,116	2402
[illegible]	[illegible]	3,081	1869

Of 6 potential offshore wind areas characterized, 5 were selected as the closest, most advanced and/or most representative of the resource potential reasonably available during the Study period.

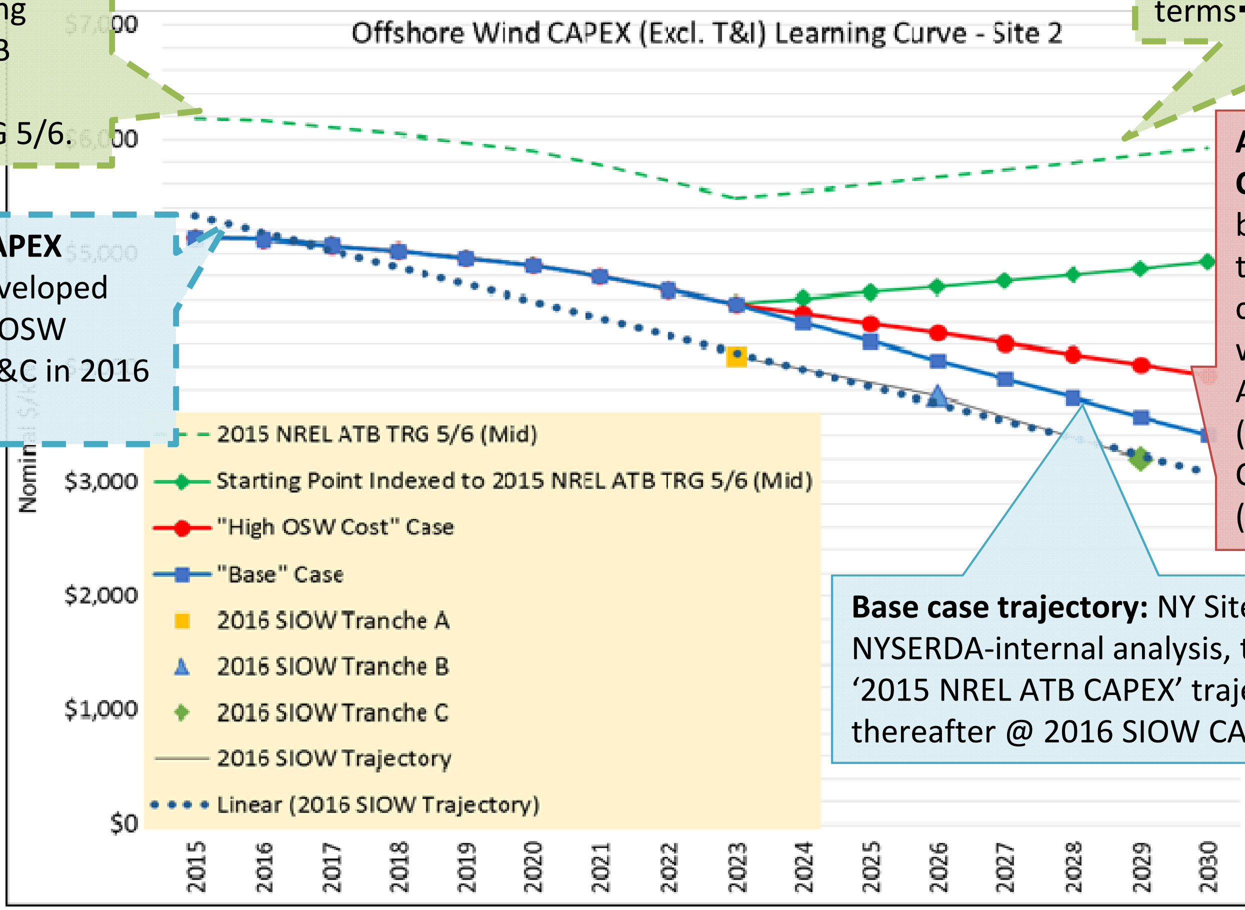
Figure A.8

OSW CAPEX Trajectory

'2015 NREL ATB CAPEX trajectory': developed using 2015 NREL ATB CAPEX (Mid) trajectory, TRG 5/6.

From 2023 onward, this forecast trajectory increases in nominal terms➔ too conservative.

'2016 SIOW CAPEX trajectory': developed from trending OSW tranches A, B, &C in 2016 SIOW analysis.



Alternative high cost OSW CAPEX trajectory: 2023 base case starting point, trended to hybrid learning curve index based on a weighting of '2015 NREL ATB CAPEX trajectory' index (30% weight) & '2016 SIOW CAPEX trajectory' index (70% weight).

Base case trajectory: NY Site-specific CAPEX from NYSERDA-internal analysis, trended until 2023 at '2015 NREL ATB CAPEX' trajectory, trended thereafter @ 2016 SIOW CAPEX trajectory

OSW T&I Costs

- T&I costs for ERIS from NYSERDA-internal analysis used, but OSW projects assumed able to access capacity revenue.
- In deriving T&I estimates, the following key assumptions were made:
  - Most of distance between OSW project & onshore interconnection point via undersea cable
  - Fraction of T&I costs associated with onshore facilities assumed owned by interconnecting utility and charged back to project owner (at lower cost of capital), while remainder assumed to be financed by project owner at same capital structure as generation facilities.
- T&I costs held constant in real $ through 2020; thereafter, assumed annual decrease by 1% in real $ through 2030

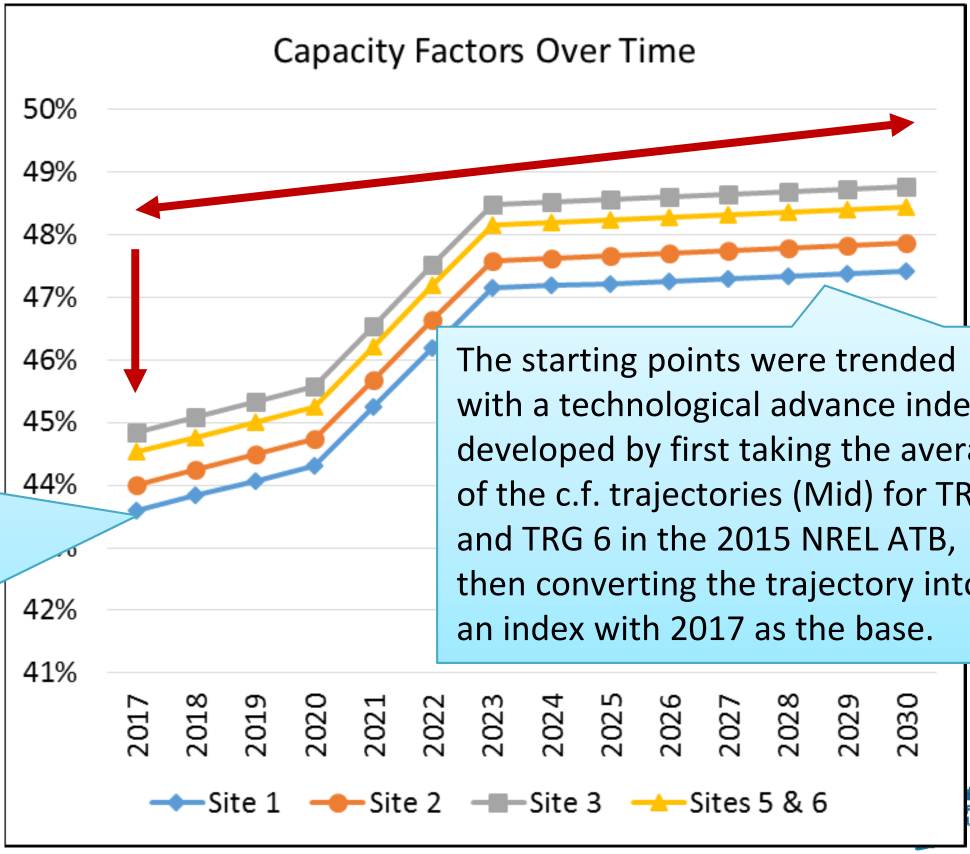
Technological Advancement

CAPEX and OPEX figures reflect technology evolution which includes both larger turbines at higher hub heights, and other technology advances.

Net c.f.s were applied to a composite power curve for an 8-MW wind turbine.

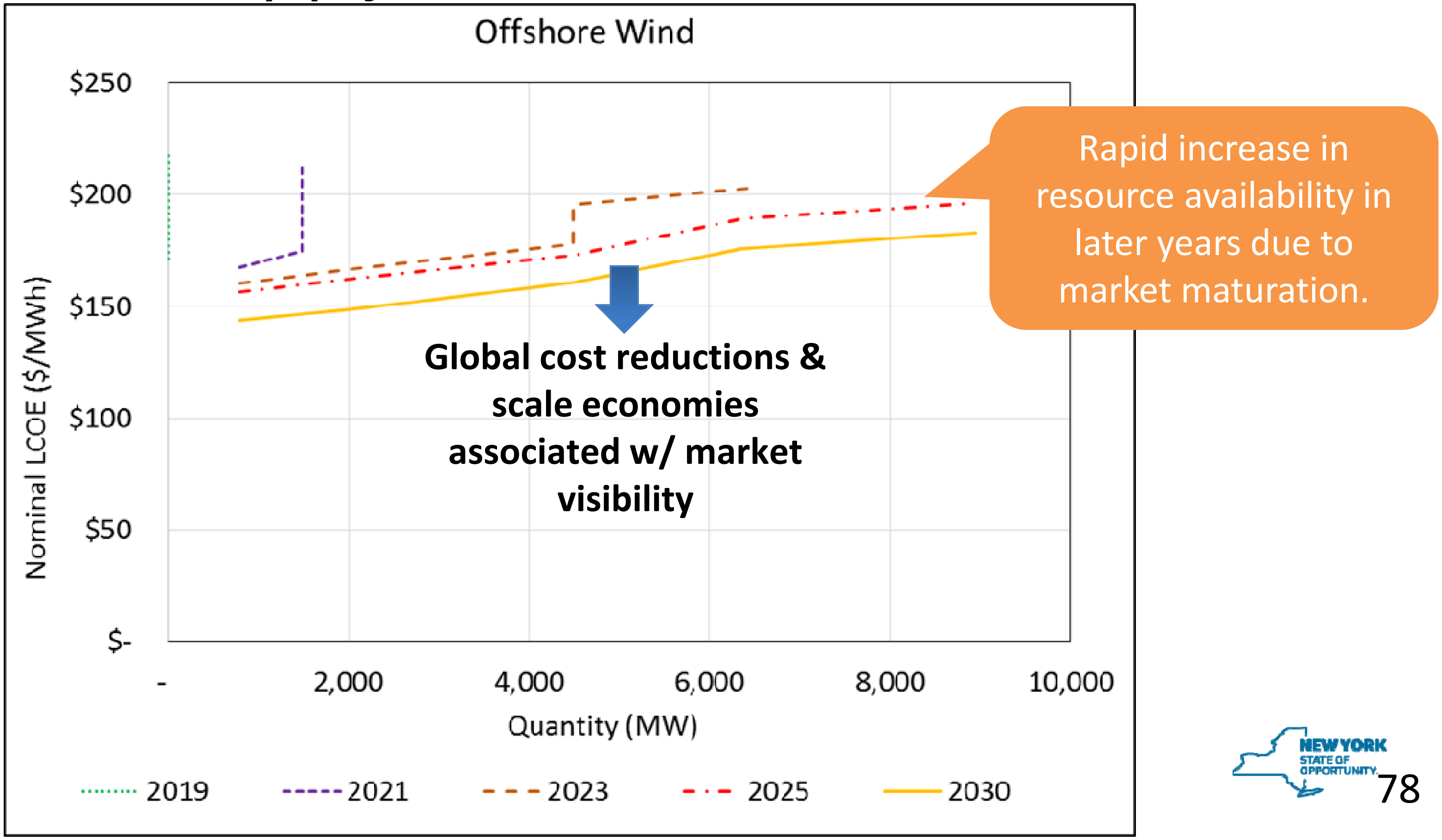
The 2017 c.f.s for each site, modeled by AWST, are as follows:

- Site 1 – 43.6%
- Site 2 – 44.01%
- Site 3 – 44.83%
- Sites 5 & 6 – 44.52%



The starting points were trended with a technological advance index developed by first taking the average of the c.f. trajectories (Mid) for TRG 5 and TRG 6 in the 2015 NREL ATB, then converting the trajectory into an index with 2017 as the base.

LCOE Supply Curves – Offshore Wind



Utility-Scale Solar PV

Utility Scale Solar Photovoltaic (PV): Overview of Approach

- Analysis focused on 10-30 MW installations assumed most likely
- Geospatial analysis estimated total developable area
- PV has homogenous costs (other than interconnection) and production ➔ resource blocks aggregated by similar cost characteristics within each NYISO zone

Utility-Scale Solar PV CAPEX (Not Including T&I Cost)

- Baseline CAPEX based on publicly available sources, recent LSR analyses, and interviews with solar developers active (or planning to be active in this scale) in NY

Utility-Scale PV CAPEX Baseline

CAPEX Baseline (2014$/kW$_{DC}$)	2014 CAPEX Baseline	
Technology & Size Category	Base	Conservative
Solar 10-30 MW, Fixed Tilt	$1,423	$1,503
Solar 10-30 MW, Single Axis	$1,843	$1,843

Assumes a lower degree of market maturation; used for the High PV Cost sensitivity scenario.

Reflects regional cost differences in PV development among NY regions

- Locational adjustments applied to the Baselines:

Reflects cost differences of solar siting and permitting between different NY regions and the national average.

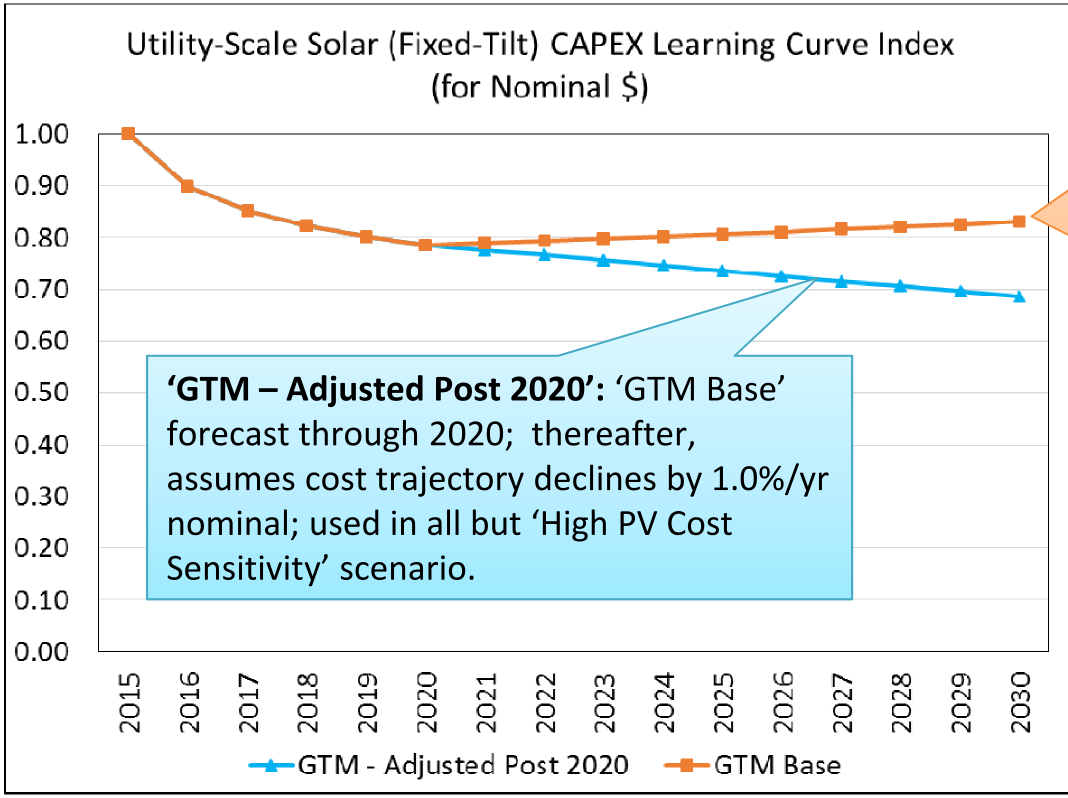
Utility-Scale PV CAPEX Adjustment Factors

[illegible]	[illegible]	EIA Regional Factor	Siting Factor	Final Adjustment Factor
Upstate	A, thru I	0.98	1.00	0.98
NYC	J	1.25	1.02	1.28
LI	K	1.45	1.02	1.48

EIA Regional Factor * Siting Factor

- The capacity & $/kW cost data (CAPEX & Fixed O&M) used are expressed in DC.

Utility-Scale Solar PV Fixed-Tilt Cost Trend



'GTM Base': CAPEX trajectory developed using cost trend published by Greentech Media in November 2015[1]; used through 2030 for 'High PV Cost Sensitivity' scenario.

Graph shows relative cost change compared to start year

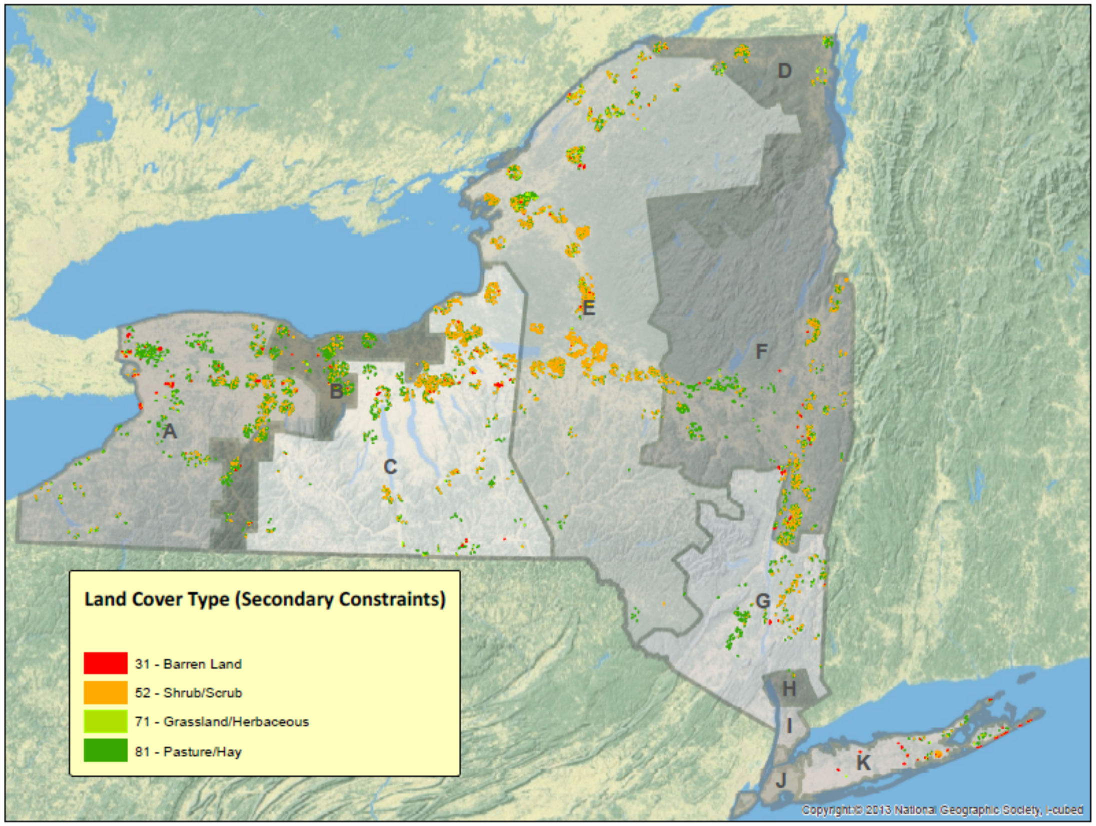
(1) Greentech Media November 3, 2015 Presentation (http://www.greentechmedia.com/articles/read/Slideshow-Reaching-250-GW-The-Next-Order-of-Magnitude-in-US-Solar)

Geospatial Utility-Scale Solar Resource Potential Analysis

Primary Constraints - Excluded Areas	Additional Buffer Beyond Excluded Area
Adirondack and Catskill Parks	100 ft.
National Historic Preserves/Sites/Parks	100 ft.
Wildlife Management Areas	100 ft.
State Unique Area	100 ft.
State and Local Parks	100 ft.
National Monuments	100 ft.
National Wildlife Refuges	100 ft.
National Park Service Land	100 ft.
Fish and Wildlife Service Lands	100 ft.
American Indian Lands	100 ft.
GAP Status 1 & 2 Lands (Protected Lands)	100 ft.
Urban Areas	25 ft.
Forests *	0 ft.
Cultivated Crops *	0 ft.
Wetlands & Waterbodies	100 ft.
Existing Roads and Highways	25 ft.
Airports	25 ft.
Slopes ≥ 5%	N/A

- Primary constraint land areas excluded
- Excluded areas ≥ 2 miles of any roads, ≥3 miles of any existing substations
- Sites requiring interconnection to new substations not considered
- Site resource potential = Site area * Power Density; Power density = 7.5 acres/MW
- Remaining contiguous areas capable of hosting projects ≥ 10 MW considered as potential project sites.

Probability De-rates by Land Cover Type



- Project sites correlated with:
  - Barren Land
  - Shrub/Scrub
  - Grassland/Herbaceous
  - Pasture/Hay
- Only allowed for solar deployment on 25% of 'pasture/hay' area within a site to reflect competing uses

Potential sites shown are result of probabilistic geospatial analysis, should not be interpreted as defining actual project sites

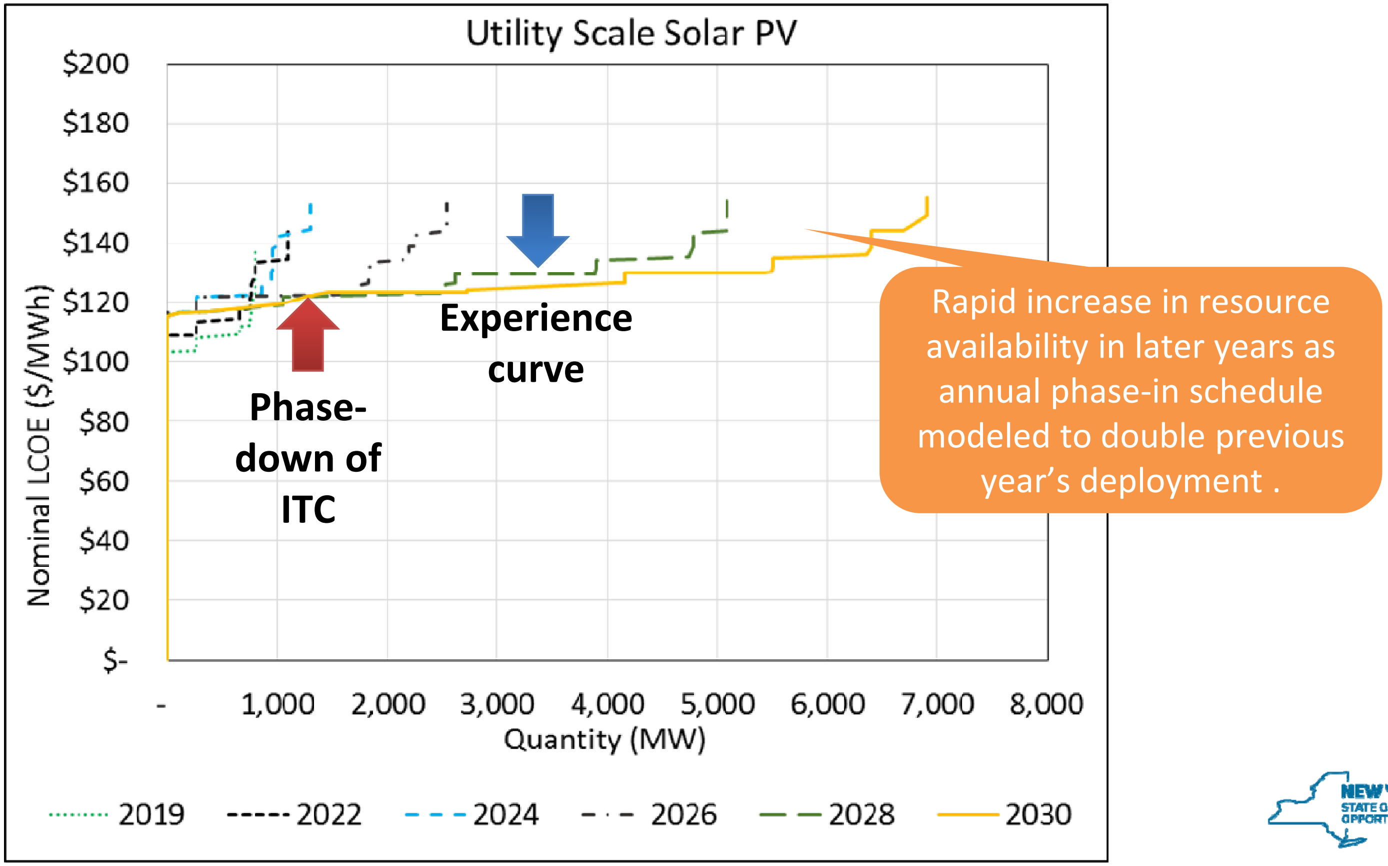
Capacity Factors

Year 1 PV capacity factors (at DC rating) by zone

Zone	Selected Location	Fixed	1-Axis
A	Buffalo	13.7%	16.2%
B	Rochester	13.9%	16.5%
C	Syracuse	14.2%	17.0%
D	Plattsburgh	14.6%	17.3%
E	Utica	12.7%	15.1%
F	Albany	14.6%	17.3%
G	Poughkeepsie	13.3%	15.7%
H	Millwood	14.4%	17.2%
I	Yonkers	15.1%	18.1%
J	New York City	15.4%	18.3%
K	Long Island	14.7%	17.6%

- Year 1 c.f.s derived using PV Watts® at representative NYISO zone based on assumed system characteristics
- Annual production levelized to account for annual production degradation of 0.5%.

LCOE Supply Curves: Utility-Scale Solar PV



Imports

Overview of Approach to LSR Imports

- Resources from adjacent control areas capable of delivering to NY considered ➔ simplified modeling approach
- Focused on resources most likely to export to NY
- Physical transmission inter-ties, competing usage of ties & available space on ties used to estimate assumed practical transfer limits for PPA supply
- Competing native demands and internal transmission constraints in neighboring control areas limit export to NY.
- Additional factors considered in characterizing LSR imports:
    - NYISO delivery zone
    - Potential transaction cost & risks of export/import transaction
    - Electrical losses
    - Potential loss of ability to monetize capacity revenue in exporting market or NYISO

Resources Analyzed in Adjacent Control Areas

Exporting Region	Resource
ISO-NE	Land-based wind
PJM	Land-based wind
Ontario	Land-based wind, small hydroelectric (meeting current RPS eligibility requirements)
Quebec	Land-based wind, small hydroelectric (meeting current RPS eligibility requirements)

- Resource potential and cost analysis of LBW resources performed, similar to analysis for NY LBW resources
- Small hydro resource potential in Ontario from study of incremental potential
  - LCOEs derived using same cost functions applied to NY small hydro supply
  - Carrying charges modified to reflect Canadian depreciation rules & Ontario tax rates.
- Small hydro potential sought for Quebec as well, but ignored (insufficient public data)

Constraints on Out-of-State Resources for CES Tier 1 Supply Curve

- Portion of eastern PJM states' RPS demands assumed met first from supply
- Wind supply from Ohio westward assumed inaccessible (or too costly) to NY due to west-to-east transmission constraints
- Ontario procurement policy demands assumed met first from supply
- Supply from northern and western Ontario limited by material internal transmission constraints, further blocked from getting through Toronto area
- New England LSR supply excluded (strong demands, substantial current & proposed flow of supply from NY to New England)

MW Available over NY Interties at least 85% of hours per year

MW available for at least 85% of hours in year, based on 2014-2015 usage, assumed practical limit to imports.

	ISONE-NYISO	NPX-1385	NPX-CSC	HQ-NYISO	HQ-Cedars	IMO-NYISO	PJM Neptune	PJM NYISO	SCH-HQ Import Export	SCH PJM VFT	SCH PJM HTP
2014	950	8	-	-	-	453	-	1,460	5	65	360
2015	1,128	30	-	-	-	516	-	1,311	-	-	460
Average	1,039	19	-	-	-	485	-	1,385	3	33	410

Key Import Analysis Assumptions

Source Market	Interface	Assumed NYISO Delivery Zone	Assume Practical Transfer Limit for PPA Supply (MW)	Market Adjustment Factor	Assumed Max Imports (MW)	Cost of Importing Power (2015 $/MWh)	Losses (to the extent applied outside of LMP pricing) (%)	Incremental Native Demand (MW)
ISO-NE	ISONE-NYISO	F	1,039.2	0%	-	$ 1.30	0.0%	all
	NPX-1385	K	19.0	0%	-		0.0%	all
	NPX-CSC	K	-	0%	-		0.0%	all
Quebec (HQ)	HQ-NYISO	D	-	0%	-	$12.50	?	0
	HQ-Cedars	D	-	0%	-	$12.50	?	0
	Champlain Hudson Power Express	F	1,000.0	100%	1,000	$10.20	??	0
Ontario (IMO)	IMO-NYISO	A	484.8	100%	480	$4.20	?	Yes
PJM	PJM Neptune	K	-	0%	-	$12.90	?	Eastern
	PJM NYISO	A, C	1,385.3	100%	1,390	$9.20	0.0%	Eastern
	SCH PJM VFT	J	32.5	0%	-	$9.20	2.5%	Eastern
	SCH PJM HTP	J	410.0	100%	410	$21.00	1.9%	Eastern

Small Hydroelectric

Overview of Approach: Hydro

- Costs & resource potential based on:
  - literature review of Idaho National Engineering and Environmental Laboratory (INL), Oak Ridge National Laboratory (ORNL), & U.S. Department of Energy
  - interviews with developers active in NY hydro market
- Hydro cost characteristics extremely site- & size-sensitive ➔analysis uses central estimates
- Categories meeting RPS MT eligibility (<30 MW, or no new impoundment)
  - ✓ **Upgrades** of existing generation facilities
  - ✓ New generation at **Non-Powered Dams** (NPD)
  - No data available on **repowering of existing dams** due to lack of public data, despite some indication of development activities in NY ➔ (grouped in INL & ORNL studies?)
  - **Run-of-river/in-stream** *assumed not commercial before 2030*

Woody Biomass

Overview of Approach: Incremental Biomass

- Resources included:
  - Repowered operating/retired fossil-fueled plants to dedicated biomass-to-energy
  - Greenfield dedicated biomass integrated gasification combined cycle (IGCC)
- Resources excluded:
  - Direct fire/fluidized bed biomass (unlikely to be permittable or economic)
  - Co-firing @ coal-fired plants (Gov. Cuomo's intent to retire all NY coal-fired plants)
  - New & existing combined heat and power (CHP) (simplification)

Biogas

Overview of Approach

- Focused on anaerobic digestion at waste water treatment plants (WWTPs)
- ➔ other biogas resources assumed eligible for Tier 1 not modeled (high costs, relatively small quantities, technologies not yet fully commercial)
- 34 WWTP facilities with design flows of ≥20 MGD studied (79% of treatment capacity in NY) ➔ facilities at this scale have potential for higher quantities of biogas production larger electric generation capacities