Quantitative Analysis of Resource Adequacy Structures

PREPARED FOR
NYSERDA and NYSDPS

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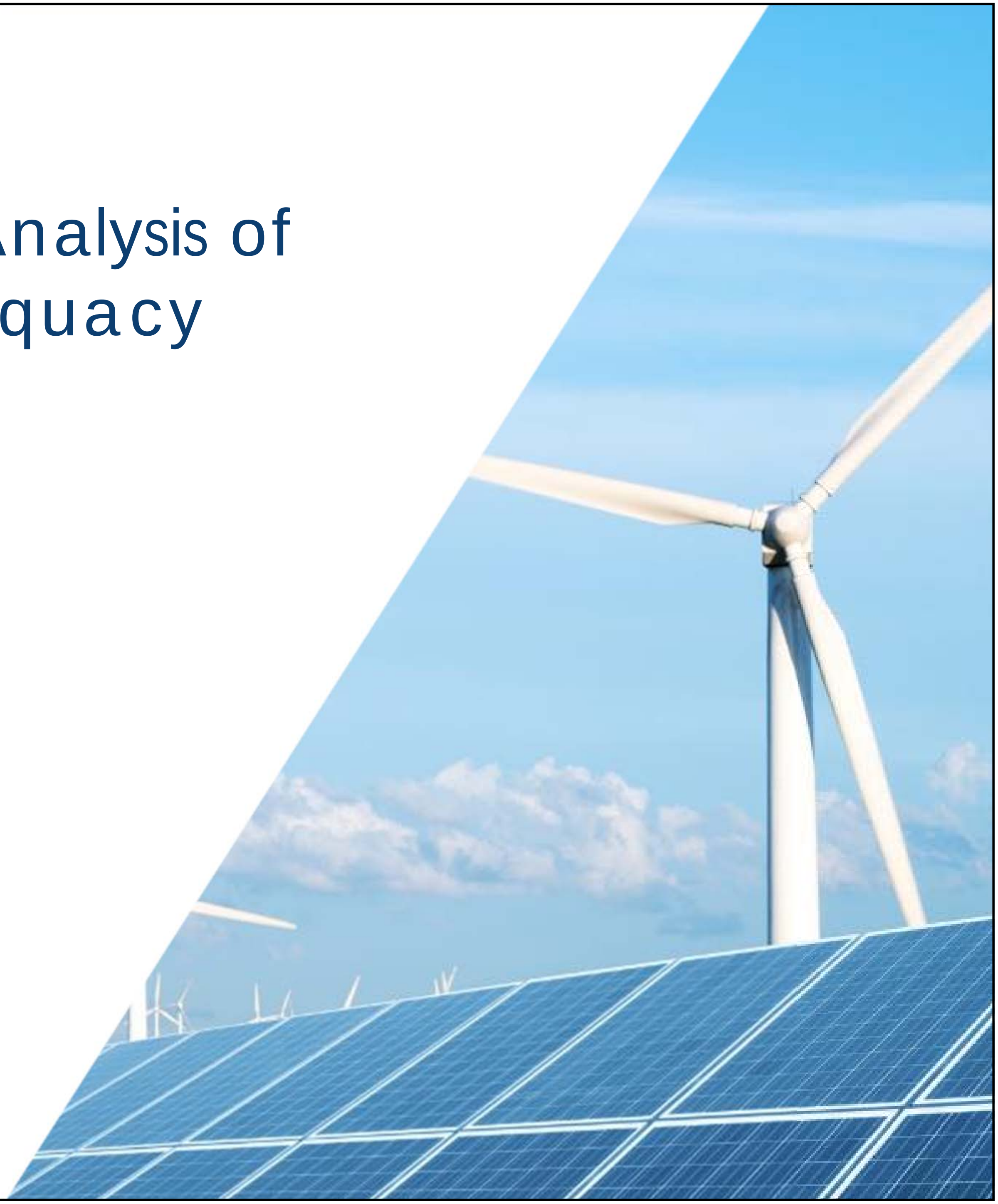


Study Scope

NYSERDA and NYDPS retained Brattle to evaluate several alternative resource adequacy constructs that differ primarily in who administers them and how Buyer-Side Mitigation (BSM) is applied; this deck presents estimates of the differences in customer costs.

Summary of RA Structures Corresponding to Brattle Qualitative Analysis Memo

	Structure	Description	Cost Evaluation
1	**ICAP Market with Status Quo BSM**	Current ICAP market with current rules	Compared to #3 to indicate costs of Status Quo BSM
2	**ICAP Market with Expanded BSM**	Same as above but with potential expansion to BSM rules corresponding to FERC's December 2019 order for PJM	Compared to #3 to indicate costs of potential Expanded BSM
3	**Centralized Market for Resource Adequacy Credits (RACs), without BSM**	Functionally similar to current ICAP market, but with rule-setting by State No BSM, except as applied by PSC to prevent the intentional introduction of uneconomic capacity to profitably suppress capacity prices	Evaluated as "No BSM"
4	**LSE Contracting for RACs**	Same as #3, but with no centralized market LSEs must procure sufficient RACs bilaterally	Similar to #3 but difficult to quantify
5	**Co-optimized Capacity and Clean Energy Procurement**	Same as #3, but a State entity would procure RACs and RECs for LSEs in a joint, co-optimized auction	Not evaluated (out of scope)

Approach and Key Assumptions

To estimate customer cost impacts, we simulated future wholesale markets (including the application of BSM) in 2030, using Brattle's GridSIM model. Key Assumptions:

- Modeled fleet reflects the **Climate Leadership and Community Protection Act** (CLCPA) and **NYISO CARIS study**:
  - 70% of load is met by renewable resources by 2030 (does not include Nuclear generation)
  - Annual gross load, 6100 MW of offshore wind (OSW), 3000 MW of storage, and 7500 MW of behind-the-meter (BTM) solar assumptions consistent with CLCPA targets and 2019 CARIS study assumptions
- Assumptions on BSM applicability were provided by the State Team in consultation with Brattle
  - 1. "Status Quo" applies BSM to new renewables and storage in Zones G-J, except 816 MW Zone J OSW and 184 MW Zone GHI PV
  - 2. "Expanded BSM" extends BSM to all zones, incl. nuclear and half of the existing hydro resources (assuming CapEx projects)
  - 3. Centralized RAC Market w/ "No BSM" does not exclude any resources from the capacity market
- Assumptions on UCAP ratings of intermittent resources affect the magnitude of BSM
  - Marginal value declines with penetration; analyzed output vs. net load to estimate effective load-carrying capability (ELCC)
  - Available output data had low CF% and output diversity, making impact estimates conservative; on the other hand, analysis does not recognize that transmission constraints could make the local J/K value fall faster with penetration
  - Assume resources are paid only the marginal (not average) ELCC, although this does not affect the overall cost of BSM
- Other key assumptions: resources' fixed and variable costs contributing to capacity prices via supply elasticity
- Sensitivity analyses: explored effects of nuclear retirements; higher load

The 2030 system examined here leveraged CARIS 70*30 and otherwise made necessary simplifying assumptions. While the system examined in 2030 does not represent a prediction of the future system, it is a reasonable expectation for the purpose of examining alternative RA structures.

Cost estimates are thus indicative; impact will ultimately depend on the year, supply mix, UCAP ratings, and capacity supply elasticity, and the details of any changes to BSM rules.

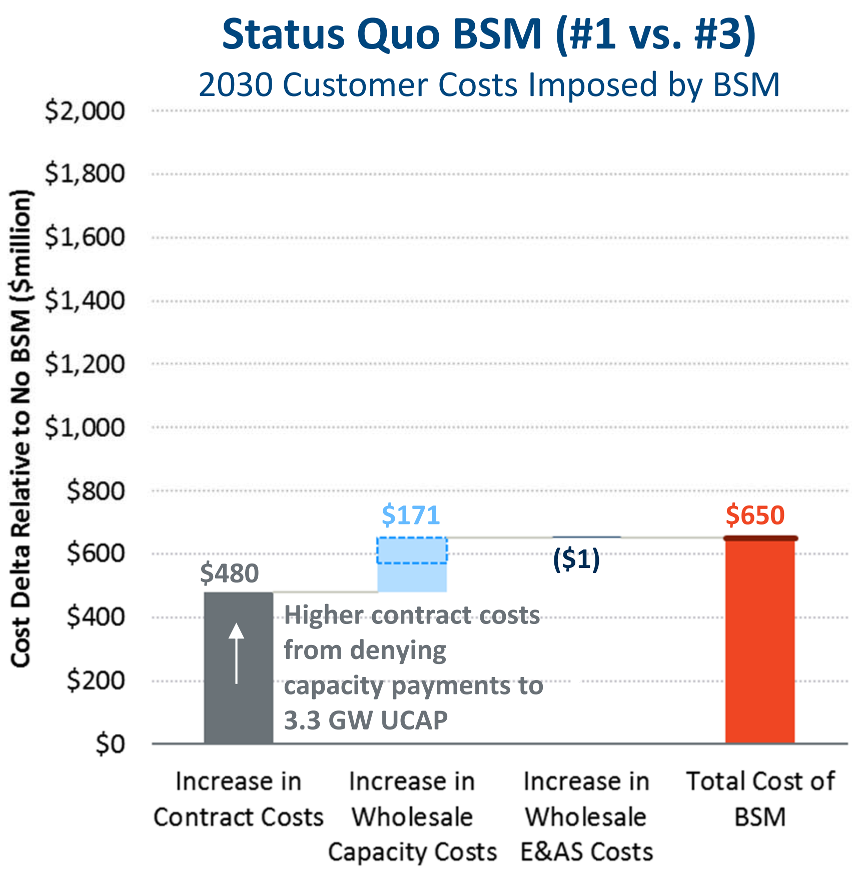
Summary of Conclusions

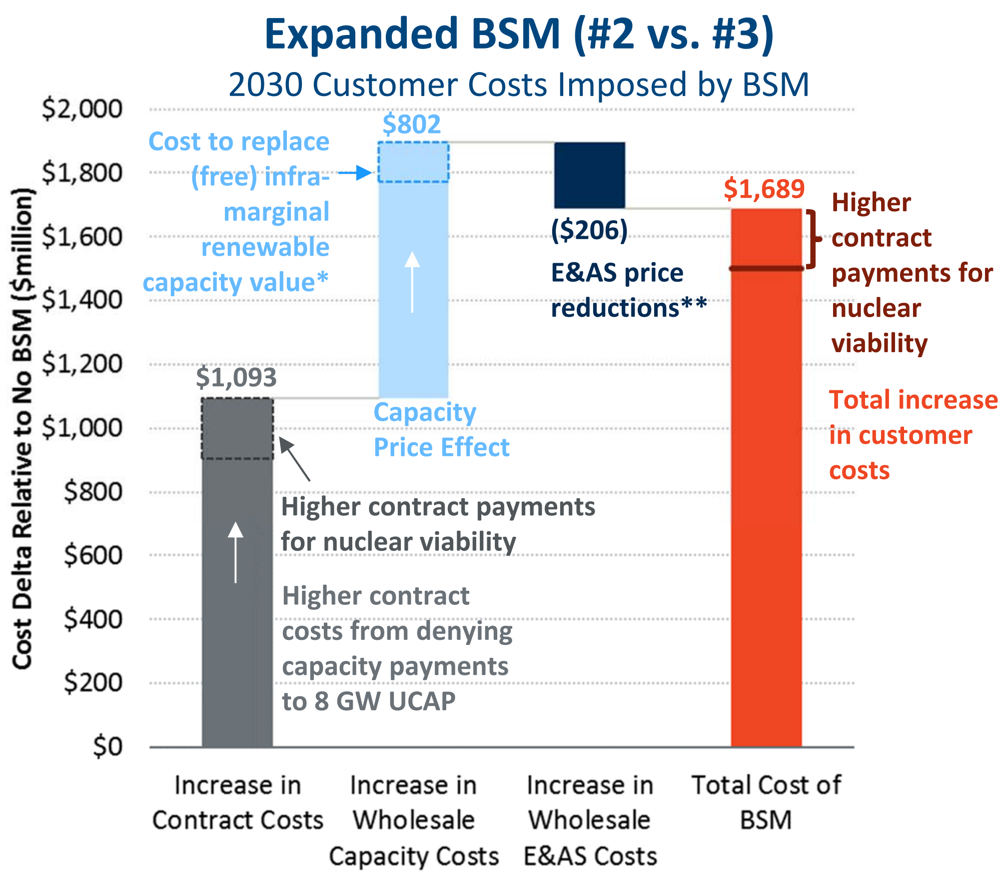
- By 2030 relative to a No-BSM scenario, estimated customer costs increase by:
  - **$0.6-0.8 billion/year** under Status Quo BSM (~17% of capacity costs), with range depending on load growth
  - **$1.7-2.0 billion/year** under Expanded BSM (~47% of capacity costs), or $1.3 billion/year if nuclear plants are retired (~34% of capacity costs)
- This reflects costs of over-procuring capacity because mitigated policy resources would not be accounted for in the capacity market, including:
  - Contract costs increase for policy resources, since they are denied capacity payments
  - Capacity market clearing prices rise
  - Consumers lose inframarginal value of mitigated intermittent resources. Assuming that, absent mitigation, intermittent resources are paid for UCAP given by their *marginal* value on a declining curve even though they contribute a higher average value, mitigating these resources forces customers to buy "replacement" capacity corresponding to the higher average value of the mitigated capacity; hence total impact must reflect average value
- These estimates account for moderating long-term factors:
  - Long-term supply elasticity mitigates capacity price impacts so it is smaller than the "double-payment" quantity effect (showing up as higher contract costs)
  - Lower resource UCAP values at higher penetration of mitigated renewable resources limit the impact
    - Per-MW payments are 14% wind, 14% OSW, 17% PV, and 100% 4-hour storage (summer marginal ELCC); but with foregone infra-marginal value, total customer cost impact of BSM reflects average ELCC, which does not decline as fast as marginal, at 18% wind, 20% OSW, 17% PV, and 100% storage
    - Status Quo subjects 6.2 GW ICAP to mitigation, with 3.3 GW UCAP value (average ELCC); none clears
    - Expanded BSM subjects 15.4 GW ICAP to mitigation, with 10.1 GW UCAP (average ELCC); 8.0 GW does not clear
  - Offsetting E&AS impacts, but these are relatively small

Analytical Results

Estimated Customer Costs of BSM in 2030

Net impact of BSM on customers is $0.7 billion/yr under Status Quo; $1.7 billion/yr under Expanded BSM.



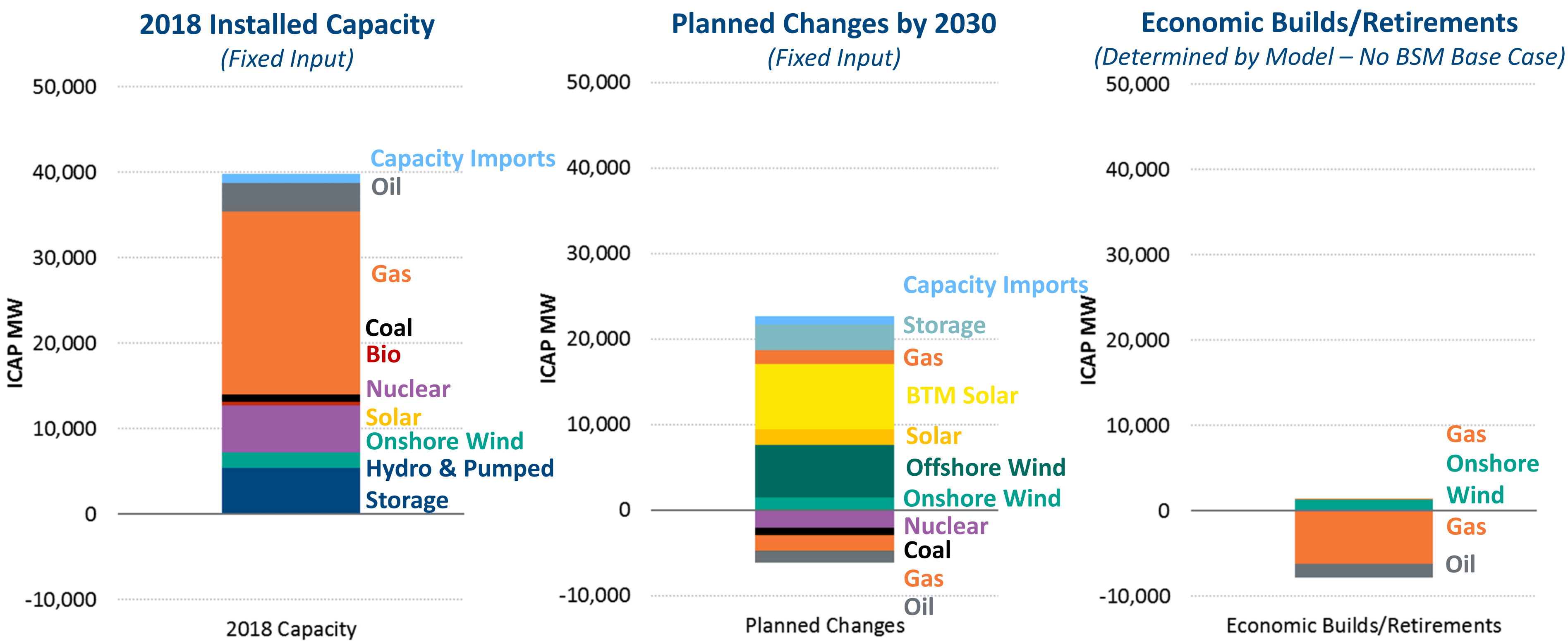


* This assumes resources are paid for marginal ELCC; if they were paid higher average, this value would shift to an increase in contract costs, and BSM's overall impact on customer costs would be the same, assuming the same resources are built.

** Energy and AS prices decrease because excess capacity depresses prices in tight hours; and because higher REC prices (due to lack of capacity payments) cause energy prices to be more negative in over-generation hours.

Base Case Supply Mix

Existing generation is consistent with the 2019 Gold Book, and planned capacity changes are based on signed CES contracts and CARIS study assumptions. The model economically retires old plants and builds new clean ones to meet any remaining gap to reach CLCPA 70% target (see next slide).



Note: Model determines if 2018 existing supply resources will retire by 2030. In No BSM Base Case ~7,800 MW of uneconomic gas and oil resources retire.

Note: Model determines economic resource builds needed to reach CLCPA targets (incremental to planned changes). In No BSM Base Case, ~1,400 MW of additional onshore wind is built to reach 70% target.

Mitigated Capacity by Zone

Mitigated Non-Emitting Capacity by Zone (ICAP MW)

Blue shading subject to Status Quo BSM

Expanded BSM applies to blue and teal

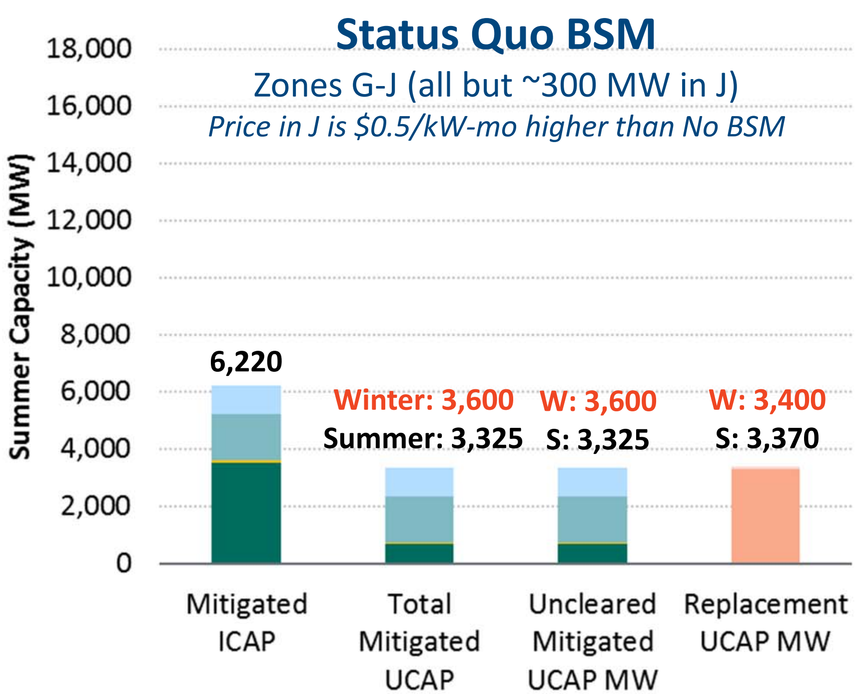
	2018 Capacity	Planned/Assumed 2019-2030 Additions/Retirements (Fixed Input)					Economic Additions (Determined by Model)		Total Capacity by 2030
		Zone A-E	Zone F	Zone G-I	Zone J	Zone K	Zone A-E	Zone F-K	
Hydro & PS	5,436	0	0	0	0	0	0	0	5,436**
Onshore Wind	1,739	1,521	0	0	0	0	1,365	0	4,625
Offshore Wind	0	0	0	0	4,320*	1,778	0	0	6,098
Solar	77	1,587	0	284*	0	0	0	0	1,948
Storage	0	660	240	270	1,350	480	0	0	3,000
Nuclear	5,399	0	0	(2,054)	0	0	0	0	3,345
Capacity Import	1,100	0	0	0	1,000	0	0	0	2,100
Total	**13,751**	**3,768**	**240**	**(1,500)**	**6,670**	**2,258**	**1,365**	**0**	**26,553**

Notes: 2018 installed capacity informed by 2019 Gold Book. Planned/assumed builds are informed by 2019 CARIS study assumptions and signed CES contracts based on 2018-2019 CES contract summary document. Inputs do not reflect recent 2019 Tier 1 solicitation, such that ~1,100 ICAP MW of solar contracted from 2019 solicitation is not included and ~200 MW of onshore wind is classified as economic build instead of fixed input.
*1,000 MW combined capacity exempt in both Status Quo and Expanded BSM (816 MW Zones J and K OSW and 184 MW Zone GHI Solar).
** Half of existing hydro fleet assumed to be mitigated under Expanded BSM.

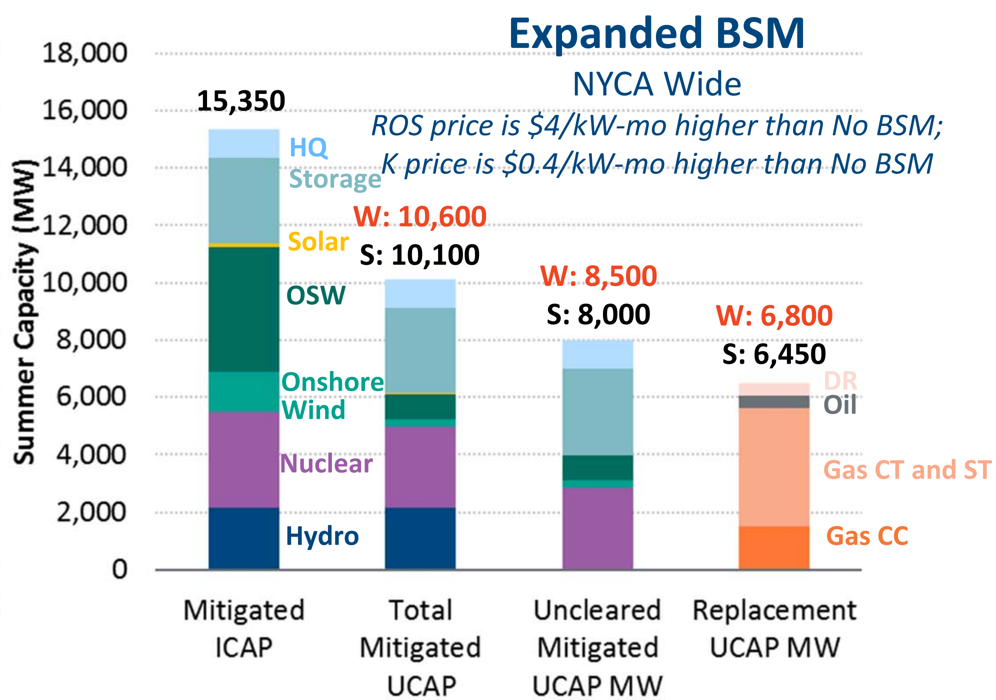
Summary of Mitigation and Market Response Quantities (NYCA-Wide)

In Status Quo BSM, essentially all of the ~3,325 summer UCAP MW uncleared mitigated capacity is replaced by retained gas ST + DR.

In Expanded BSM, ~1,550 summer UCAP MW of the 8,000 summer UCAP MW uncleared mitigated capacity is *not* replaced (mostly Upstate), resulting in a higher capacity prices and costs.



Mitigated capacity in Zones G-J only under Status Quo, mostly OSW and storage in Zone J that is replaced by retained gas ST plants. UCAP values reflect average ELCC, as relevant for total customer cost impact although resources are assumed paid based on a lesser marginal ELCC.



Mitigated capacity in all zones. Mitigated OSW and storage in Zones J and K (1,400 MW ICAP; 600 MW UCAP mitigated in K) largely offset by retained gas resources. All UCAP values shown reflect average ELCC.

Customer Costs & Wholesale Prices

Customer Cost Delta to No BSM

Category	Customer Costs Delta Above (Below) No BSM (2030 $ million) 1. Status Quo	2. Expanded BSM
Wholesale Market Cost	**$170**	**$596**
Energy	($1)	($205)
Ancillary Services	($0)	($1)
Capacity	$171	$802
Contract Costs	**$480**	**$1,093**
ZEC (Current Payment Structure)	$0	$0
Additional Nuclear Payments*	$0	$190
HQ Imports (Zone J)	$184	$191
Offshore Wind	$19	$47
Utility Solar New	$0	$0
Onshore Wind New	$1	$22
Solar BTM	$0	$9
Storage	$278	$409
NY Hydro**	$0	$187
Existing Tier 1 Renewables**	($2)	$37
Total Customer Cost	**$650**	**$1,689**
Excluding Nuclear Make-Whole	$650	$1,499

*Additional payments required to keep nukes online, primarily because energy prices are so low and ZEC payments don't increase accordingly.
**Existing Tier 1 Renewables are resources with signed CES contracts that will still be in effect by 2030. NY hydro assumed to be paid at REC price.

Market Prices Delta to No BSM

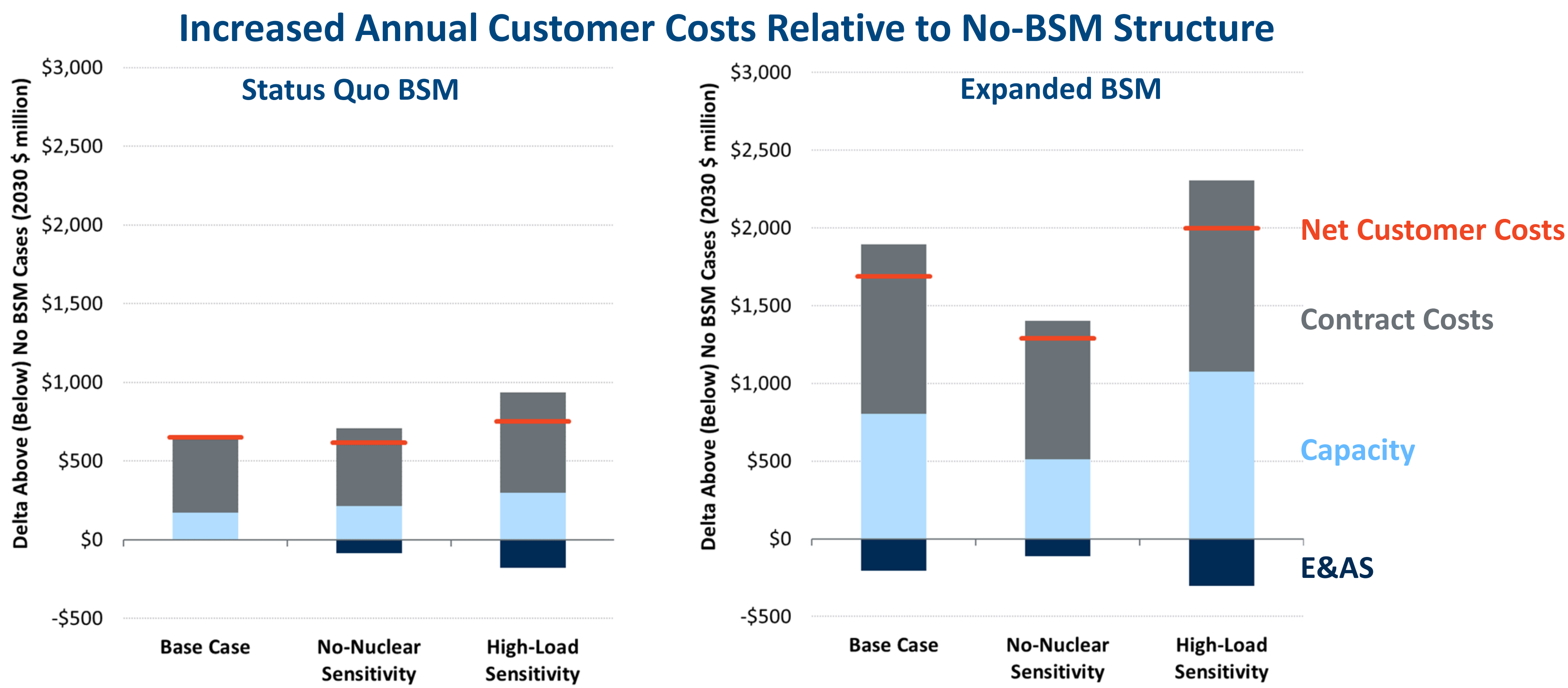
Zone	Capacity Market Prices Delta Above (Below) No BSM (2030 $/kW-month) 1. Status Quo	2. Expanded BSM
A-E	$0.00	$3.88
F	$0.00	$3.88
G-I	$0.01	$0.01
J (NYC)	$0.46	$0.46
K (LI)	$0.00	$0.40

Zone	Energy Market Prices Delta Above (Below) No BSM (2030 $/MWh) 1. Status Quo	2. Expanded BSM
A-E	($0.01)	($1.87)
F	($0.00)	($0.76)
G-I	($0.00)	($0.60)
J (NYC)	($0.00)	($0.60)
K (LI)	($0.00)	($1.11)

Zone	REC Price Delta Above (Below) No BSM (2030 $/MWh) 1. Status Quo	2. Expanded BSM
System-Wide	$0.00	$5.90

Sensitivity Analysis of BSM Costs

Customer costs of BSM are lower in a "No-Nuclear" case and somewhat higher in a "High-Load" case



Notes: "**No-Nuclear Sensitivity**" loses all >3 GW of upstate nuclear, largely replaced by retaining gas CCs, so fewer resources to mitigate.
"**High-Load Sensitivity**" results in 12 ICAP GW (1.2 UCAP MW) of additional solar and onshore to meet 70% target.

Modeling Approach and Assumptions

Brattle GridSIM Model

Inputs

Supply

Existing resources
Fuel prices
Investment/fixed costs
Variable costs

Demand

Representative day hourly demand
Capacity needs

Transmission

Zonal limits
Intertie limits

Regulations, Policies, Market Design

Capacity market
Carbon pricing
Procurement mandates

GridSIM Optimization Engine

Objective Function

Minimize NPV of Investment & Operational Costs

gridSIM

Constraints

- Market Design and Co-Optimized Operations
  - *Capacity*
  - *Energy*
  - *Ancillary Services*
- Regulatory & Policy Constraints
- Resource Operational Constraints
- Transmission Constraints

Outputs

Annual Investments and Retirements

Hourly Operations

System and Customer Costs

Supplier Revenues

Emissions and Clean Energy Additions

Market Prices

Demand Assumptions

- "Base Load" load assumptions align with 2019 CARIS study input assumptions for 2030
- "Base Load" assumes lower demand than 2019 (156 TWh gross load)
- Modeled "High Load" based on State Team input that assumes greater load than 2019

2030 Demand Assumptions

	Base Load	High Load
Scenarios	Base Case No-Nuclear	High-Load
Annual Gross Load	145 TWh	169 TWh
Gross Peak Load	30 GW	35 GW
Net Peak Load	28 GW	33 GW

Sources and Notes:

"Base Load" annual gross load assumptions are based on 2019 CARIS study. Used ratio of 2019 annual gross load and CARIS annual gross load to convert 2019 gross peak loads to 2030 gross peak loads on zonal level.

"High Load" annual gross load assumptions based on State Team's input. Calculated peak loads based on annual gross load ratio as described above.

Netted out assumed 7,542 MW of solar BTM (based on 2019 CARIS study) valued at ~27% summer capacity value from gross peak load to calculate net peak load (similar to Gold Book assumptions).

2019 load data taken from NYISO OASIS data.

Supply Cost Characteristics

- **Resources' fixed O&M costs** affect supply elasticity and BSM price impacts. Sources:
  - *New Gas CCs, CTs*: 2019 costs from Demand Curve Reset (DCR); decline rate from 2019 NREL ATB (0% to -2%/year real)
  - *New Gas STs*: 2019 costs and cost decline rate from 2019 NREL ATB (0% to -1%/year real)
  - *New wind, solar, storage*: 2019 costs and cost decline rate from 2019 NREL ATB (0% to -7% /year real)
  - *Existing Nuclear*: 2019 costs from NEI (constant real), plus assumed $280/kW-year refurbishment cost adder in 2030
  - *Existing thermal*: FOM assumed 2x that of new
  - *All other existing:* Same FOM as new resources
  - *Zone J and K*: FOM assumed 1.3 – 2x higher than upstate based on DCR zonal cost ratios
- **Offshore wind** tied to either zone J or K
- **Utility-scale PV and onshore wind** cannot be built in zones J or K

2030 Resource Cost Assumptions

	Upstate New Resource Capital Cost *2030$/kW*	Upstate New Resource FOM *2030$/kW-yr*	Upstate Existing Resource FOM + Refurb Costs *2030$/kW-yr*	Variable O&M *2030$/MWh*
Natural Gas				
Combined cycle	$2,100	$26	$52	$2
Combustion turbine	$1,100	$14	$27	$7
Steam turbine	$5,000	$43	$85	$11
Battery Storage				
4-hour duration	$1,100	$26	$26	$6
Solar PV				
Utility scale	$1,100	$13	$13	$0
Wind				
Offshore (downstate)	$4,600	$107	$107	$0
Onshore	$1,600	$50	$50	$0
Nuclear				
Single-unit	N/A	N/A	$602	$3
Multi-unit	N/A	N/A	$491	$3

Sources and Notes:

Includes interconnection and network upgrade costs. NREL 2019 ATB, NYISO DCR Model 2019-2020, and NEI Nuclear Costs in Context.
VOM for storage resources reflect efficiency losses. Existing FOM for nuclear includes refurbishment costs.
FOM costs for existing thermal resources were assumed to be 2x that of comparable new ones, informed by EPA Integrated Planning Model document.
Nuclear refurbishment costs informed by refurbishment costs for nuclear plants in Ontario.

ELCC Modeling Approach

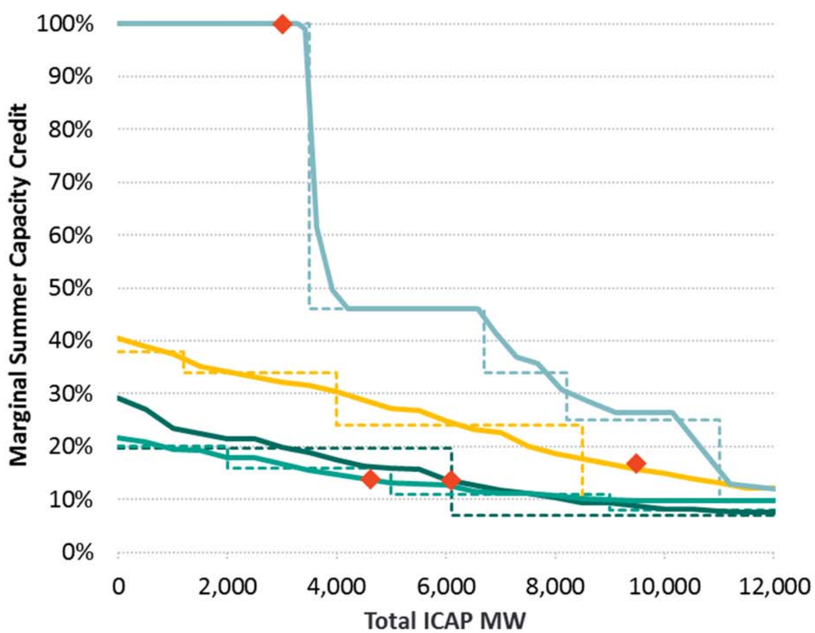
Supply Resource	Concept	Methodology
Wind and Solar Resources	Generation of new wind and solar additions is correlated with previously deployed resources. New resources therefore provide less marginal capacity value than previously added resources.	1. Across 8760 hours, identify 100 top NYCA net load hours 2. Calculate wind UCAP value as avg. output in those hours 3. Repeatedly change the MW of wind installed, all else equal 4. Each time, find top 100 net load hours and the avg. output 5. Repeat process for offshore wind and solar; for each one, hold other variable technologies at likely 2030 levels
Storage Resources	Energy storage can change the "shape" of peak net load periods, flattening and elongating peak periods. As more storage is deployed, longer discharge durations are therefore required to provide the same capacity value.	1. Across 8760 hours, analyze MW of storage required to reduce NYCA net peak load by 1 MW 2. Calculate UCAP value as 1 MW peak reduction / MW storage required 3. Increase amount of storage assumed, holding all else equal. Simulate effect of increased storage on net peak load 4. Repeat steps 1 – 3 across many storage deployment levels 5. Repeat process for storage of different durations

Base Case UCAP Value Curves
modeled based on NYCA-wide net load

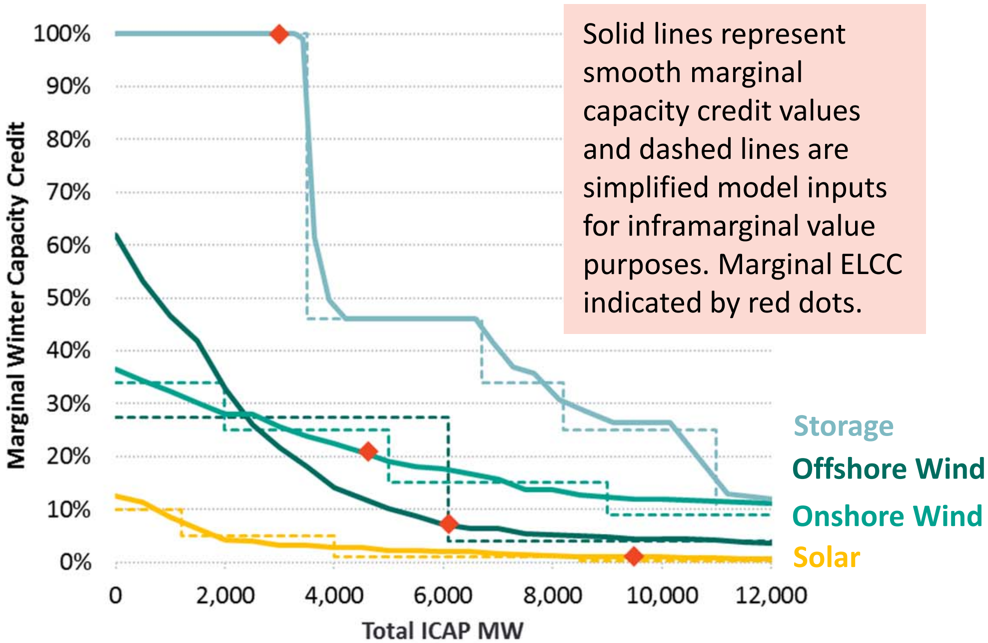
As the penetration increases, marginal effective load-carrying capability (ELCC) decreases.

Note: this analysis may have conservatively low ELCCs for renewables, based on hourly data with lower output than future installations are likely to achieve (and that does not capture diversity across sites for OSW); on the other hand, this analysis uses NYCA-wide net load without considering how transmission constraints could reduce value more quickly.

Summer UCAP Value



Winter Capacity Value



Note: solar capacity credit curves include assumed 7,542 MW of solar BTM already on the grid (based on CARIS study assumption).

Assumptions on BSM Applicability

Resource Type	BSM in Structure 1. Status Quo		BSM in Structure 2. Expanded BSM	
	Zones G-J	**Rest of System**	**Zones G-J**	**Rest of System**
Nuclear	N/A	N/A	N/A	3,345 ICAP MW
OSW	3,504 ICAP MW (assume 816 ICAP MW of already signed contracts exempt)		3,504 ICAP MW (assume 816 ICAP MW of already signed contracts exempt)	898 ICAP MW (assume 880 ICAP MW of already signed contracts exempt)
Existing Solar and Onshore Wind	100 MW solar (assume contracts already signed benefit from a single 1,000 MW renewable exemption, mostly used up by 816 MW OSW)		100 MW solar as in Status Quo (FERC exempted existing resources in PJM)	No
New Utility Scale Solar and Wind	Any new utility scale solar or onshore wind in Zones G-J		All new utility scale solar and onshore wind	
Bulk Storage	1,620 ICAP MW		1,620 ICAP MW	1,380 ICAP MW
Existing Hydro	No		50 ICAP MW	2,085 ICAP MW
Tier 2 Renewables	No		No	No
New HQ Imports	1,000 MW in Zone J		1,000 MW in Zone J	N/A
Demand Response	No		No	No
Fossil Resources	No		No	No

Source: Assumptions on applicability provided by NYSERDA/DPS staff. Status Quo assumptions were established while 1,000 MW renewables exemption was pending at FERC, while SCRs were exempt from BSM and before Part A changes were filed at FERC. Due to the outstanding rehearing requests and the uncertainty of FERC action on those filings, those assumptions were not changed. See parallel Qualitative Analysis.

Contract Cost Accounting Assumptions

Category	Resource Type(s)	Customer Cost Calculation Method
Index REC contracts*	HQ Imports: Zone J via CHPE	Bundled energy, capacity, REC contract; subject to BSM. Contract price based on costs of new hydro + transmission line and size of capacity rating in Zone J (1000 MW summer UCAP, 1310 MW ICAP), minus energy and capacity revenues
	Offshore Wind, new onshore wind, new utility-scale solar	Resource fixed cost minus capacity revenues and net E&AS revenues. If they do not clear the capacity market then their capacity revenue is zero
Other Renewables Contributing to 70% by 2030	Distributed solar	Resource fixed cost, minus energy revenue (capacity value is already accrued to customers via reduced capacity procurements)
	Existing (Already Contracted) Tier 1 renewables	REC price × energy production
	NY hydro	REC price × energy production
Storage	Storage up to 3,000 MW	Resource fixed cost minus capacity revenues and net E&AS revenues. If they do not clear the capacity market then their capacity revenue is zero
ZEC	Nuclear	ZEC = $19.59/MWh − Max{0, Zone A energy price + RoS capacity price − $39/MWh} Assume top-up payments for uncleared capacity

* Mitigated resources that are not cleared in capacity market are assumed to be made whole via higher contract prices.

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