JOINT UTILITIES
OF NEW YORK

Value of Distributed Energy Resources Technical Conference

April 5, 2017

NYSEG nationalgrid Orange & Rockland Rockland Electric Company conEdison People. Power. Possibilities. Central Hudson A FORTIS COMPANY RG&E

Agenda

• DRL/LSRV	10:45am – 12:15pm
• Cost Recovery/Allocation	12:15pm – 1:30
• Break (lunch)	1:30pm – 2:15
• ICAP	2:15pm – 3:30
• MTC and Rules	3:30pm – 5:00

DRV / LSRV

Distribution System Value

- Primarily driven by Peak Load Growth and the impact on distribution system and local transmission
- Distribution System Wide Peak Load Growth Differs by Utility
- Load growth occurs in pockets and LSRV can help target that growth
- The number of locations applicable for LSRV will differ by utility
- The value assigned to locations will vary by location and by utility based on cost for upgrades

Status of DRV / LSRV

- Each Utility has filed MCOS study
  - MCOS utilized to develop DRV values
  - MCOS utilize different underlying methodologies
  - DRV represents a weighted average of all locational areas

- Development of LSRV
  - Utility planning processes and risk criteria that trigger the need for reinforcements may differ by company, as a result, the approach initially employed to estimate LSRV will vary among the utilities

- Future MCOS and application for DRV and LSRV
  - Methodology should become more uniform
  - Methodology should be flexible enough to allow for different utility characteristics
  - Additional Steps are required to develop LSRVs

Central Hudson: MCOS Methodology

- Probabilistic load forecasting methodology for granular transmission areas and substations
- Analyze load patterns, excess capacity, load growth rates, and the magnitude of expected infrastructure investments at a local level
- Develop location specific forecasts of growth with uncertainty
- Quantify the probability of any need for infrastructure upgrades at specific locations
- Calculate local avoided T&D costs by year and location using probabilistic methods
- Identify beneficial locations for DERs

Central Hudson: MCOS methodology

- 10 distinct transmission areas
- 54 distribution load serving substations
  - Some substations either lacked data or had lower quality data and, as a result, we were unable to estimate location specific forecasts for all substations
  - The substations lacking hourly data are generally smaller stations serving relatively few customers.
  - The portion of the system where detailed hourly data was available, accounted for 89.5% of Central Hudson's 2016 peak

Central Hudson

- DRV for CH based on most recent MCOS = $14.55
- 5 Areas – two transmission/3 distribution or substation growth areas
- Preliminary Locational Values based on MCOS study
  - RD-RJ Line $58.05 kW-year (transmission)
  - WM Line $102.11 kW-year (transmission)
  - Hunter $31.46 kW-year (Substation) (Winter Peaking)
  - Lawrenceville $275.34 kW-year (Substation) (Winter Peaking)
  - Coldenham $119.91 kW-year (Substation)
  - 8 transmission areas $0 kW-year
  - 50 substations areas $0 kW-year

Central Hudson

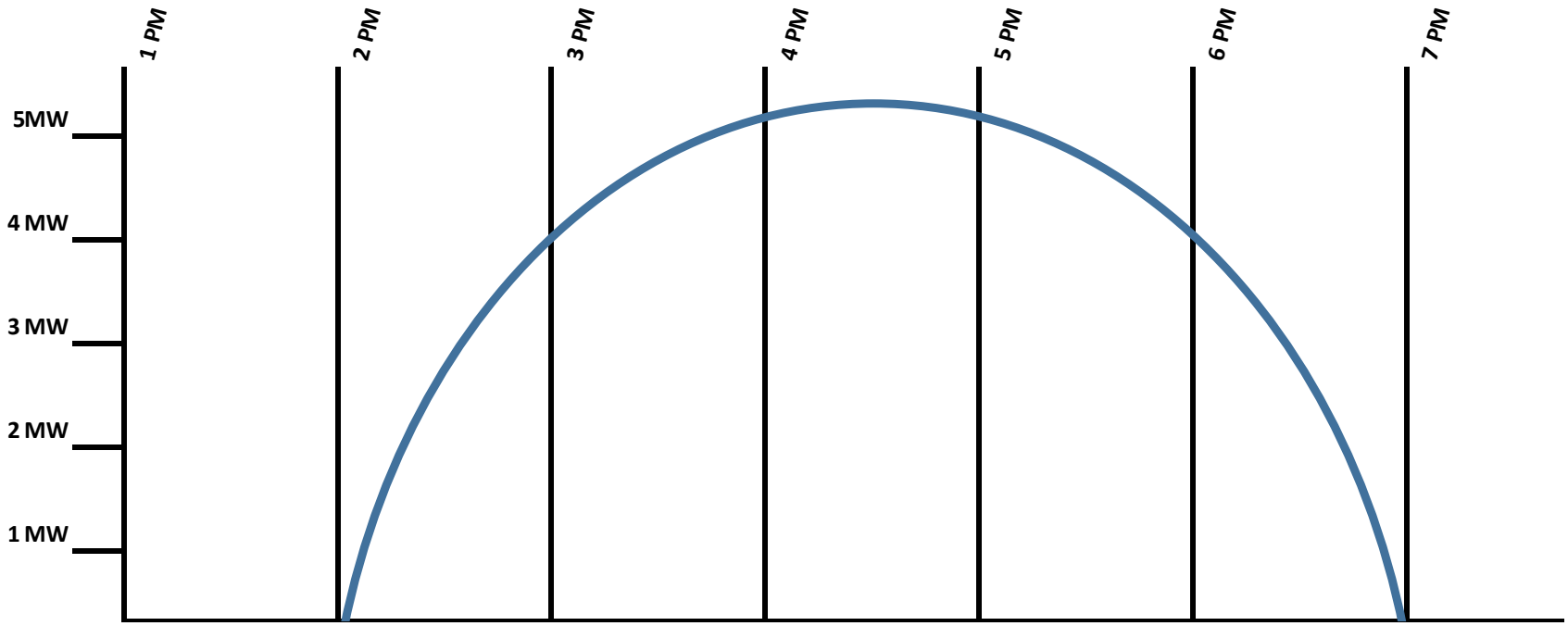
- DRV MCOS caveats that cause LSRV development to require further steps

Implementation of low cost short term options	Potential need based solely on load forecast does not automatically trigger need for expensive system upgrades. In many cases lower cost interim solutions exist
Defined MW need	Simplifying assumptions in calculating the avoided cost were used
Performance requirements of DER	analysis does not put any constraints or performance requirements on the DERs
Appropriate avoided cost value	In developing location specific values, the avoided costs would need to be devalued since paying the full avoided costs to DER providers would result in no net savings for customers

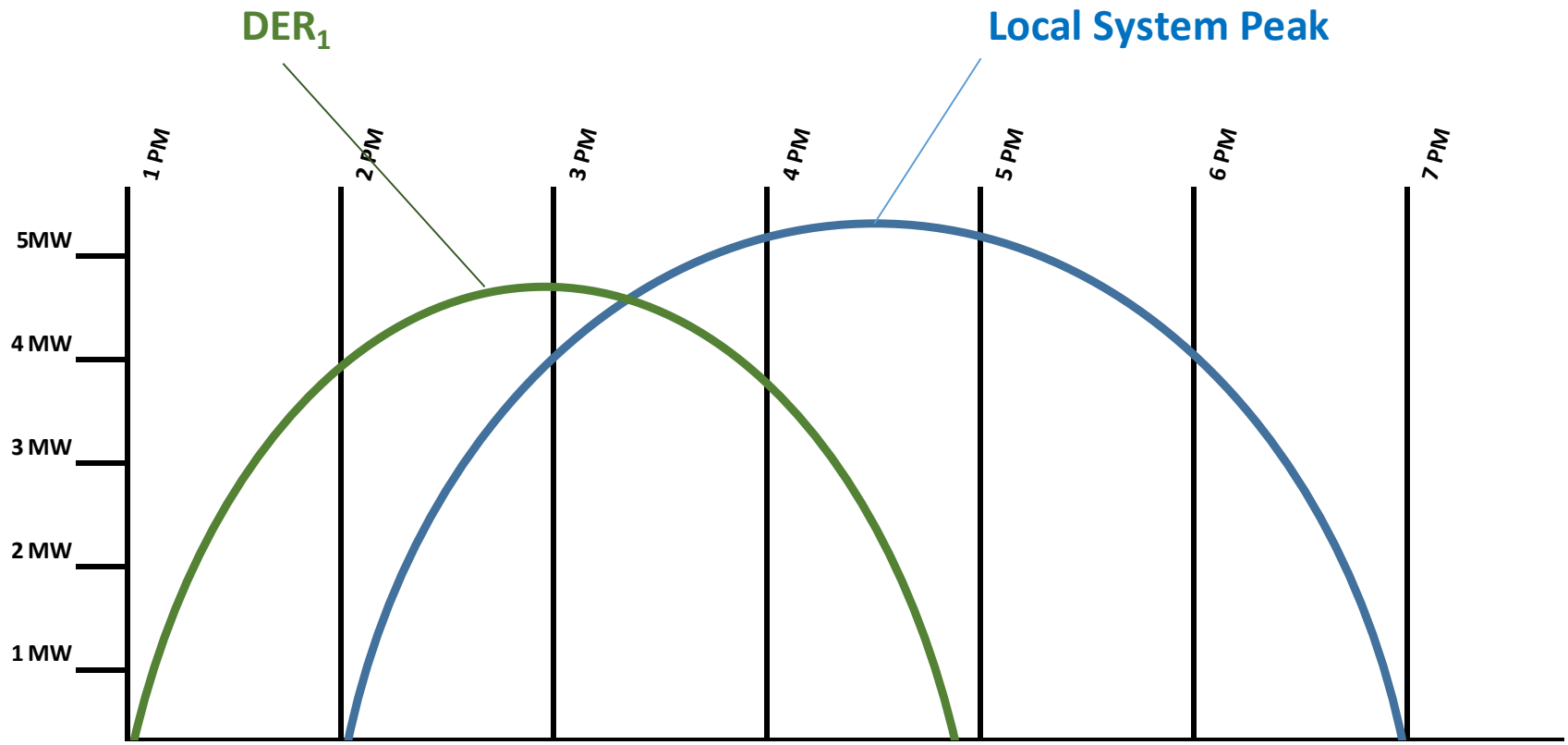
Distribution Value Relationships

- DRV is a weighted average of locational values
  - DRV – used as an input in BCA
    - DLM and Energy Efficiency Programs
  - Development of NWA or LSRV causes DRV to decrease
- MW applicable for LSRV capped based on MCOS
- Within LSRV - DER characteristics need to be considered and compared to locational load profile
  - May result in different MW caps
  - May result in different $/kW-year
- Update LSRV and DRV more frequently than every three years to tie to NWA and DLM Tariff changes

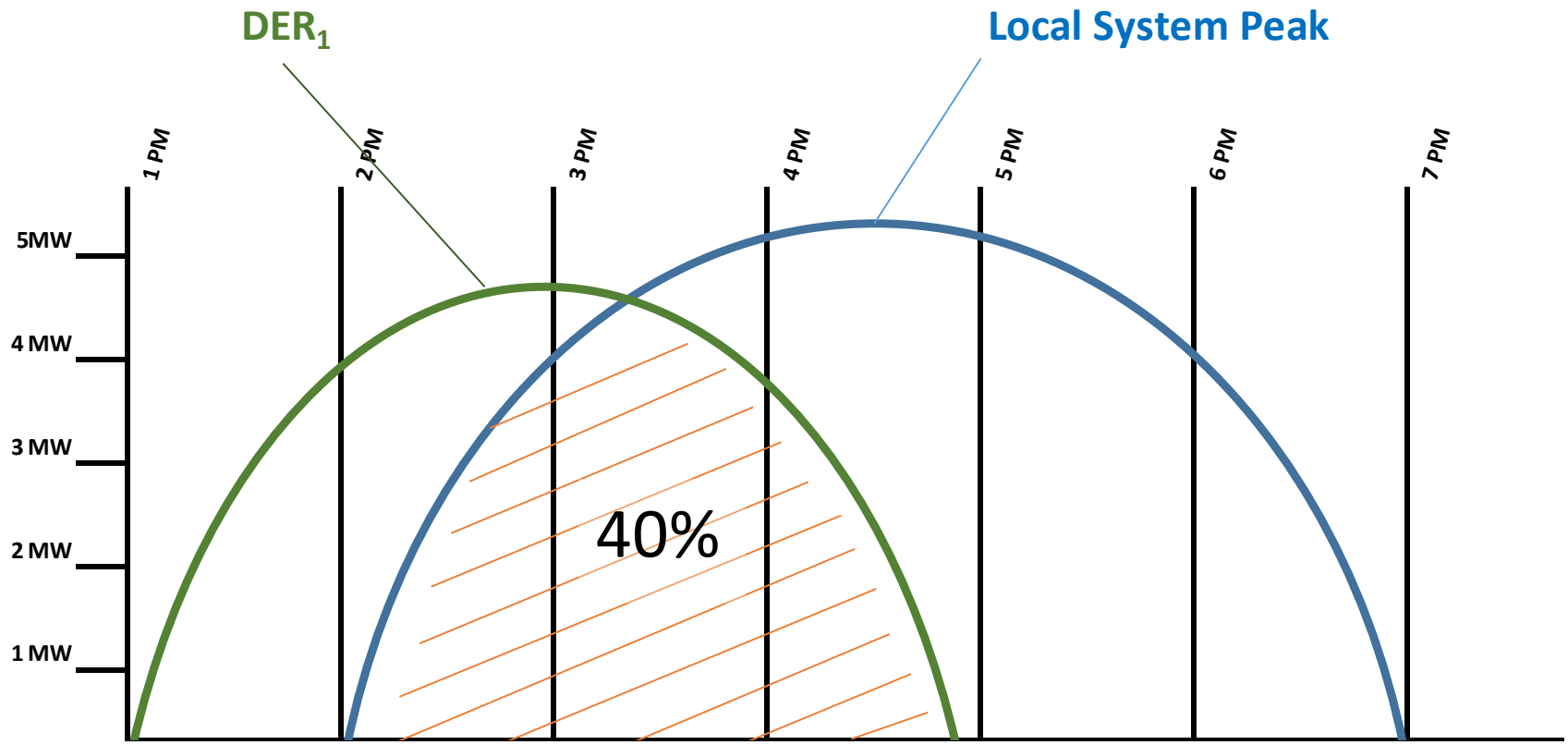
Hypothetical Peak



Hypothetical DER Coincidence



Hypothetical DER Coincidence



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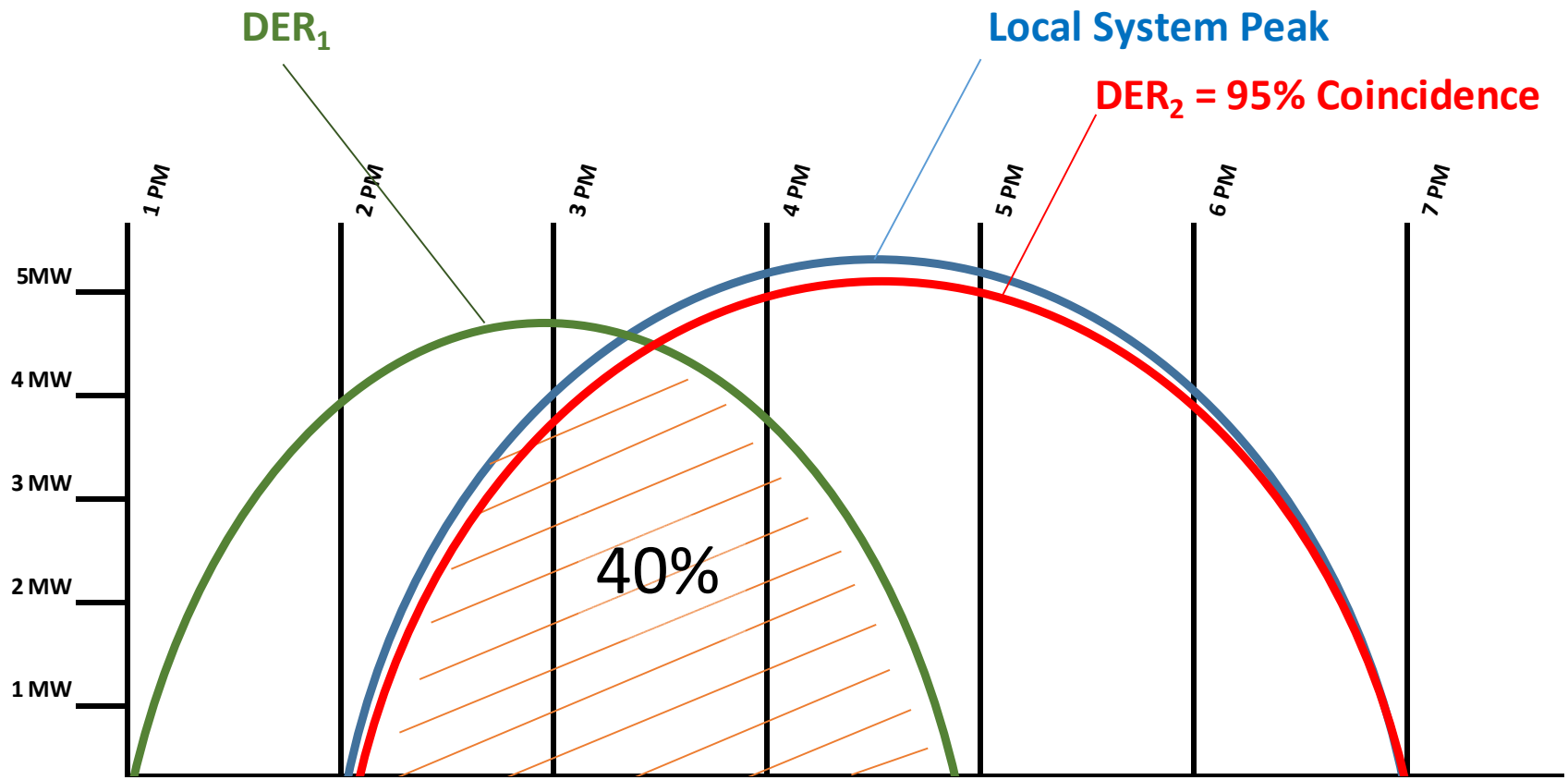
Hypothetical DER Coincidence



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LSRV - DER characteristics

- All hours of the peak are necessary to achieve goal of MCOS
- MW Cap – potential scenarios
  - MW Cap based on DER technology
  - MW Cap may be broken down hourly based on local area load profile
- $/kW pricing differential - scenarios
  - Some DER resources may have less value based on production capability
  - Some Hours may have less value based on available supply of resources
- Need Input and need to work within time and complexity constraints

Con Edison/O&R: Current MCOS methodology

- Analysis was done using a design engineering approach
- Study identifies transmission and distribution needs that cannot be met with excess capacity.
- For load growth in areas with excess capacity the marginal cost is zero.
- System Weighted Marginal Costs combined the costs for network and non-network areas
  - Estimates not historically made specific to particular networks
  - In non-network areas, secondary costs received a zero weight since these facilities are designed with short-term excess capacity

Con Edison/O&R: Current MCOS methodology

- Transmission – Switching Stations – Area Stations
  - Study assigns zero marginal costs in years of excess capacity until capacity is absorbed by load growth
  - Identifies the load-carrying capability of each project and the date when a new station is added
  - Incorporates reserve capacity concept
  - Compute $/kW of load-carrying capability for each project from approximately two years prior to the need date and then going forward
- Primary Feeder – Transformers - Secondary Cable
  - Examined a sample of jobs that upgraded and added primary, transformer and secondary facilities
  - For each job, the MC was determined per kW of added design capacity - second contingency, where applicable

Con Edison LSRV Criteria

- Determined by MW reduction required to achieve lower % Loading

Level of system	Loading Threshold
Sub-transmission	98% Loading
Area Station	98% Loading
Network	90% Loading

Con Edison has identified high-value areas, 85MW of LSRV caps

LSRV MW caps by area of need

Sub-transmission	MW Cap
Plymouth	14.3
Water St.	30.1
Glendale, Newtown	8.1

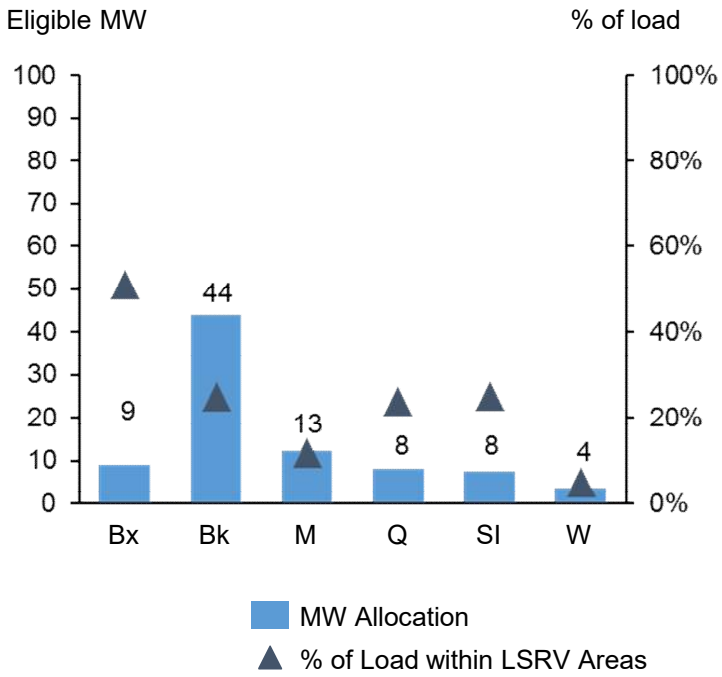
Each sub-transmission path has 1-3 area stations where DER can be located

Area Station	MW Cap
East 179th Street	7.8
Parkchester No. 2	6.8
Parkchester No. 1	0.7
W. 65th St. No. 1	1.5
Wainwright	7.2
Willowbrook	0.3
Millwood	3.8

Each Area Station has up to 2 load areas where DER can be located to solve the station need

Network	MW Cap
Northeast Bronx	6.8
Yorkville	4.5

LSRV MW caps by region



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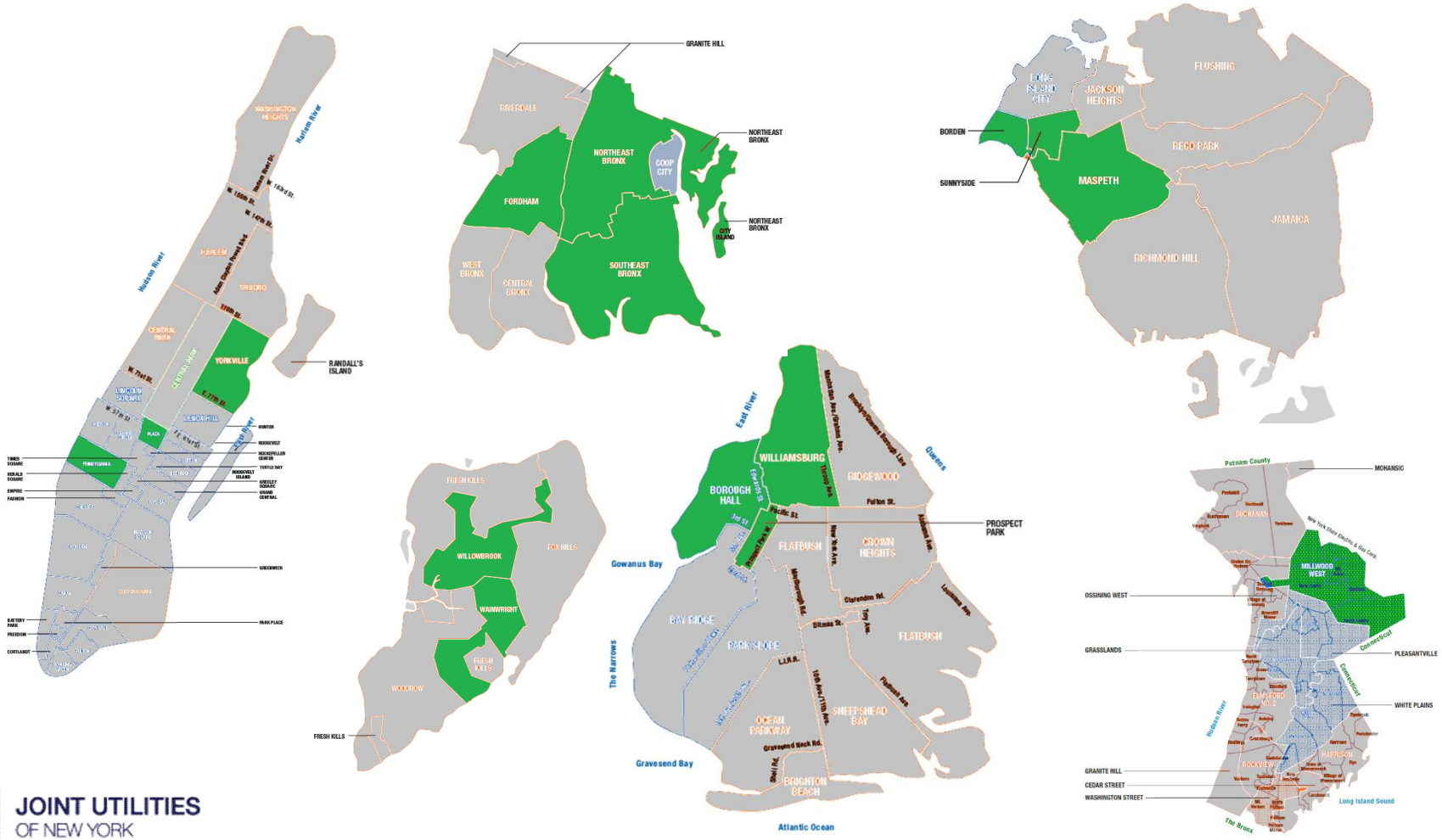
20% of Con Edison load is in a high-value area

- This load is eligible for LSRV



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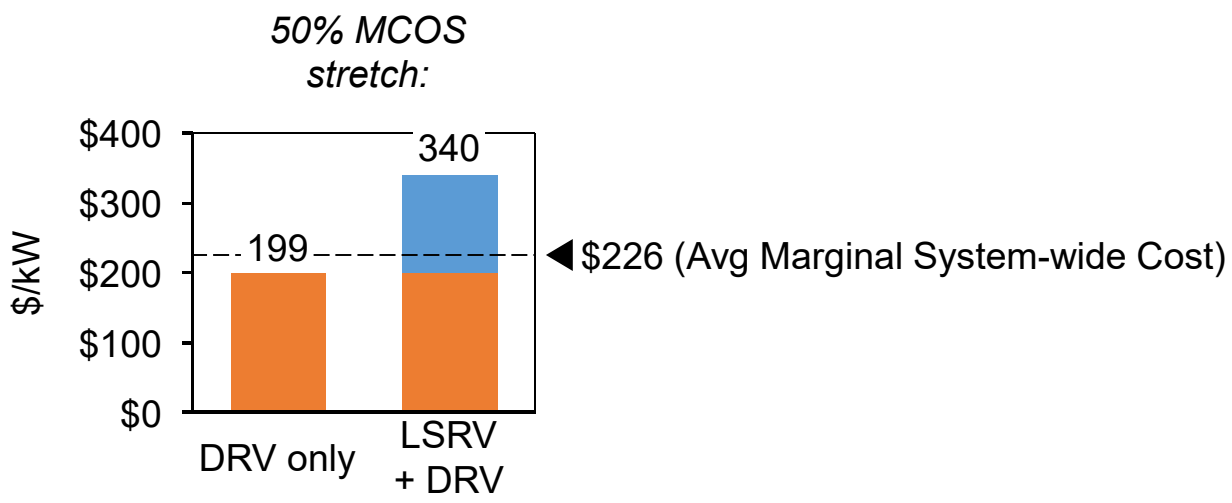
Con Edison: LSRV and DRV Rates

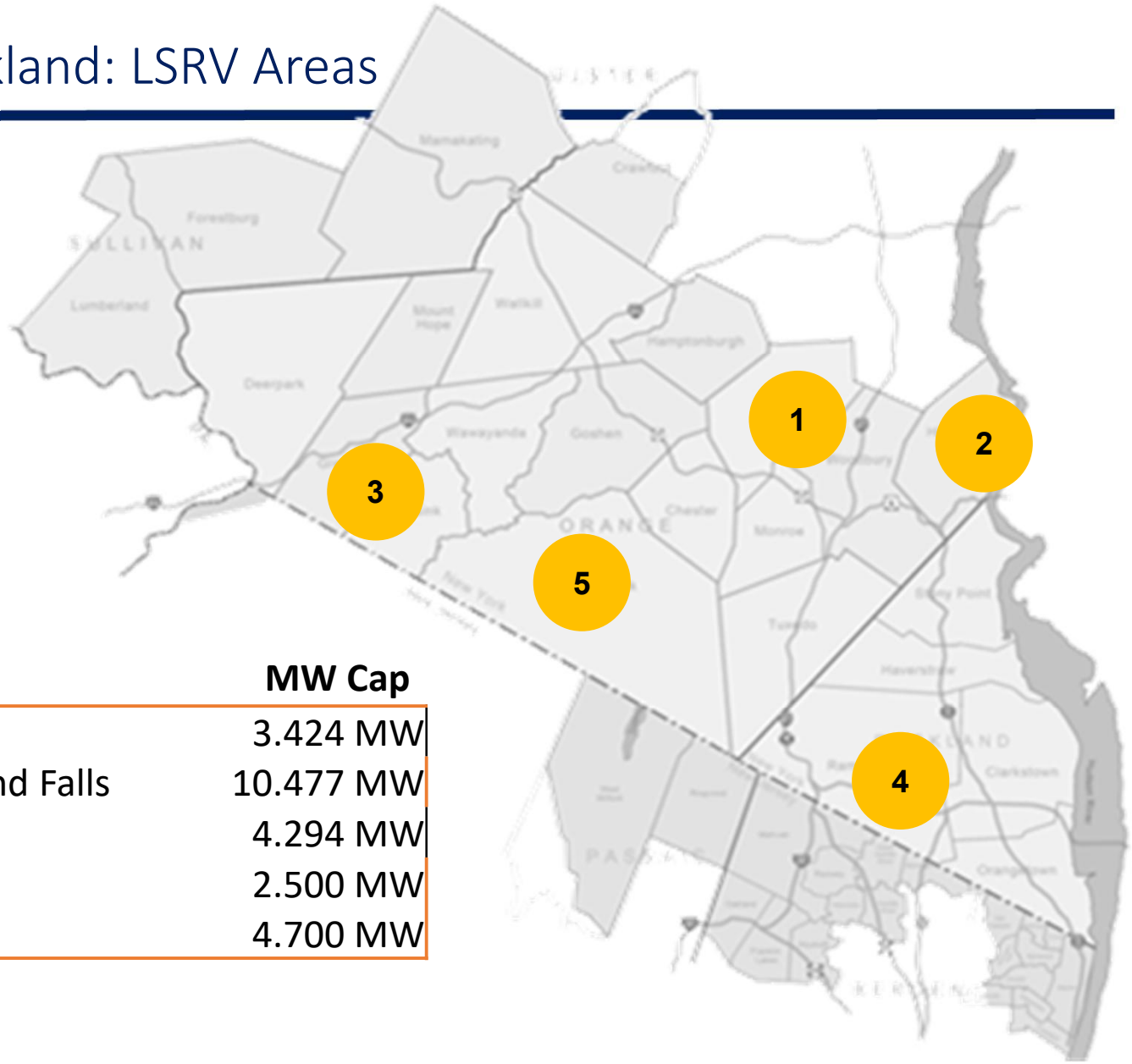


Values Based on Typical Solar Production	11A-3P CSRP Window	2P-6P CSRP Window	4P-8P CSRP Window	7P-11P CSRP Window
Coincidence with Peak	47%	32%	13%	12%
Expected DRV ($/kWh)	.069	.047	.019	.017
Expected LSRV + DRV ($/kWh)	.117	.081	.032	.029

Orange & Rockland: LSRV methodology

- Examined areas with planned investments reflecting load and contingency needs
- MW caps are the amount of reduction required to reach normal ratings or operational needs
- DER additions in these areas would be beneficial to customers
- Eligible areas reflect 12% of NY load and 13% of NY customers

Orange & Rockland: LSRV Areas



		MW Cap
1	Blooming Grove	3.424 MW
2	Harriman & Highland Falls	10.477 MW
3	Port Jervis	4.294 MW
4	Monsey	2.500 MW
5	Wisner	4.700 MW

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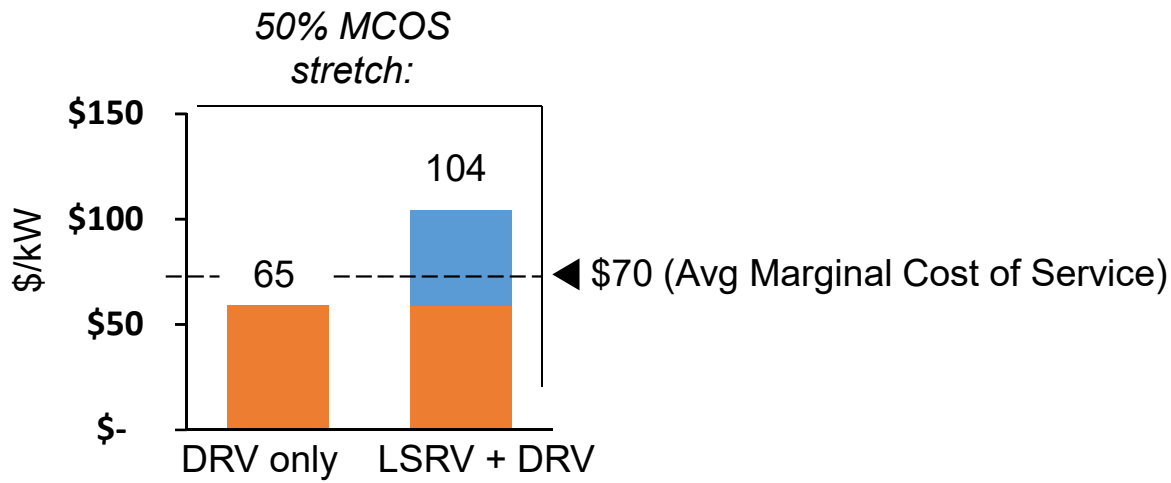
Orange & Rockland: Illustrative LSRV and DRV Rates



Area	MW Cap	Coincidence with Peak	Expected DRV ($/kWh)	Expected LSRV + DRV ($/kWh)
Blooming Grove	3.424	18%	$0.0084	$0.0135
Harriman & Highland Falls	10.477	18%	$0.0084	$0.0135
Port Jervis	4.294	18%	$0.0084	$0.0135
Monsey	2.500	18%	$0.0084	$0.0135
Wisner	4.700	18%	$0.0084	$0.0135
TOTAL	**25.4 MW**			

National Grid – Current MCOS Methodology

- MCOS Demand is computed using an economic approach
- Examine a sample of jobs that added capacity
  - Sample is judgmentally drawn from Company records, but with no statistical or engineering analysis
  - Project cost divided by kW added = Marginal Capital Cost per kW
  - Separate samples for Transmission and Distribution; Distribution further detailed by Residential, URD and Commercial
  - We do not separate costs into Demand and Customer (i.e., cost to connect regardless of demand) components
  - Add capital costs for Transformers
- Convert capital costs to annual costs
  - How much do we need to include in the revenue requirement including depreciation, return on rate base plus income taxes, O&M costs, A&G costs, indirect plant
- We also compute Marginal Customer costs
  - Capital costs for Services and Meters
  - Converted to annual costs, as for Demand costs discussed above
  - Also add Billing and other customer-related costs

- MCOS is the cost to add capacity. Does not identify *where* we need to add capacity; for a non-constrained area the marginal cost is zero, but if that area becomes constrained then the marginal cost would apply

National Grid – Identifying LSRV Areas

- Preliminary Methodology
  - Basis for identifying LSRV areas
    - Identify areas at substation level
      - Considering alternative aggregation levels (e.g. distribution planning areas or higher)
  - LSRV areas selected as those expected to reach 100% of substation planning capacity by 2020
    - Basis for MW Caps
    - Caps set to bring load down to 95% of planning capacity or the forecasted light load at the substation, whichever was less
    - Methodology for identifying MW caps does not take hosting capacity into account; hosting capacity may vary by location on the circuit/feeder

National Grid – Identifying LSRV Areas Cont.

- Preliminary number of unique locations and MW Caps
  - 62 (of 576) substations identified as potential LSRV areas
    - 62 substations represent approximately 20% of total system load
    - Some substations identified overlap with potential NWA areas
  - Sum of MW caps at identified substations is 193 MW

National Grid – Deaveraging MCOS

- Preliminary Methodology
  - Deaverage algebraically:
    - Identify percentage by which to inflate the MCOS to arrive at the LSRV
    - Pull the number of LSRV areas out of the system average MCOS
    - Recalculate non-LSRV system average MC to arrive at DRV
    - The weighted average of the LSRV & DRV by number of locations is equal to MCOS

  For example…

National Grid – Deaveraging MCOS Cont.

- Example LSRV/DRV Calculation:

	Total # of Substations	576
	# of LSRV Substations	62
	System Average MCOS	$66.48
	LSRV Inflate %	50%
	LSRV	$99.72
Deaveraging Calculation	MCOS	$66.48
	x Total # of Substations	576
		$38,292.48
	LSRV	$99.72
	x # of LSRV Substations	62
		$6,182.64
		$38,292.48
		-$6,182.64
	Numerator for Non-LSRV Areas	$32,109.84
	/ # of Non-LSRV Substations	514
	DRV	$62.47

			# of Substations	
DRV	$62.47	x	89.24%	$55.75
LSRV	$99.72	x	10.76%	$10.73
Weighted Average = System Average MCOS :				$66.48

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National Grid – LSRV & DRV Variables

- Under preliminary deaveraging methodology, LSRV, DRV, and the delta between them change with changes to:
  - The number LSRV areas
  - The percentage increase in the LSRV over the MCOS

  For example:

		LSRV Inflate Percentage			
	($/kW-yr)	25%	50%	75%	100%
62 LSRV Areas	LSRV	$83.10	$99.72	$116.34	$132.96
	DRV	$64.48	$62.47	$60.47	$58.46
	Δ	$18.62	$37.25	$55.87	$74.50
31 LSRV Areas	LSRV	$83.10	$99.72	$116.34	$132.96
	DRV	$65.53	$64.59	$63.64	$62.70
	Δ	$17.57	$35.13	$52.70	$70.26

NYSEG/RG&E – Marginal Cost Methodology

- Forward-looking concept based on utility planning process
- Measures how a small change in consumption affects utility system costs
- Costs measured for three elements of electric distribution service:
  - Customer-related costs:
    - Costs that vary with number of customers on system
    - e.g. meters, services, customer-related expenses
  - Design-demand related costs:
    - Costs for facilities that are sized based on the expected maximum loads of customers using them over life of the equipment
    - e.g., transformers, local primary lines, secondary lines
    - Expectation that facilities will not be expanded in response to month-to-month or year-to-year variations in actual usage
  - Load-related costs:
    - System elements that must be expanded as system peak load grows (i.e., depends on customers' ongoing changes in electricity use and timing of use within the day)
    - e.g., distribution substation, trunkline feeders, upstream line and substation, transmission
    - Distribution components time-differentiated
    - Marginal transmission cost based on each Company's Transmission Service Charge (TSC)

NYSEG/RG&E – LSRV Criteria

- Currently based on NWA projects filed in 2016 Distributed System Implementation Plan
- NWA analysis applied BCA Criteria to distribution projects solving system capacity constraints
- LSRV Areas
  - Preliminarily 5 at NYSEG and 2 at RG&E to support these projects:

Company	Project Name	Division
RG&E	Station 117 - Replace #1 Transformer Bank and convert 3 circuits to 12kV operation	Rochester
RG&E	Station 46 - Replace #1 and #3 Transformer Banks	Rochester
NYSEG	Crafts - Add 2nd Transformer and 4th 13.2kV Circuit Position	Brewster
NYSEG	Hilldale 115kV source, xfrmr bank upgrade, 2nd 12kV dist circ	Liberty
NYSEG	Holland Transformer Replacement	Lancaster
NYSEG	Orchard Park - Add a 2nd Transformer Bank	Lancaster
NYSEG	West Davenport Sub - Replace sub transformer with non-LTC 7.5/10.5MVA unit.	Oneonta

- Preliminary analysis shows LSRV rates as between $9 kW/year and $86 kW/year based on current MCOS studies

NYSEG/RG&E - DRV

- Current MCOS values:
  - NYSEG $30.84 kw/year
  - RG&E $31.58 kw/year
- Preliminary DRV values after LSRV calculation:
  - NYSEG $30.35 kw/year
  - RG&E $31.92 kw/year
- Future Activities:
  - Develop Deaveraged Marginal Study
  - Analyze previous NWA/LSRV projects to see if still viable
  - Identify locations (circuits) associated with each LSRV project

Cost Recovery/ Allocation

Cost Recovery/Allocation

- NEM Methodology
  - Delivery Charges
    - Reconciled via RDM at Service Class level
  - Surcharges
    - Shortages are reconciled via all delivery customers that pay the surcharge
  - Supply
    - Any cashout at avoidable costs is considered a supply cost and is included in each utility's electric supply reconciliation method
    - This may differ by utility

Cost Recovery/Allocation

<u>Cost Allocation Principles (pg 17 of order)</u>

- Costs associated with compensation under the VDER Phase One tariff will be collected, proportionately, from the same group of customers who benefit from the savings associated with the compensated DER
- For compensation that does *not* reflect a value that has been identified and calculated at this time, recovery will come from customers within the same service class as the beneficiaries

Cost Recovery/Allocation

- Phase One NEM Methodology same as NEM for qualifying projects:
  - On-Site Mass Market
  - On-Site Large Projects
  - Remote Net Metering Projects
  - CDG Tranche 0

Cost Recovery/Allocation

- Cost Recovery Principles for Value Stack
  - Costs follow benefits
- Value Stack Components and Market Transition Credit
  - Energy
  - Capacity
  - Environmental Credit
  - Demand Reduction Value (DRV)
  - Locational System Relief Value (LSRV)
  - Market Transition Credit (MTC)

Cost Recovery/Allocation: Energy

Description in Order	Day Ahead Hourly LBMP including losses (hourly metering of exports is required)
Calculation Methodology	Volumetric hourly exports multiplied by zonal LBMP grossed up for applicable losses
Reason for Compensation	Offsets utility energy purchases otherwise made through NYISO
Who Pays and Why	Default supply customers since this is a purchase power cost
Recovery Mechanism	• Component of the supply charge • Each utility has a different mechanism intended to cover supply purchase reconciliations
Potential Issues	• Losses – methodology for proper compensation • Potential for utility load to be less than energy purchased

Cost Recovery/Allocation: Capacity

Description in Order	Detailed in ICAP section
Calculation Methodology	Compensation divided into two parts: (1) best estimate of the capacity cost avoided based on each utility's methodology (ie strip, monthly and/or spot); (2) difference between compensation paid and best estimate of capacity cost avoided.
Reason for Compensation	If not for this generation at the time of the NYISO peak, the New York Control Area Peak Load Forecast would have been higher, more capacity would be purchased
Who Pays and Why	All Delivery customers whose ICAP tag calculation includes an Unaccounted for Energy (UFE) component will pay the best estimate of the capacity cost avoided. This benefits all LSEs and, theoretically, all customers. The difference between compensation paid and the best estimate of the capacity cost avoided will be recovered from customers within the same service class as the subscribers/solar customers.
Recovery Mechanism	Cost will need to be split into the two parts mentioned above with the avoided capacity cost spread over all customers in a mechanism similar to the dynamic load management mechanism, and the rest collected within the same service class as the subscriber/solar customers via a service class-specific surcharge.
Potential Issues	• Difficult to track and allocate • NYISO reevaluating load forecasting methodology – Potential to add these load modifiers back in to peak forecasts. • Prices unknown ahead of time • Differential between actual value and payment to DER

Cost Recovery/Allocation: Env. Credit – Default Option

Description in Order	Environmental compensation as the higher of the applicable Tier 1 REC price per kWh generated or the net SCC per kWh value. If the customer wants to keep the RECs, they do not get the E compensation.
Calculation Methodology	Calculation of cost to be divided into two parts. First part is the cost the utility would have otherwise paid for the REC. The second part is the cost of the REC to the developer minus the current market price of the REC.
Reason for Compensation	The utility's REC obligation is reduced by the RECs produced by the Value Stack qualifying generators
Who Pays and Why	All utility supply customers pay for the market price component . The over or under payment portion will be recovered from customers within the same service class as the subscribers/solar customers.
Recovery Mechanism	Costs will need to be split into the two parts mentioned above with the supply charges going to the utility supply customers. The rest will be collected within the same service class as the subscribers/solar customers via a service class-specific surcharge.
Potential Issues	Locking in price for 20 years may cause significant over or under payment since the REC market is new.

Cost Recovery/Allocation: Demand Reduction Value (DRV)

Description in Order	Approximate credit for project contribution of value to the overall distribution system
Calculation Methodology	Total dollars to collect is a straight calculation of predetermined DRV rate multiplied by the net injected coincident kW
Reason for Compensation	Potential project contribution of value to the overall distribution system
Who Pays and Why	All delivery customers since all receive a benefit. Costs will be broken down by service class based on the make up of the subscribers/solar customers receiving the DRV.
Recovery Mechanism	Collected via a service class-specific surcharge
Potential Issues	Anticipate updates with revisions to marginal cost studies

Cost Recovery/Allocation: Locational System Relief Value (LSRV)

Description in Order	Approximate credit for project contribution of value to the local distribution system
Calculation Methodology	Total dollars to collect is a straight calculation of predetermined LSRV rate multiplied by the net injected kW
Reason for Compensation	Potential project contribution of value to the local distribution system
Who Pays and Why	All delivery customers since all receive a benefit. Costs will be broken down by service class based on the make up of the subscribers/solar customers receiving the LSRV
Recovery Mechanism	Collected via a service class-specific surcharge
Potential Issues	LSRV area will face possible "competition" from other technologies and initiatives

Cost Recovery/Allocation: Market Transition Credit – (MTC)

Description in Order	Per kwh payment to projects receiving Value Stack compensation to bridge the gap between full NEM and the Value Stack
Calculation Methodology	Total dollars to collect is a straight calculation of predetermined MTC rate multiplied by the net injected kWh.
Reason for Compensation	To help lessen the step from full NEM to Value Stack. The MTC also includes any DRV.
Who Pays and Why	All delivery customers since all receive a benefit; costs will be broken down by service class based on the make up of the MTC subscribers/solar customers
Recovery Mechanism	Collected via a service class-specific surcharge
Potential Issues	

ICAP Issues

Determination of ICAP Credits

ICAP charges determined monthly (or seasonally) for mass market customers based on 3 inputs:

1. Capacity obligation (KW) of customer class
   - Coincident peak x applicable reserve requirement (including gross up for demand curve excess) for up to 3 separate capacity products (NYC, LHV, and ROS)
   - Requirements are "nested" such that a NYC purchases count towards G-J requirements and G-J purchases count towards NYCA / state-wide requirements
2. NYISO capacity costs ($/kW) from either seasonal strip auction for O&R and CECONY or monthly spot auctions for others +/- impact of applicable hedges
   - Auction results post just before applicable period
     - Strip Auctions for May – October 2017 results posted COB April 4
     - Spot Auction (which also determines demand curve volume) posts COB April 27 for May 2017
3. Projected customer-class sales (kWh)

Sample NYC ICAP Calculation

May 2016	NYC	G-J	ROS	Total
UCAP Requirement	72.83%	82.86%	106.21%	
Excess Demand Curve	7.57%	4.81%	5.81%	
Net UCAP Requirement	78.34%	86.85%	112.38%	
Effective Requirement	78.34%	8.50%	25.54%	
Spot Clearing Price	$12.41	$9.39	$5.27	
Weighted Price ($/kW)	$9.72	$0.80	$1.35	**$11.87**
With 6.3% Line Losses				**$12.61**
SC1 Coincident Peak	3,812,000	KW		**$48,084,792**
SC1 Summer Sales	1,310,166,667	KWH		**$0.037**

Location	Forecasted Peak Load MW	Requirement %	Derating Factor %	ICAP MW Requirement	UCAP MW Requirement	UCAP Effective %
NYC	11,793.5	80.5%	9.53%	9,493.8	8,589.0	72.83%
G-J Locality	16,309.4	90.0%	7.93%	14,678.5	13,514.5	82.86%
NYCA	33,358.8	117.5%	9.61%	39,196.6	35,429.8	106.21%

http://icap.nyiso.com/ucap/public/ldf_view_icap_calc_selection.do

Alternative 1 (default for intermittent)

- Default for intermittent units valuing all KWH of all exports using existing KWH ICAP rates
- Utilities would use existing process for setting retail rate and identify service class that best approximates solar production
- CECONY and O&R would continue to set rate twice annually based on Strip auction results while NYSEG, RGE, NIMO and CH would have monthly updates

Alternative 2 (permanent election)

- Concentrates ICAP value in 460 summer afternoon hours
- Initial filing May 15th with annual updates thereafter
  - Will not be applicable until summer 2018
- Will not have annual capacity costs at the start of the summer period so propose to use
  - 6 month summer (May – October) strip auction prices
  - midpoint of forward curves for following winter (November – April)
- Need to identify customer class load during 460 specified summer hours and amortize annual ICAP costs over those production hours
- Effectively front-loads the capacity revenue for any project electing Alternative 2

Alternative 3 (mandatory for dispatchable)

- Based on project-specific production coincident with NYISO peak
  - Actual exports at hour of system peak sets capacity (KW) value for the following capacity year (May – April)
  - Initial rating based on anticipated availability of technology times potential export (AC rating of project less customer load at peak)
- Peak production valued as "negative load" based on applicable reserve requirements (including gross up for demand curve excess) for up to 3 separate capacity products and applicable NYISO auction prices

MTC and Rules

Draft MTCs

- Staff provides draft MTCs for each utility in Appendix A of the Order
- Utility compliance calculations will reflect minor updates/adjustments to input values; utilities do not expect significant differences from values in Appendix A

MTC Calculation

$MTC_{Tranche1}$ = "Base Retail Rate" – "Value Stack"

$MTC_{Tranche2}$= (Base Retail Rate * 95%) – Value Stack

$MTC_{Tranche3}$= (Base Retail Rate * 90%) – Value Stack

"Base Retail Rate" =

+ Delivery Charge as of 3/9/17
+ MFC
+ SBC
+ Capacity portion of Supply Charge
+ "Energy +" (Supply Charge – Capacity)

2014-2016 36-month weighted average

"Value Stack" =

+ E value
+ Capacity portion of Supply Charge
+ DA LBMP (weighted average of all hours 2014-2016)

Three-year averages weighted by PV output

Rules for Applying the MTC & Tranches

- If there are X MW left in a tranche and the next project is X+ MW:
  - The project is compensated at the higher MTC of the earlier tranche
  - MW in excess of the limit on that tranche count toward the latter tranches
- Utilities send notice to the PSC immediately when tranche is filled; no additional projects may be added to that tranche
- 25% of interconnection fee deposit (or execution of interconnection contract if no deposit required) locks in tranche positioning

Rules for Applying MTC, DRV, & LSRV to CDG Projects

- Total compensation for the CDG project is calculated, then credits are allocated to subscribers based on individual allocations
- MTC is applied only to kWh output allocated to mass market (non-demand billed) customers
- Separate MTC values for residential and small commercial portions
- DRV is applied only to portion of the project allocated to demand-billed customers
- Where applicable, LSRV is applied to project as a whole

Allocation Basis & Updates

- CDG Host provides utility with Initial Allocation Request Form (% allocated to each customer subscriber) 60 days prior to in-service date
  - Utility calculates total compensation to project
- CDG Host provides utility with Subsequent Allocation Request Form 30 days before CDG Host's billing date to which modifications apply
  - Utility recalculates total compensation to project
- Subscribers receive monetary credits on a lag based on individual billing cycles

Example CDG Project Compensation Calculation

Example CDG Project Assumptions		
General Project Parameters	DER Project Type:	CDG
	Project Size:	2
	CDG Tranche Assignment:	2
	LSRV area?	Yes
	Metered Month:	6
	Project Monthly Net Output (kWh):	301,286
	Average Top 10 Hour Contribution ($/kW-year)	862
Subscriber Allocations	Demand-Billed Customer Allocation:	40%
	Mass-Market Customer Allocation:	60%
	Residential Allocation:	70%
	Small Commercial Allocation:	30%
Example Values (Based on Staff Workpaper Assumptions & Calculations for National Grid)	Tranche SC1 MTC Value:	$0.0246
	Tranche SC2ND MTC Value:	$0.0319
	Estimated Value Stack:	
	E (latest NYSERDA price):	$0.0242
	ICAP (based on SC1 charge):	$0.0125
	DA LBMP (3 year hourly average 2014-2016):	$0.0400
	Total Value Stack:	$0.0768
Example DRV & LSRV (NGrid)	System Average MCOS ($/kW-yr):	$66.48
	Example "Gross LSRV" Value ($/kW-year):	$99.72
	Example DRV Value ($/kW-year):	$62.47
	Example "Net LSRV" Value ($/kW-year):	$37.25

Example CDG Project Compensation Calculation Cont.

	Project Allocation			
	Mass Market		Demand Billed	
	60%		40%	
	Residential	Small Commercial		
	42%	18%		
Monthly kWh Output (kWh)	**301,286**			
Monthly Output Allocation (kWh)	126,540	54,232	120,515	
x Value Stack ($/kWh)	$0.0768	$0.0768	$0.0768	
Value Stack Compensation ($/month)	**$9,718.41**	**$4,165.03**	**$9,255.63**	
Monthly Output Allocation (kWh)	126,540	54,232	120,515	
x MTC ($/kWh)	$0.0246	$0.0319	N/A	
MTC Compensation ($/month)	**$3,110.69**	**$1,728.10**	N/A	
Project Size (MW)	**2**			
Project Size Allocation (MW)	1.2		0.8	
Top 10 Hour Contribution Allocation (kW-yr)	517		345	
x DRV ($/kW-yr)/12 months	N/A		$5.21	
DRV Compensation ($/month)	N/A		**$1,794.41**	
Project Size Allocation (MW)	1.2		0.8	
Top 10 Hour Contribution Allocation (kW-yr)	517		345	
x "Net LSRV" ($/kW-yr)/12 months	$3.10		$3.10	
"Net LSRV" Compensation ($/month)	**$1,604.94**		**$1,069.96**	
Total Project Compensation				
Value Stack Compensation ($/month)	$9,718.41	$4,165.03	$9,255.63	$23,139.06
MTC Compensation ($/month)	$3,110.69	$1,728.10	N/A	$4,838.79
DRV Compensation ($/month)	N/A		$1,794.41	$1,794.41
"Net LSRV" Compensation ($/month)	$1,604.94		$1,069.96	$2,674.90
Total Project Compensation				**$32,447.16**

Credited to customer subscribers based on individual allocation

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