Task 3.3
Draft & Final Report Summarizing Literature Review & ISO/RTO Tariff Analysis
Sovereign Energy Storage

Task Definition: Grant proposal narrative

- *Review ISOs/RTOs Tariffs outside of California to create a comparison of ancillary service values by resource mix*
    - *Focus on PJM, NYISO*
- *Review existing CA IOU and ISO tariff and program rules by value stream, to determine energy storage system specification required to qualify for each service*

Introduction:

Energy storage projects create revenue by providing products to retail customers and wholesale markets. Recent federal and state level policy has been created to break down barriers to participation of energy storage resources, connected both in front of and behind the meter, in wholesale markets. The market is in a transitory phase, and the full body of regulation required to account for all of the attributes of energy storage that can create value in wholesale markets will take years to be implemented at the state level.

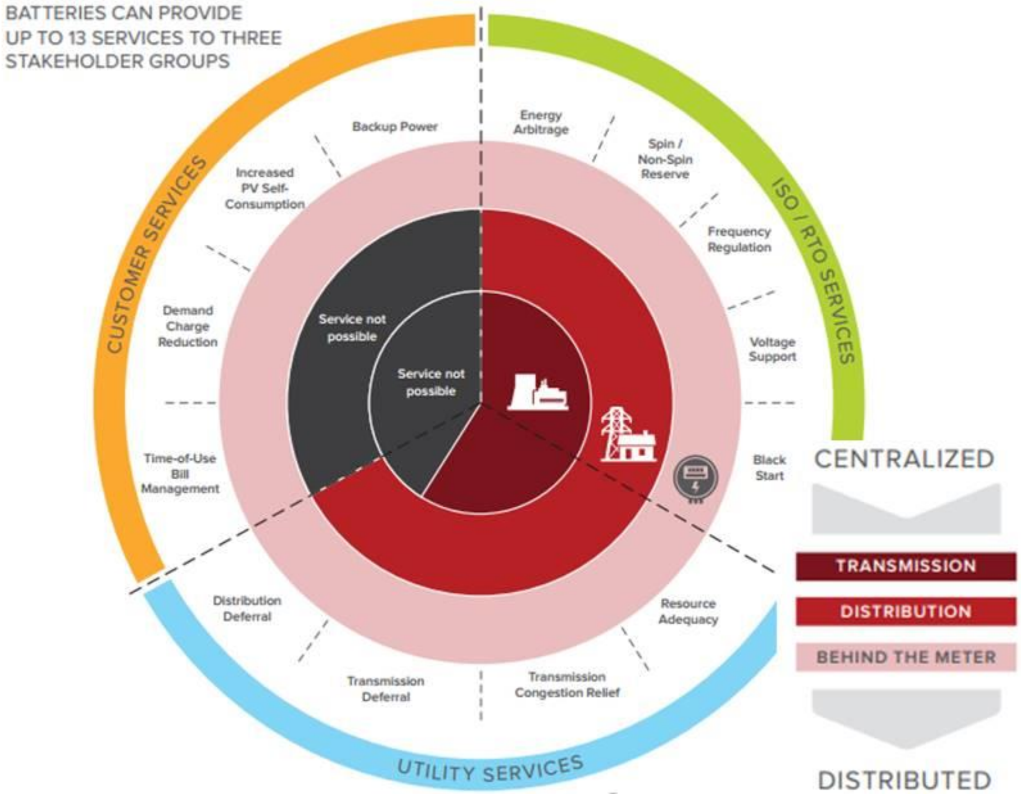
California has been at the forefront of implementing policy to animate the energy storage market, followed by PJM and New York. Each ISO is moving towards a similar goal with different approaches. This report will focus on the California market, as it is both the most advanced market and the most pertinent to PAEC, but will also examine PJM and NYISO as the processes in those ISOs have could establish the value of energy storage in ways which will also benefit California.

The principles of energy storage projects are the same in each of the ISOs in that they stack value created at the retail level and wholesale level to satisfy site host requirements and attract investors to projects. At the wholesale level, the projects work within the specific market frameworks to sell capacity, energy, and ancillary services. Capacity is sold through either long term bi-lateral agreements with utilities, or on a "merchant" basis, meaning they are cleared through auctions which result in short term contracts directly to the market. Energy and ancillary services are generally bid into the market on a merchant basis, in both a day ahead market in which the majority of supply is settled, and also a real-time market in which the final marginal units of energy and ancillary services are bought and sold.

Distributed energy storage balance these wholesale market obligations with retail services to end-customers. These retail services are typically bill savings generated by shifting energy usage from off-peak times to on-peak times, thereby lowering demand charge and energy costs for host customers.

The below graphic from the Rocky Mountain Institute (RMI) depicts the services a battery can provide to the electric system based on the point of interconnection. Batteries provide greater value the closer to load; distribution connected and behind the meter batteries should be able to provide the same wholesale services to the ISO as in front of the meter, transmission connected projects, once the regulatory and technical barriers are addressed.

RMI: Battery Storage Value Streams by Point of Interconnection



[1]

The above graphic from the Rocky Mountain Institute depicts the scope of services which energy storage can provide when interconnected at the transmission level, distribution level, and behind the meter. Generally speaking, transmission and distribution connected projects and considered 'centralized' and 'in front of the meter', whereas customer-connected projects are considered 'behind the meter'. It is important to note that the ability to provide wholesale market services from behind the meter (customer connected) projects is becoming possible quickly across the organized markets. This regulatory shift is being at the federal level through FERC, then at the regional level through the ISOs with the CAISO being the first major mover.

Additionally, regulation and technology is also enabling certain behind the meter applications such as backup power to be provided by distribution-connected storage projects using advances switching technology.

[1] Rocky Mountain Institute, "The Economics of Battery Energy Storage: How multi-use, customer-sited batteries deliver the most services and value to customers and the grid."

California

ISO Overview

California is the first market to wholeheartedly adopt and integrate distributed energy storage into the electricity system. This has been achieved through a combination of CPUC regulated incentives, high demand charges on commercial tariffs, and broad stakeholder group buy in to lay the regulatory foundation for a more flexible and clean electricity system. In 2001, the California Public Utility Commission (CPUC) introduced the Self-Generation Incentive Program (SGIP) as a peak load reduction measure to combat the California energy crisis (AB970). In 2013 the CPUC introduced AB-2514 (Storage Mandate), requiring the California Investor Owned Utilities (IOUs) to procure 1.35 GW of energy storage through rate-based purchases and contracts. These regulations catalyzed developers and utilities to take a hard look at storage economics and develop use cases and projects to benefit customers and provide adequate yield to investors.

As of 2015, under the SGIP program 544 projects have been completed for a total capacity of 252 MW. Energy storage developers such as Stem, Advanced Microgrid Systems (AMS), Tesla, and GreenCharge Networks have used the SGIP incentive and the additional California Supplier bonus to increase investor returns on projects which deliver demand charge management savings to host customers. In addition to applying for SGIP incentives, energy storage developers have been bidding into CA capacity programs using aggregations of behind the meter energy storage projects. In the 2013 Southern California Edison (SCE) Local Capacity Request for Offers (LCR RFO), Stem and AMS won 85 MW and 50 MW respectively. These commitments were for the delivery of local and system Resource Adequacy (RA) through demand response aggregations using batteries. These projects provide benefits to the system host through reductions in the demand charge portions of their bills or through rental payments delivered by the system owner. Future PAEC projects could realize revenues through similar RA programs with PG&E.

Given the large amount of developers looking to build battery projects in California, and the finite amount of SGIP funding dollars available, many developers are looking towards the solar ITC to improve battery project economics. In these PV + storage projects, the control system is set up to ensure that the battery charges at least 75% from energy generated by the solar system. The battery will receive a corresponding % of the investment tax credit for every % of the total kWh charged from solar.

> *Example:* if 92% of the energy used to charge from the battery comes from energy generated by the solar system, then the battery system is eligible to receive 92% of the 30% ITC benefit, or 27.6% of the capital cost recuperated through a tax benefit.

PAEC PV + storage projects could take advantage of the ITC and SGIP (as available). If projects take ITC, they will be limited in the amount of energy they can take from the grid to charge. This can be problematic in two scenarios:

1. If PV is unavailable to charge the battery, due to prolonged maintenance outage (such as inverter failure or long storm), the system will be unable to provide the Resource Adequacy energy when dispatched by the ISO;

2. The system will be limited in its ability to provide regulation down to the grid. The system will not be able to pull energy from the grid to charge without the subsequent reduction in ITC value. However, a PV + storage system could provide regulation down by reducing the scheduled delivery, using more of the delivered energy to charge the battery.

Example: In hour ending 17, the 100KW PV + 200KWh storage system is scheduled to delivery 100KWh of energy to the grid. The battery is at 50% SOC (100kWH). The ISO needs Regulation Down. The system dispatches 100% of its energy output to the battery (100kWH), resulting in 0KWh dispatched to the ISO. The ISO receives 100KW of Reg Down for that hour, without impacting the ITC eligibility of the PV + storage system.

Table: Wholesale Market Products

The following table describes products which are bought and sold in the CAISO wholesale market and the associated performance obligations of those products.

Grid Product	Definition	Obligations	Storage Participating
Resource Adequacy (Capacity, RA)	Resource Adequacy forces load serving entities to contract for a workable fleet of supply to serve an upcoming month or year of system operations. California IOUs and LSEs procure RA to serve their load. In the CAISO, RA is subject to a must-offer-obligation meaning that it must be scheduled or economically bid into the CAISO day-ahead and real time markets. There are 3 types of RA; Standard RA (serve CAISO summer peak), Local RA (ensure that peak within a load pocket can be met reliably), Flexible RA (ensure flexibility exists to meet the peak reliably given sharp ramps). There are 3 types of Flexible RA types, see tables below for qualification requirements and Must Offer Obligations.	4 hour minimum duration, which must be deliverable on 3 consecutive days. Ex: a 500 kW, 2 MWh battery system has 500 kW of RA value, and a 1 MW, 2 MWh battery also has 500 kW of RA, because the 500 kW power level can be delivered for 4 hours. Flexible RA resources must be economically bid into the CAISO market (cannot self-schedule). Flexible capacity is subject to a Must Offer Obligation (MOO) for each Category of Flexible RA – MOOs outlined in the table below. Flexible Resources obtain Effective Flexible Capacity (EFC), which can exceed Net Qualifying Capacity (NQC) of a resource. EFC = pMAX RA + pMin RA (NQC – pMinRA), where pMax RA = standard capacity value and pMin = minimum level a generator can achieve and still ramp to 0 over 1.5 hours. For example: in a 16 MW, 12 MWh system, pMax = 3 MW (3 MW x 4 hours = 12 MWh). pMin RA = 16 MW, because if the battery is fully discharged (-12MWh), it will charge 24 MWh of energy in 1.5 hours after which it will be at its pMax	Yes

Day Ahead Market (DAM)	Energy market that schedules supply in 24x1 hour blocks, while also procuring Ancillary Services capacity. Prices energy at $/MWh at each Locational-Marginal Price (LMP) node in the CAISO system. The LMP is calculated as the marginal price of energy adjusted for losses and congestion.	A resource must be registered in the CAISO Master File but does not need to qualify for Resource Adequacy	Yes
Real Time Market (RTM)	A 15-Minute and 5-Minute market that matches supply and demand and may procure incremental ancillary services.	A resource must be registered in the CAISO Master File but does not need to qualify for Resource Adequacy	Yes
Flexible Ramping Product (FRP)	Procured in the 15-Minute RTM as capacity to meet expected or potential ramp needs in subsequent intervals. Prices clear as a $/MW capacity price + an energy settlement.	The resource must qualify for Flexible Capacity RA	Yes
Spinning Reserve	A capacity product used in a contingency situation that must be available and synchronized to grid frequency within 10 minutes of being called. Prices clear as a $/MW capacity price + an energy settlement.	A resource must be registered in the CAISO Master File but does not need to qualify for Resource Adequacy	Yes
Non-Spinning Reserve	A capacity product used in a contingency situation that must be available within 30 minutes of being called. Prices clear as a $/MW capacity price + an energy settlement.	A resource must be registered in the CAISO Master File but does not need to qualify for Resource Adequacy	Yes
Regulation Up and Down	A short duration capacity product under CAISO control through an Automatic Generator Control (AGC) signal. The AGC will dispatch for Reg Up/Down based on frequency deviations every 4 seconds. Prices clear in a $/MW capacity payment + Mileage payment + energy payment.	A resource must be registered in the CAISO Master File but does not need to qualify for Resource Adequacy	Yes
Regulation Energy Management (REM)	Within the CAISO there is a subset of Reg Up/Down called Regulation Energy Management (REM)	Storage resources participating in the CAISO market can obtain Non-Generating Resource (NGR) capability and be registered as such in the CAISO master file, enabling participation in	Yes

		REM market. Resource must bid from 5:00am – 10:00pm into Reg Up and Reg Down markets, be available 7 days per week for unlimited starts. System must have a minimum of 15 minutes energy storage duration for charging and discharging	

Flexible Resource Adequacy Categories:

Category	Requirements	Examples
Base ramping flexibility	Must provide 6 hours of energy at EFC value Minimum 2 startups per day Available 7 days per week	• Gas-fired resources • Hydro resources • Wind resources • Long duration storage
Peak ramping flexibility	Must be able to provide 3 hours at effective flexible capacity value Minimum 1 startup per day Available 7 days per week	• Use-limited gas-fired • Solar resources • Gas peakers
Super-peak ramping flexibility	Must be able to provide 3 hours of energy at EFC value Minimum 5 dispatches per month Available on week-day non-holidays Or Regulation Energy Management (REM) resources bid from 5am to 10pm	• Demand Response • Short Duration Storage Or • Regulation Energy Management (REM) resources

Energy storage system costs increase on a linear basis with their duration. For example, if system costs are $500/kWh, a 10 MW, 60 MWh (6 hour) system will cost $30MM, and a 10 MW, 30 MWh (3 hour) system will cost $15MM. Because of this cost duration-based cost structure, it is much more expensive to install longer duration systems, and the system owner, resulting in a higher price for providing a service from a longer duration system. It will be much more expensive for an energy storage project to sell base ramping flexible capacity, which requires 6 hours, than it will be for a 3 hour project to sell Peak Ramping Flexible Capacity or Super Peak Ramping Flexible Capacity.

Flexible Resource Adequacy Must Offer Obligations:

	Category 1	Category 2	Category 3
Must-offer obligation	17 Hours	5 Hours	5 Hours
	5 AM- 10 PM Daily For the whole year	12 PM to 5 PM for May – September	12 PM to 5 PM for May – September
	5 AM- 10 PM Daily For the whole year	3 PM- 8 PM for January- April and October-December	3 PM- 8 PM for January- April and October-December
	Daily	Daily	Non-holiday weekdays
Energy limitation	At least 6 Hours	At least 3 Hours	At least 3 Hours
Starts	The minimum of two starts per day or the number of starts feasible with minimum up and down time	At least one start per day	Minimum 5 starts a month
Percentage of LSE portfolio of flexible resources	At least 64 % for May – September	Up to 36% for categories 2 and 3 combined	Up to 5%
	At least 50 % for January- April and October-December	Up to 50% for categories 2 and 3 combined	Up to 5%

[2]

Table: AS Prices (historical average)

Product	2014 Price	2015 Price	2016 Price
Resource Adequacy (Capacity, RA)	$3.32/kW-Mo (104,947MW)	$2.90/kW-Mo (91,788MW)	$3.29/kW-Mo (54,289MW)
Day Ahead Market (DAM)	$36 – $67/MWh	$26 – $50/MWh	$20 – $37/MWh
Real Time Market (RTM)	-	$26 – $42/MWh	$22 – $38/MWh
Spinning Reserve	$0.10 – $11.00/MWh	$0.10 - $9.00/MWh	$0.10 – $10.80/MWh
Non-Spinning Reserve	$0.10 – $0.50/MWh	$0.10 – $1.40/MWh	$0.10 – $1.20/MWh
Regulation Up	$1.20 – $14.00/MWh	$2.00 – $13.80/MWh	$8.50 – $17.50/MWh
Regulation Down	$2.00 – $5.80/MWh	$1.90 – $4.00/MWh	$4.00 – $10.00/MWh

Although the cost curve of energy storage equipment and installation (hard and soft costs) are falling at a rate of 10% - 20% annually, any single wholesale market revenue stream listed above is not sufficient on its own to create acceptable project returns for an investor. Project developers perform a detailed analysis of participation rules for each wholesale product to determine which, if any products may be delivered simultaneously, and how a battery charge/discharge profile can be structured on a 24 hour basis to enable the project to earn revenue at all hours of a day.

In addition to the above wholesale products, energy storage projects also perform demand charge management at customer sites. Demand charge management revenue is created at the peak demand charge level of each tariff. For example, the PG&E E-19 commercial tariff is currently $23/kW-Mo on peak, so every kW of demand reduced at a customer site will contribute $23/Month to be shared in some fashion between the system owner and site host.

To date, the vast majority of distributed energy storage participating in the capacity and energy market has been through Load Modifying Demand Response. Under Load Modifying Demand Response, DR participation is monetized by California LSEs by subtracting the capacity of the demand resources from

[2] Flexible Resource Adequacy Criteria and Must Offer Obligation – Phase 2

their RA procurement obligations. For example, when SCE procured 85 MW from Stem in the 2013 LCR RFO, Stem's aggregated portfolio must conform to Standard RA obligations, and in turn SCE will register the contract as an 85 MW reduction of its requirement to procure RA. In contrast, the ISO is moving towards a more integrated approach to DER participation called Supply-Side DR. Under Supply-Side DR, the DER aggregation will be dispatched directly into the market by a scheduling Coordinator and be responsible for fulfilling all obligations associated with each product it delivers. Below is a summary of some of the demand response programs offered by DR aggregators and utilities across California

Table: Demand Response Programs[3]

Program	Description
Base Interruptible Program (BIP)	An advanced demand-response program aimed at very large commercial and industrial users, BIP provides customers substantial monthly bill credits but has short notice given before event periods. Non-performance in these events can result in large penalty charges for usage. • Participants must be on a demand-metered time-of-use rate schedule, have an average monthly demand of >100kW, and be able to curtail >15% of their average monthly load or >100kW, whichever is greater • An interval meter that can be read remotely is required for enrollment in BIP; as is internet access and a working email address • 30 minutes' advance notice is given prior to a curtailment event. Event triggers include: a CAISO Stage 2 emergency, a publicly issued warning notice of an imminent CAISO Stage 1 emergency, forecasted CAISO system conditions, or local system needs as determined by PG&E • Curtailment events are limited to four hours per event, one event per day, 10 events per month, and 120 total hours per year • Your monthly bill credit is applied even on months where no curtailment event is called, and ranges from $8.00/kW to $9.00/kW depending on your Potential Load Reduction (PLR) • In the summer, your PLR is the difference between your average on-peak demand and your firm service level (FSL); in the winter, your PLR is the difference between your average partial-peak demand and your FSL • A charge of $6/kWh will be assessed when you fail to reduce your load to, or below, your FSL during the entire duration of a curtailment request • Once enrolled, you may adjust your FSL or discontinue participation once each year during the month of November
Demand Response Auction Mechanism	The DRAM is a pay-as-bid auction of monthly system Resource Adequacy (RA) associated with a demand response product located in the IOU's service area and where sellers offer directly into the CAISO day-ahead energy market. The IOU only acquires the third party Demand Response Aggregators' (sellers') RA, and has no claim on revenues the winning bidders may receive from the CAISO energy market. Each bidder acts as its own scheduling coordinator. The IOU reimburses certain scheduling coordinator related costs for winning bidders.
Demand Bidding Program	This program allows you to submit load reduction bids on an hourly basis for any curtailment event and carries no financial penalty for failing to deliver as bid for any or all hours of an event.

[3] Marin Clean Energy Demand Response Program Offer

	• DBP requires that your facility be on an electric demand time-of-use rate schedule, have been billed a maximum demand of 50 kW or greater during any one of the past 12 months, and be able to reduce demand by at least 10 kW for two consecutive hours or more during an event • Participants must have a SmartMeter or interval meter that can be read remotely and is capable of recording usage in 15-minute or shorter intervals • An internet connection and email address, along with cellular phone service capable of receiving text messages, is required in order to receive program notifications; internet access is also necessary to submit DBP bids • Day-ahead notice is given, by 12 noon, prior to a curtailment event in response to the following triggers: a CAISO alert (any stage), a CAISO load forecast exceeding 43,000 MW, a temperature forecast that exceeds the temperature threshold for the customer's assigned LoadZone, or inadequate system capacity or generation resources as determined by PG&E -- PG&E also reserves the right not to call a DBP event when these triggers occur • Incentive rate is $0.50/kW per hour and payment credits are applied to your bill within three months after the event • Incentive payments for load reductions begin upon achieving 50% of bid amount and are capped at 150% for each hour of the event
Optional Binding Mandatory Curtailment Plan	In return for being exempted from rotating outages, OBMC participants submit a plan each year that is designed to achieve a 15% load reduction on the entire electric circuit load of their facility. • If you are the only customer on your circuit, standard interval metering may be sufficient for you to participate in the program, for multi-customer circuits, substation-level metering is required -- program participants will pay the cost of any additional required metering equipment • PG&E will facilitate communications between customers on a shared electric circuit for the purposes of participating in this program. • An email address and text messaging device is required for receiving OBMC notices of event times and the load reduction target (5% – 15%) • An event may be called with 15 minutes' notification on any day (holidays and weekends included) without limitations to frequency of duration • As an incentive, your participation in OBMC exempts you from rotating outages • It is required that you submit a load-reduction plan each year and are capable of reducing your circuit's demand 15% below the baseline demand on your circuit • Baseline is calculated using your circuit's electric load data from the 10 days prior to an event (excluding weekends, holidays and event days); you also have an once-annual option to elect a "dayof adjustment" to the baseline that incorporates your energy usage on the morning of the event • There is a $6/kWh penalty for failing to achieve your target reduction during an event • You will be terminated from the plan for failure to reduce load a second time during a one-year period, and participation is denied for a period of 5 years after termination
Aggregator Managed Portfolio	AMP is managed by one of 5 aggregators – each of whom is responsible for designing their individual program, enrolling and supporting customers, and performing event notifications. Program details, including incentives vary depending on the aggregator, but the following should be applicable to all participants in AMP: • Participants must be on a commercial, industrial, or agricultural rate schedule; customers who are on full standby are not eligible for AMP • You must have an interval meter or SmartMeter

	• AMP curtailment events may be called from May 1st through October 31st, may last from 4 to 6 hours, but will not exceed 80 hours in a year; up to two test events lasting at least 2 hours may also be called • Events may be called on a day-of or day-ahead basis depending on the program offerings of individual aggregators, and the curtailment window is from 11:00 AM – 7:00 PM on weekdays (excluding holidays)
Capacity Bidding Program	Like AMP, Capacity Bidding Program is an aggregator-managed program that offers day-ahead or day-of notification of events and whose program features, including incentives, are determined by each participating aggregator. The following general guidelines are present across all aggregation programs: • To be eligible for CBP, you must be on a commercial, industrial, or agricultural rate schedule, and not be on full standby • You must have an interval meter or SmartMeter • Events may be called on a day-of or day-ahead basis in accordance with the notification options provided by individual aggregators • The curtailment season runs from May 1st through October 31st, and events must take place on nonholiday weekdays and are limited to one event per day between the hours of 11:00 AM and 7:00 PM, and a cap the frequency of events at 30 event hours per operating month • Up to two test events may be called per calendar year
Peak Day Pricing	Peak Day Pricing offers business customers the chance to receive discounts on electricity rates during the summer months (May through October) for some-or-all of their load. During a PDP Event, failure to reduce usage below the set PDP threshold results in significant penalty rates. PDP customers are notified of events on a day-ahead basis; these events are limited to between 9 and 15 per year and are scheduled between 2 and 6 PM.
Scheduled Load Reduction Program	SLRP allows qualified participants to pre-schedule between one and three 4-hour curtailment events, preselect their committed load reduction and earn $0.10/kWh per month (June through September) for their actual energy reductions. Committed load reductions are determined against a baseline determined by your facility's previous 10 weekdays' load history, and must be at least 15% of average monthly demand or 100 kW, whichever is greater.

Energy Storage Project Types and Business Models

In California, energy storage project economics are based on controlling the battery system to lower the peak at a customer facility, act as a capacity resource for utility or wholesale participation, receive available incentives through the SGIP and ITC, and if possible access multiple revenue streams with the same device. The following configurations have been utilized to achieve these revenue streams and construct economically viable projects:

1. Using a battery for peak demand management:
    - Peak demand management (or Demand Charge Management, DCM) is performed by lowering the metered demand for the highest 15-minute interval each month. As the battery operated to lower demand charges daily, revenue is created in terms of bill savings as a customer's demand is lowered.
    - Example: if a customer has a peak of 1,000 kW, and a 200 kW battery successfully cuts the peak every month to 800 kW, the revenue created from demand charge management is 200 kW * the demand tariff (in PG&E E-19 territory the demand charge

is $20/kW, so total revenue created is 200 kW * $20/kW = $4,000/Month).

2. PV + Storage to receive the Investment Tax Credit:
    - A storage system is eligible to receive the ITC if the system owner can prove that greater than 75% of the energy discharged by the battery was generated by electricity generated from the solar system. If 75% of the electricity discharged by the battery was generated from the solar system the storage system is eligible to receive a tax incentive equivalent to 75% of the solar ITC, which is currently 30% of the eligible capital cost (75% * 30% = 22.5%). If 100% of the electricity discharged by the battery was generated by the solar system then the storage system is eligible for a tax incentive equivalent to the full ITC.
    - When the system is in operation, the battery will draw charging energy from the PV system during morning peak production hours when the energy generated would otherwise be injected to the grid. The load will then draw energy stored from the battery instead of grid energy during evening peak times when the load is highest and the PV system is no longer producing energy. During hours when cloud cover is over the PV system and the load would spike and potentially trigger a monthly demand charge, the battery system will be reading the load to mitigate the occurrence of that event.

3. PV + Storage and the SGIP incentive
    - A storage system can receive both the ITC and an SGIP incentive, however under SGIP rules (see 2016 handbook 3.3.4) the customer (i.e. system owner) must pay for a minimum of 40% of the eligible project costs. Under this scenario, the ITC benefit would only be accretive to the project if the SGIP incentive level was below 60% of the project cost.
    - Example: (see 2016 Incentive Levels) the 2016 Advanced Energy Storage incentive is $1.31/w. If the storage system eligible cost is $3/w, then $1.31/w only covers 43% of project costs. To achieve the full 60% benefit available between ITC and SGIP, the additional 17% of project costs, or $0.49/w can be attained through filing for the ITC.
        i. In practice, the project will receive the full ITC benefit of 30% (30% * $3/W = $0.9/w), and the SGIP rebate will be limited to ($1.80 - $0.90) = $0.90.

4. PV + Storage + DR
    - PV + Storage projects can receive the ITC and participate in certain DR markets. It is not possible for a specific asset to receive funding from multiple CPUC regulated programs, so rules differ across DR programs. In their recent energy storage DR RFOs, the CA IOUs have made it clear that equipment that receives incentives through the SGIP program is not eligible to participate in a bi-lateral utility DR program. To date, wholesale participation in the DRAM program in addition to participation in the SGIP program has been allowed.
    - As a general rule the utilities try to limit participation in multiple regulated programs, but the CPUC recognizes that since the battery can perform multiple functions in the market, dis-incentivizing that performance can have an adverse effect on rate payers. For example, the SGIP program is essentially a peak-demand reduction program, so if

there is a separate regulated program that would incent participation in ancillary service or energy markets, in principle that should be allowed. The rules are not clear as of yet, and developers should consult the local utility and CPUC staff before constructing projects with multiple regulated incentives anticipated.

5. Storage only + SGIP
    - Storage-only projects can perform peak demand management on site and can receive the SGIP incentive for up to 60% of eligible project costs, capped at an annual rate determined by the CPUC. California suppliers are eligible to receive an additional 20% of the incentive level, however they are still subject to the 60% cost cap. Systems under 30 kW in nameplate capacity earn the full incentive upon commissioning, systems over 30 kW earn 50% of the incentives upon commissioning, and the remaining 50% over the next 5 years through a Performance Based Incentive (PBI) that is paid per kWh as metered from the battery. Battery systems must perform 260 cycles per year to receive the full PBI.

2016 Incentive Rates by Eligible Technologies

Technology Type	Incentive ($/W)
Renewable and Waste Energy Recovery	
Wind Turbine	$1.02
Waste Heat to Power	$1.02
Pressure Reduction Turbine	$1.02
Non-Renewable Conventional CHP	
Internal Combustion Engine - CHP	$0.42
Micro-turbine – CHP	$0.42
Gas Turbine – CHP	$0.42
Emerging Technologies	
Advanced Energy Storage	$1.31
Biogas Adder	$1.31
Fuel Cell – CHP or Electric Only	$1.49

[4]

6. Storage only + DR + DCM
    - Storage only projects can perform both peak demand management on-site and perform Demand Response in bi-lateral utility programs. In order to successfully deliver DR, the battery must discharge into the load, lowering the metered load for a specific interval period. In California the demand response is measured according to a 10 day average baseline methodology. Under this methodology, each hour during the past 10 similar days prior to an event is averaged to establish an hourly baseline for those 10 days. The capacity of DR delivery is counted against this baseline.
    - Energy storage projects can perform both DCM and DR, but the software must take care to monitor the state of charge and baseline of the load, to ensure that when DR is called upon the site can achieve the full capacity possible.
    - When battery systems are sized to perform the DR + DCM stacked use case, they must

[4] 2016 SGIP Handbook

fully value both the pricing of each application, and the associated performance obligations and liquidated damages for non-performance. This is because the site level software will make a decision to perform the highest value operation in any event situation. Performance penalties must be fully valued in the initial site sizing analysis to inform proper sizing to loads.

California Policy Summary

Looking forward, the CPUC, CEC, and CAISO envision a bi-directional grid where energy storage is providing bill reducing services to the end customer, capacity to the utility, and grid services to the CAISO off of the same assets. In order to make this vision of the future a reality there are processes underway to modify the classification of distributed storage assets under the CAISO tariff to allow for the export of energy under certain scenarios and the buying and selling of energy products across stakeholders. Key proceedings and recommended policy structures are discussed below:

<table>
<tr><th><u>Proceeding</u></th><th><u>Summary</u></th></tr>
<tr><td>CPUC: Rulemaking on Energy Storage Procurement R.10-12-007 (AB-2514)</td><td>Directed investor-owned utilities to procure at least 1,325 MW of energy storage in four biennial solicitations through 2020. Other load-serving entities have targets based on 1% of peak load by 2020. This rulemaking provides a basis for cost/benefit analysis of storage in several use cases, illustrating how storage might provide services to the utility grid in transmission, distribution and customer applications. AB-2514 allows IOUs to use storage procured through other solicitations and programs to count toward meeting targets.

Proposed Energy Storage Procurement Targets (in MW)[22]
<table>
<tr><th>Storage Grid Domain
Point of Interconnection</th><th>2014</th><th>2016</th><th>2018</th><th>2020</th><th>Total</th></tr>
<tr><td>Southern California Edison</td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>Transmission</td><td>50</td><td>65</td><td>85</td><td>110</td><td>310</td></tr>
<tr><td>Distribution</td><td>30</td><td>40</td><td>50</td><td>65</td><td>185</td></tr>
<tr><td>Customer</td><td>10</td><td>15</td><td>25</td><td>35</td><td>85</td></tr>
<tr><td>Subtotal SCE</td><td>90</td><td>120</td><td>160</td><td>210</td><td>580</td></tr>
<tr><td>Pacific Gas and Electric</td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>Transmission</td><td>50</td><td>65</td><td>85</td><td>110</td><td>310</td></tr>
<tr><td>Distribution</td><td>30</td><td>40</td><td>50</td><td>65</td><td>185</td></tr>
<tr><td>Customer</td><td>10</td><td>15</td><td>25</td><td>35</td><td>85</td></tr>
<tr><td>Subtotal PG&E</td><td>90</td><td>120</td><td>160</td><td>210</td><td>580</td></tr>
<tr><td>San Diego Gas & Electric</td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>Transmission</td><td>10</td><td>15</td><td>22</td><td>33</td><td>80</td></tr>
<tr><td>Distribution</td><td>7</td><td>10</td><td>15</td><td>23</td><td>55</td></tr>
<tr><td>Customer</td><td>3</td><td>5</td><td>8</td><td>14</td><td>30</td></tr>
<tr><td>Subtotal SDG&E</td><td>20</td><td>30</td><td>45</td><td>70</td><td>165</td></tr>
<tr><td>Total - all 3 utilities</td><td>200</td><td>270</td><td>365</td><td>490</td><td>1,325</td></tr>
</table>
</td></tr>
<tr><td>CPUC: Applications for Energy Storage Procurement Plans, A.14-02-006, et al.</td><td>In response to the Energy storage procurement rulemaking, the three IOUs filed plans for the initial solicitation issued December 2014. The plans include a Common Evaluation Protocol (CEP) to provide a public benchmark for evaluating projects selected by the IOUs in their solicitations.</td></tr>
<tr><td>CPUC: Rule 21 Interconnection, R.</td><td>The goal of the Rule 21 Interconnection Proceeding is to promote timely, non-discriminatory, cost effective, transparent interconnection of new facilities to</td></tr>
</table>

11-09-011	the grid, including energy storage. The CPUC determined in R.10-12-007 that interconnection policies are among the major barriers toward the deployment of storage. In July 2014, Energy Division staff issued a document: Issues, Priorities and Recommendations for the Interconnection of Energy Storage.
CPUC: Distributed Energy Resource Planning Rulemaking R.14-08-013	Also in response to AB 327 (PUC section 769), the Commission launched a rulemaking to consider policies to enable distribution energy resource (DER) planning by the IOUs. The law specifies these DERs: distributed renewable generation, energy storage, electric vehicles, energy efficiency and demand response, and directs that Distribution Resource Plans (DRPs) must be filed by July 1, 2015.
CPUC: Resource Adequacy R. 14-10-010	The Resource Adequacy program has two goals. First, it provides sufficient resources to the California Independent System Operator to ensure the safe and reliable operation of the grid in real time. Second, it is designed to provide appropriate incentives for the siting and construction of new resources needed for reliability in the future. Periodic Rulemakings address refinements of RA requirements necessary to meet expected system operational needs and establish capacity valuations for resources that can meet those needs.
CAISO: Non-generator resources in Ancillary Services	This stakeholder initiative is for compliance with FERC Order Nos. 719 and 890. FERC Order No. 719, Wholesale Competition in Regions with Organized Electric Markets, directs Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs) to allow demand response resources to participate in Ancillary Service (AS) Markets assuming the demand response resources are technically capable of providing the ancillary service within response times and other reasonable requirements adopted by the RTO or ISO. FERC Order No. 890, Preventing Undue Discrimination and Preference in Transmission Service, requires that non-generation resources such as demand response must be evaluated on a comparable basis to services provided by generation resources in meeting mandatory reliability standards, providing ancillary services and planning the expansion of the transmission grid. Status: The Board of Governors approved the proposal in March 2010.
CAISO: Flexible Ramping Product	In August 2011, the California ISO Board of Governors approved the flexible ramping constraint interim compensation methodology. At that time the ISO committed to begin a stakeholder initiative to evaluate the creation of a flexible ramping product that will allow the ISO to procure sufficient ramping capability via economic bids. Through this initiative, the ISO will evaluate allocating costs to generation and load in accordance with cost causation principles.
CAISO: Flexible resource adequacy criteria and must offer obligations	The ISO is working with the CPUC and local regulatory authorities to ensure flexible capacity resources are available to reliably operate the grid while fulfilling state energy mandates. The work includes developing the tariff changes necessary for the ISO to accommodate the resource adequacy flexible capacity requirements adopted by regulators. This includes establishing availability, must offer obligations and default provisions for entities that fail

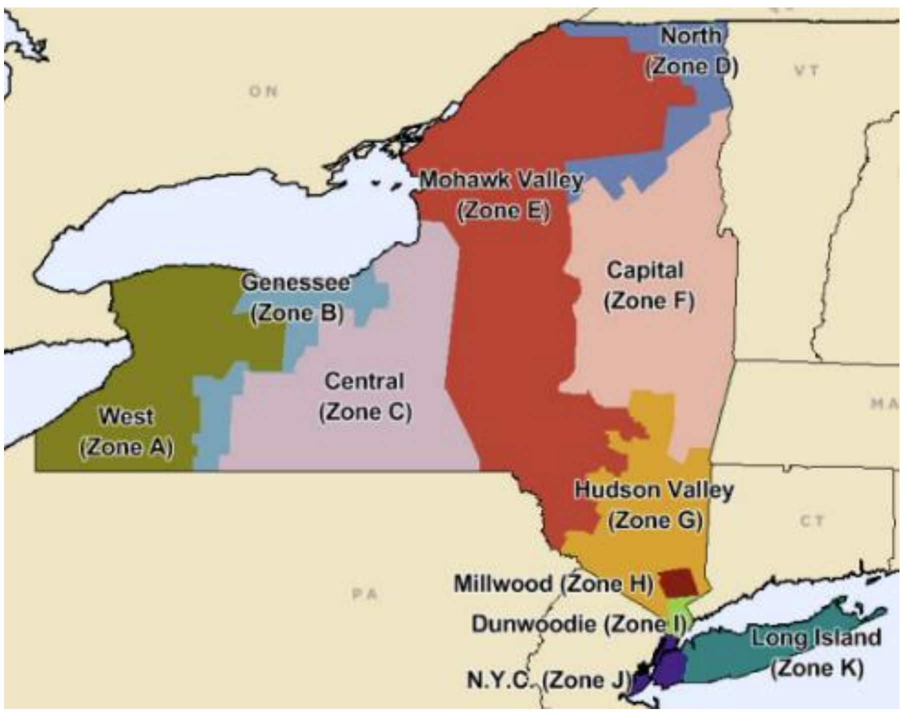
	to procure their flexible capacity allocations. Status: FERC approval: pending, Tariff amendment filing: August 1, 2014, Board of Governors approval: March 20, 2014.

New York

ISO Overview

The New York market for energy storage is in a more nascent stage than California. Currently, developers can make distributed energy storage projects attractive to hosts and investors by stacking DCM, ConEd DR, and NYISO DR (iCap SCR program). However, the New York Independent System Operator (NYISO) and New York Public Service Commission (PSC) are in the early stages of planning a fundamental market transformation that will enable Distributed Energy Resources (DER) to access revenue streams in the wholesale market and a new distribution level market. In general, this new paradigm is termed the DER initiative. Currently, because capacity has such a high value in zones G, J, and K (Westchester County, Lower Hudson River, New York City, and Long Island), projects have satisfactory investor returns under the current framework. In the future, as DER is implemented, projects will be able to achieve higher value in these zones and there will be more value on the table in other zones.

NYISO Load Zones[5]

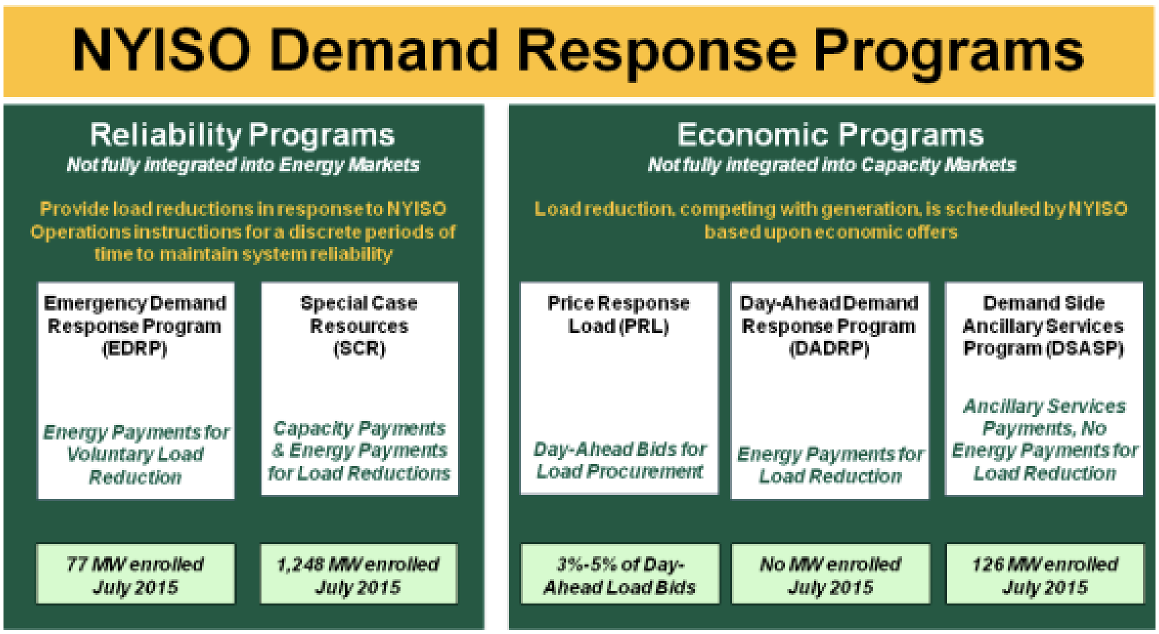


The NYISO generally considers DER to be behind-the-meter resources, although small aggregations of remote net metered resources, such as community solar, will also be considered DER. Some DER may be net generators and others net loads. For resources that are net generators, the scope of participation in these programs would be limited to resources and aggregations that do not meet the requirements of NYISO's existing Behind-the-Meter Net Generation program.

5 NYISO Load Zones

Currently, DER can support NYISO markets, planning, and operations in a limited manner – primarily through the NYISO's reliability-based DR programs where DER can be called upon to reduce demand to maintain system reliability. Enhanced integration of DER into New York's wholesale electricity markets will more efficiently support operations and planning. This integration will also provide dynamic price signals to inform DER investment and operational decisions.

NYISO Demand Response Program Summary[6]



Currently storage can participate in one reliability program and one economic program. The most lucrative reliability program for dispatchable resources is the ICAP SCR program, therefore all distributed resources which can meet the performance obligations participate in that program to receive capacity and energy payments. The ICAP SCR program is fully integrated into the wholesale market. During hours when resources are not committed to the ICAP SCR program, resources will participate in the Demand Side Ancillary Services Program (DSASP). The DSASP program currently provides marginal revenue to projects, so battery developers must take care to analyze whether the wear and tear on the battery is limited enough for the revenue from DSASP to be accretive to project economics.

[6] Distributed Energy Resources Roadmap for New York's Wholesale Electricity Markets

NYISO DR Programs

Program	Description	Volume
Day-Ahead Demand Response Program (DADRP)	Users participate in market by identifying load reduction in response to day-ahead market signals. Users identify a price-point at which they will reduce electricity use or self-supply using DER. Users receive energy payments based on their ability to deliver	0 MW
Demand Side Ancillary Services Program (DSASP)	End-users receive payments based on their ability to provide Ancillary Services (Operating Reserves or Regulation)	126 MW
Day-Ahead Price-Capped Load Bidding, or Price Responsive Load (PRL)	LSE submits price-sensitive day-ahead load bids for the amount of load it procures. Only available to LSEs?	
Emergency Demand Response Program (EDRP)	End-users perform on a voluntary basis; when the NYISO declares its need for these resources it requests EDRP participants to initiate curtailment strategies. The NYISO settles participation with energy payments based on performance.	77 MW
Special Case Resource (SCR)	End-users earn capacity payments by enrolling in in program and being available with a 21-hour advisory window and 2-hour activation notice	1,248 MW

The NYISO recognizes that, unlike traditional generators, DER will likely participate in its markets on an aggregated basis. The NYISO's current infrastructure for meter data supports Point Identifier1 (PTID) level data of large supply resources, primarily collected through telemetry for real-time operations and monitoring functions, and after-the-fact uploads to support settlement. The integration of DER into Energy and Ancillary Service markets is expected to follow the same model. DER will be required to provide PTID-level real-time supervisory control and data acquisition (SCADA) quality or better telemetry data for operations and monitoring functions, and after-the-fact revenue quality meter data from individual resources for measurement and verification, and settlements. Some of these measurement and verification services may be performed by the DSP. As part of this roadmap the NYISO intends to explore the use of real time telemetered data from a sample set of resources participating as a DER aggregation.

The NYISO envisions the future state of DR programs to look like that of the Figure 1 below. Some of the existing programs would remain intact while others would be replaced. As shown below, the current SCR program, Emergency Demand Response Program (EDRP) and Price Capped Load Bidding would remain. The current Day-Ahead Demand Response Program (DADRP) and Demand Side Ancillary Services Program (DSASP) programs would be replaced with the DER program.

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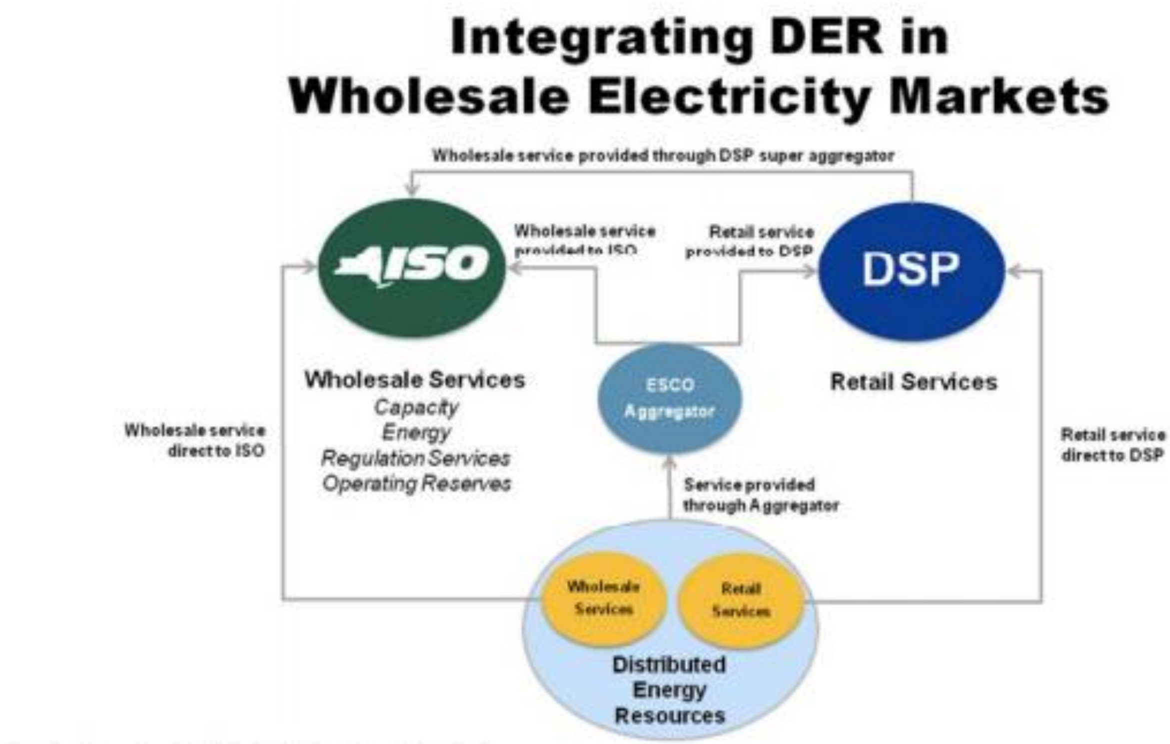

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[7] Distributed Energy Resources Roadmap for New York's Wholesale Electricity Markets
[8] Distributed Energy Resources Roadmap for New York's Wholesale Electricity Markets

The NYISO DER program envisions 5 types of resources that can participate in NYISO's Energy, Capacity, and Ancillary Services markets:

1	**Load-Only Resources**	Modulating energy uses strictly through load curtailment
2	**Load with Generation**	Dispatching behind the meter generation resources and/or load curtailment to modulate their demand from the grid
3	**Load with Storage**	Calling behind-the-meter storage resources and/or load curtailment to modulate their demand from the grid
4	**Load with Generation and Storage**	Calling upon a combination of behind the meter generation, storage, and load to adjust their demand
5	**Controllable generation with remote load obligations**	Community solar, retailer

In the future, the SCR will stay in existence to provide system flexibility. The EDRP will continue to be a reliability program with energy payments. DERs will still be able to perform as a load modifying DR resource to reduce the LSE's capacity obligations. DERs will also be able to perform in the day-ahead market through price responsive load bidding and real-time wholesale market price signals. Effectively, this DER program will treat distributed resources comparably with gas turbine generators, fully integrating them into the Energy and Ancillary Services markets while awarding capacity payments reflective of performance capabilities. The rules around DER performance are still forming, but the general framework is expected to correspond to the below:

DER with Capacity Obligation	• 3 types of capacity offers will be made based on the resource type: 24 hour (full day), Daytime, Peak • 24 hour resources will receive the highest value, and the other capacity-types will receive payments in a pro-rated methodology based on the total value contributed to the system • Each resource will have a must-offer obligation into the day-ahead market • If the resource is not dispatched into the day-ahead market it will be obligated to be available in the real-time market, but the bidding structure is not yet defined for DERs • If a DER does not participate as it has been committed to, it will be required to submit a de-rate report into NYISO's outage portal • A DER resource will be able to aggregate multiple technologies to achieve its performance obligations
DER without Capacity Obligation	• DER that are unable to fulfill NYISO Capacity market obligations but still want to be dynamically scheduled by the NYISO will be allowed to offer into the energy and ancillary services markets only, following similar obligations to traditional generators

The following table shows the capabilities of the different frameworks to allow demand side resource participation in the NYISO market. The DER framework will provide the largest amount of flexibility and revenue realization for distributed resources. In the future, under the DER framework distributed energy storage will be able to provide DAM Energy, RT Energy , Capacity, and Ancillary Services. Under the current emergency and economic DR frameworks that is not yet possible.

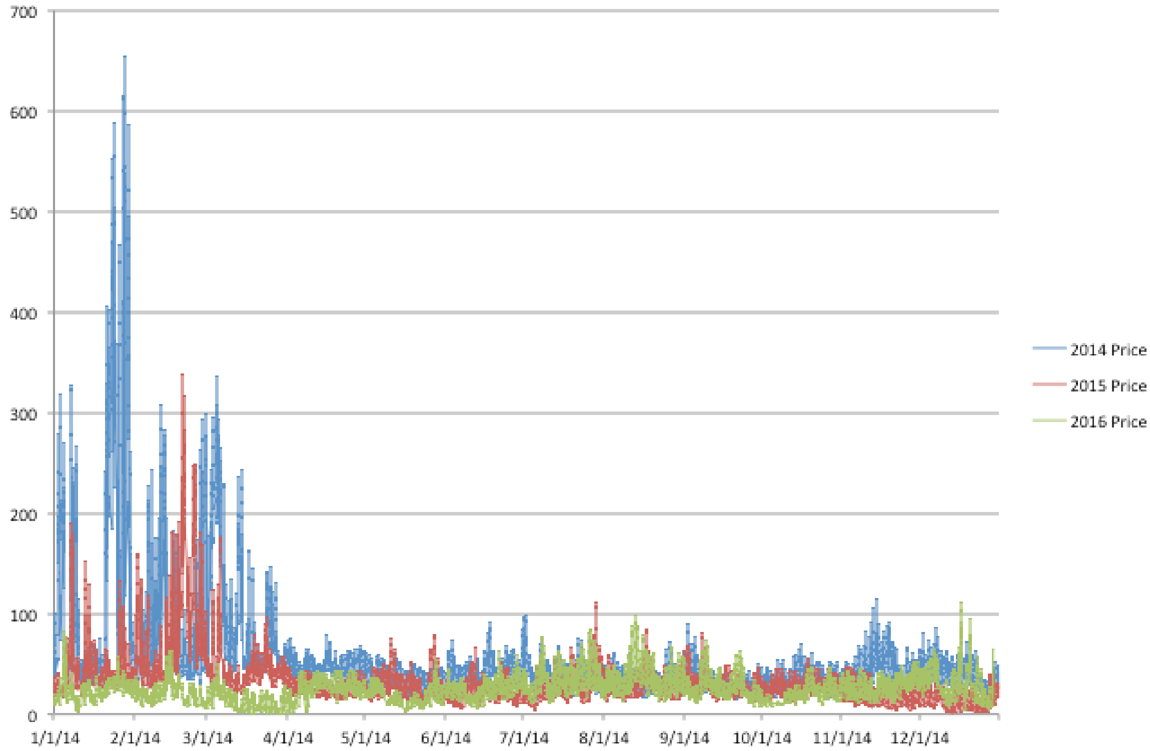
	Distributed Energy Resources			Price Capped Load Bidding
	Dispatchable DER Full, Daytime, Peak	SCR 4 Hour Reliability	EDRP Voluntary Reliability	
	Fully Dispatchable	4 Hour Minimum Reliability	Voluntary Reliability	
DAM Energy	✓ Bidding required if Capacity is sold	✗	✗	✓
RT Energy	✓ consistent with short notice generators	✓ payment available for verified performance	✓ payment available for verified performance	✗
Capacity	✓	✓	✗	✗
Ancillary Services	✓	✗	✗	✗
30 Min Non Sync	must offer if resource/ aggregation is qualified	NA	NA	NA
10 Min Non Sync	must offer if resource/ aggregation is qualified	NA	NA	NA
10 Min Spin	must offer if resource/ aggregation is qualified	NA	NA	NA
Regulation	Optional depending on qualifications	NA	NA	NA
Voltage Support	Optional depending on qualifications	NA	NA	NA

Energy Product Pricing Table (All Prices for Zone J, NYC)

The following pricing table shows the maximum, minimum, and average price for each product in the NYISO from 2014 – 2016.

Product	**2014**	**2015**	**2016**
Day Ahead Market MWh)	$655, $8, $56	$338, $1, $33	$112, $1, $24

NYISO Day-Ahead Market Price (Zone J, 2014 – 2016)



The highest level of energy price volatility has been seen in the winter months. The extreme price spike in 2014 was the result of the "polar vortex", during which there were record low temperatures from January to March. There is typically a larger energy value in NYSIO in the winter, whereas the peak capacity events occur during the summer, as is reflected in capacity, DR, and demand charge prices.

NYISO Ancillary Services Prices Across Zones (2014-2016)

Product Max, Min, Ave)	2014	2015	2016
30 Min Non-Synch ($/MWh)	$50.00, $0.00, $0.43	$9.00, $0.00, $1.23	$35.63, $2.10, $5.12
10 Min Non-Synch ($/MWh)	$192.00, $0.00, $2.67	$44.71, $0.00, $2.15	$35.88, $2.10, $5.12
10 Min Spin ($/MWh)	$199.00, $0.03, $6.58	$118.14, $0.10, $4.81	$35.88, $2.10, $5.45
Regulation ($/MWh)		$134.8, $4.00, $9.22	$521.75, $3.00, $8.31

NYISO 2014-2016 Average DR Prices Across Zones (2014-2016)

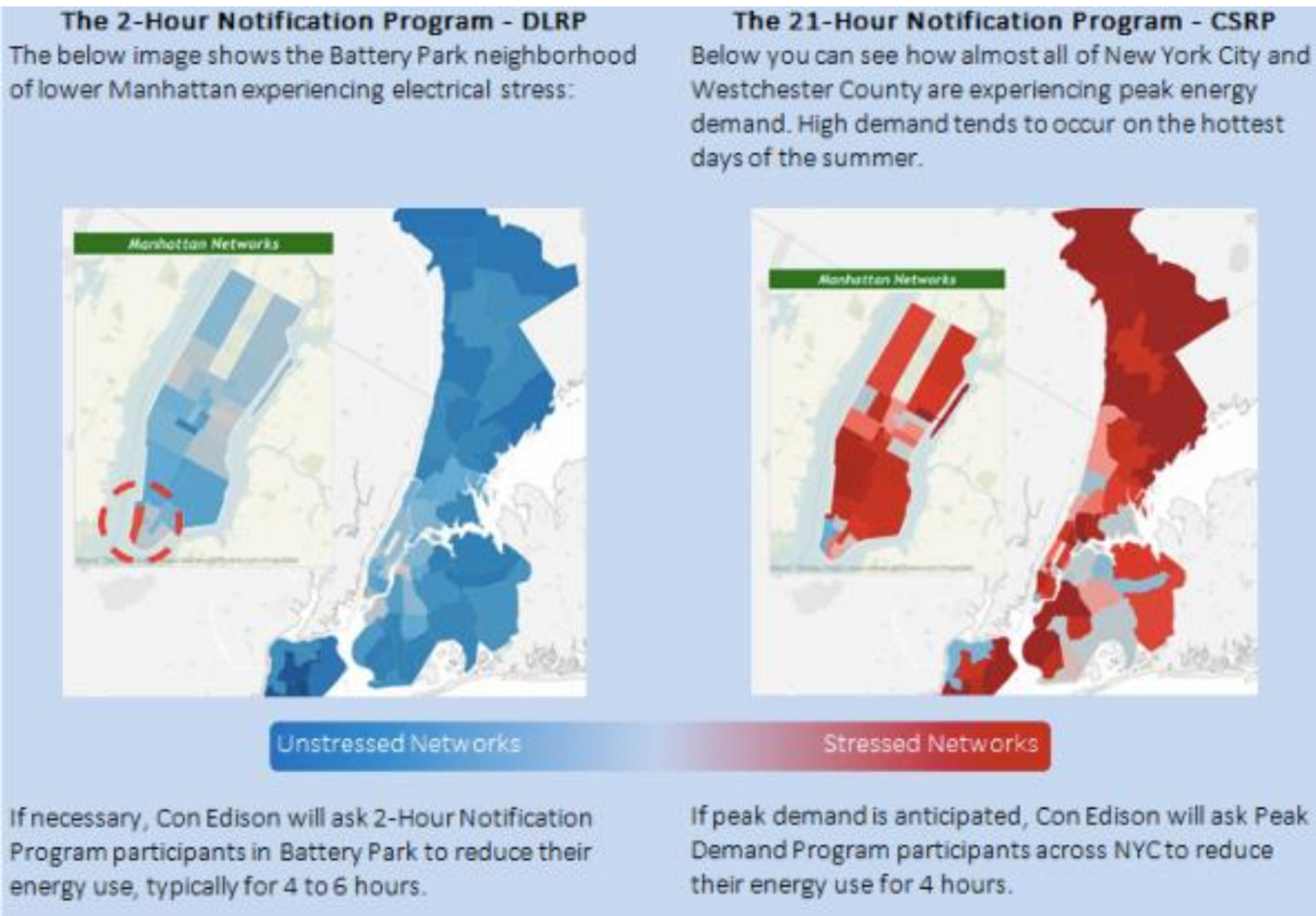
Product	2014	2015	2016
Summer ICAP ($/kW-Mo)	$16.24	$15.50	$10.99
Winter ICAP ($/kW-Mo)	$7.54	$8.45	$6.67
Annualized ICAP ($/kW-Mo)	$144.50	$140.14	$133.02

ConEd DR Programs

In addition to NYISO ICAP SCR, ConEd runs two high value DR programs. Currently, it is already possible for a DR resource to participate in both the ConEd DR programs and the NYISO ICAP SCR.

Distributed Load Relief Program: Customers in this program are called upon to reduce energy use if they are in a specific part of the grid experiencing stress. This program is intended to improve grid reliability.

Commercial System Relief Program: Customers in this program are called upon to temporarily reduce energy use – typically two or three times per year – when energy demand is high. Participation in the 21-Hour Notification Program helps us operate the electric grid more efficiently and potentially save customers money by deferring infrastructure investments.



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[9] ConEd Demand Response Website

Current NYISO Distributed Energy Storage Project Types

Currently, projects installed in NYISO's zones G, J, and K are being installed to perform demand charge management, ConEd DR (CSRP and DLRP), NYISO ICAP SCR DR, and DSASP (if economic).

During the summer months, when DR pricing is the highest, most the battery capacity will be designated to perform DR in the available markets. During the winter months, most the battery capacity will perform DCM. During off-peak hours, the battery system software must decide as to whether the wear and tear of performing ancillary services through DSASP is accretive to project economics.

PJM

ISO Overview

PJM is the first market to open energy storage to wholesale participation with its adoption of FERC Order 755. The FERC Order 755 created the fast frequency response Reg D market which pays resources for a higher performance in their ability to follow the AGC signal. This catalyzed both transmission connected and behind the meter resources to enter the frequency regulation market. Frequency regulation (Reg D) pricing in 2013, 2014 was high enough to support a project on a stand-alone basis, but as more resources have been entering the market, prices have decreased by 20% annually. The demand response market in PJM has been in operation since 2008, and in the 2014/2015 delivery year there were over 9,000 MW participating from on-site generation, refrigeration, HVAC, lighting, and manufacturing.

As in other markets one revenue stream has not been sufficient to support energy storage projects. Behind the meter energy storage projects must stack revenue streams to make site hosts whole and create attractive investor returns.

Market participants in PJM can use energy storage resources to participate in the wholesale market as either generation or demand-side resources. Energy storage resources that are directly interconnected to the transmission system, or interconnected to the distribution system and inject power past the applicable customer meter, are considered to be generation resources. Generation resources go through the PJM interconnection queue to determine the resource's ability to deliver power. In addition to being studied for generation deliverability, electric storage resources are also studied for load deliverability impacts related to their load capability when receiving electricity (i.e. charging).

Energy storage resources located behind a customer's meter receive compensation as demand-side resources, for all energy products other than non-synchronous reserves. To participate in the PJM wholesale markets as a demand-side resource, energy storage resources that are behind a customer's meter typically will be used to decrease a customer's load at the meter, except in special cases. In PJM, demand-side resources participate either as Emergency Load Response or Economic Load Response resources. Emergency Load Response is provided by Market Sellers that are required to reduce load in real-time during an Operating Day if called upon based on their commitments in the Capacity Market (in PJM, the capacity market is called the "Reliability Pricing Model" or RPM). Economic Load Response is provided by Market Sellers that wish to voluntarily reduce load in response to market prices during an Operating Day. Like other types of resources that participate in PJM's markets only by providing load reductions, these demand-side electric storage resources are not studied by PJM through the generation interconnection process. As such, they are not studied for deliverability, and, thus, demand-side electric storage resources are not allowed to inject energy beyond the customer's meter and onto the distribution or transmission system, as applicable.

PJM Overview – Wholesale Products and Energy Storage Participation Obligations

Product Type	Performance Obligations
Capacity Performance	Obligated to deliver energy during the relevant Delivery Year as scheduled and/or dispatched by the PJM during Performance Assessment Hours.
Base Capacity	For the Delivery Years 2018/2019 and 2019/2020,26 obligated provide energy output to PJM as scheduled and/or dispatched during any Performance Assessment Hours occurring in the calendar months of June through September.
Capacity Performance DR	Capacity Performance DR is available for an unlimited number of interruptions during the Delivery Year, and will be capable of maintaining each such interruption between the hours of 10:00AM to 10:00PM Eastern Prevailing Time for the months of June through October and the following May, and 6:00AM through 9:00PM Eastern Prevailing Time for the months of November through April unless there is a PJM approved maintenance outage during October through April.
Base Capacity DR	Base Capacity DR is available for unlimited number of interruptions during June through September in the Delivery Year and will be capable of maintaining such interruption for at least 10-hour duration.
Limited DR	Available for interruption for at least 10 times during the summer period of June through September in the Delivery Year, and will be capable of maintaining each such interruption for at least a 6-hour duration.
Extended Summer DR	Available for an unlimited number of interruptions during an extended summer period of June through October and the following May, and will be capable of maintaining each such interruption for at least a 10-hour duration.
Annual DR	Annual DR is available for an unlimited number of interruptions during the Delivery Year, and will be capable of maintaining each such interruption for at least a 10-hour duration.
Synchronized Reserve	Provide cleared megawatt value when dispatched during a Synchronized Reserve Event within ten (10) minutes, and to be capable of maintaining that output for the entire event, or thirty (30) minutes, whichever is shorter. Two tiers: Tier 1 and Tier 2 Tier 1 - resources are on line following economic dispatch and able to ramp up from their current output in response to a Synchronized Reserve Event, or Demand Resources capable of reducing load within 10 minutes. It is assumed that batteries (as well as other resource types such as nuclear, hydroelectric and wind) are not able to provide Tier 1 Synchronized Reserve, but may ask for an exception by showing they can reliably provide Tier 1 service. Tier 2 - additional capacity that is synchronized to the grid and operating at a point that deviates from economic dispatch to provide additional Synchronized Reserve not available from Tier 1 resources and dispatchable demand-side resources that have controls in place to automatically drop load in response to a signal from PJM.
Non-Synchronized Reserve	Used to economically fulfill the total PJM Primary Reserve requirement, which are 10-minute reserves that can include a combination of Tier 1 and Tier 2 Synchronized Reserves and Non Synchronized Reserves. The primary performance requirements of Non-Synchronized Reserves (10 minutes response

	for a maximum of 30 minutes) is the same as Synchronized Reserves. Demand-side resources, including batteries operating as demand-side resources, are not eligible to provide Non-Synchronized Reserves.
Regulation	Capable of receiving the Automatic Generation Control (AGC) signal (i.e. Regulation signal) from PJM and submit the resource's response back to PJM via telemetry (in a manner determined by PJM, which may vary by resource size). Required to provide a dispatch range of at least twice the amount of Regulation assigned, and the resource must be able to symmetrically provide the total amount of Regulation assigned (a full raise and lower of assigned regulation from set-point). Demand-side resources providing Regulation are required to fulfill the regulation range requirements without injecting energy into the Bulk Electric System (i.e. past the applicable customer meter). Testing is required pursuant to requirements in the PJM Manuals, and all Regulation resources must maintain a 100-hour rolling average performance score of 40% to remain eligible to provide Regulation. A reduction in this average below 40% results in a requalification process. Two Regulation signal types: RegA and RegD with Market Sellers of such resources choosing which signal they would like to qualify for (one or both). RegA - signal is a slower ramping signal that requires longer energy duration in order to follow accurately. RegD - signal is a faster ramping signal that dispatches resources (such as batteries and flywheels) in an energy neutral manner over a short period of time

To date, energy storage projects have participated in the PJM capacity market on a highly limited basis because of the uncapped duration requirement on capacity resources and high penalties for non-performance (up to $3,000/MWh). Storage resources have been well suited for the fast frequency regulation (Reg D) market because of the short duration requirement (15 – 30 minutes).

Additional Details for Behind the Meter AS Participation:

Grid Product	**Framework**	**Obligations**
Synchronous Reserves	Allowed to participate directly, currently 575 MW performing	• Ability to receive and react to a dynamic regulation control signal from PJM, real time telemetry • 100 kW min market offer • Max 33% of total market participation • Non-export, must have load • 1 minute communication interval • If site injected in a specific hour, not eligible to participate as DR for that hour

Regulation Up and Down	Allowed to participate directly, currently 22 MW participating Max market of 700 MW on-peak	• Ability to receive and react to a dynamic regulation control signal from PJM, real time telemetry • 100 kW min market offer • Max 25% of total market participation • Non-export, must have load • If multiple injection events, will no longer be considered a DR resource and will be re-classified as generation • 2 second communication interval • If site injected in a specific hour, not eligible to participate as DR for that hour

Energy Product Pricing Table

Product	**2014 Price**	**2015 Price**	**2016 Price**
Capacity, Zonal Average ($/kW-Yr)	$58.7	$49.9	$60.1

Product	**2014 (Average)**	**2015 Price (Average)**	**2016 (Nov)**
Day Ahead Market ($/MWh)	$49.15	$34.12	$28.21
Synchronous Reserves ($/MWh)	$12.94	$11.88	$3.92
Non-Synch Reserves ($/MWh)	$1.08	$1.03	$3.10
Regulation ($/MWh)	$44.47	$31.92	$4.55

To date, the trend in capacity pricing in PJM is increasing and products in the energy market have been decreasing. The fast frequency regulation (Reg D) market prices have been falling rapidly as market design created a situation in which as more resources bid into the market the market fell. It is widely estimated that the total market size for Reg D under the current construct is 300 – 400 MW.

Current PJM Distributed Energy Storage Project Types

There are currently a very small number of behind the meter energy storage markets performing in the wholesale markets. Demand charges need to be relatively high (larger than $20/kW-Mo) to support distributed energy storage projects. Demand charges and zonal capacity prices are the highest in the Eastern PJM regions. Here, projects can create attractive investor returns by performing DCM on site, bidding into the DR capacity market, and performing frequency regulation during off-hours when DCM or DR would not be available.

There are a small amount of distributed solar projects in PJM performing frequency regulation. These projects apply the ITC to the storage component of the project be charging 75% from solar, then simultaneously perform non-exporting frequency regulation under the FERC 755 Reg D tariff. These projects are relatively risky because the battery system needs to be extremely carefully managed. If the battery charges more than 25% from grid energy it can trigger an ITC recapture event. Additionally, if the battery exports energy it can void its participation in the demand response FR market.