Working Group on Behind-the-Meter Resources, Weather Sensitive Demand Response and Discussion of Comments on the OIR

RA working Group

November 7, 2017

WebEx and Teleconference Info

Call in info: Phone Number: 866-811-4174, Participant Passcode: 4390072#

WebEx:

https://van.webex.com/van/j.php?MTID=me4afaabfe7b5a9c310661dff7339b8ec

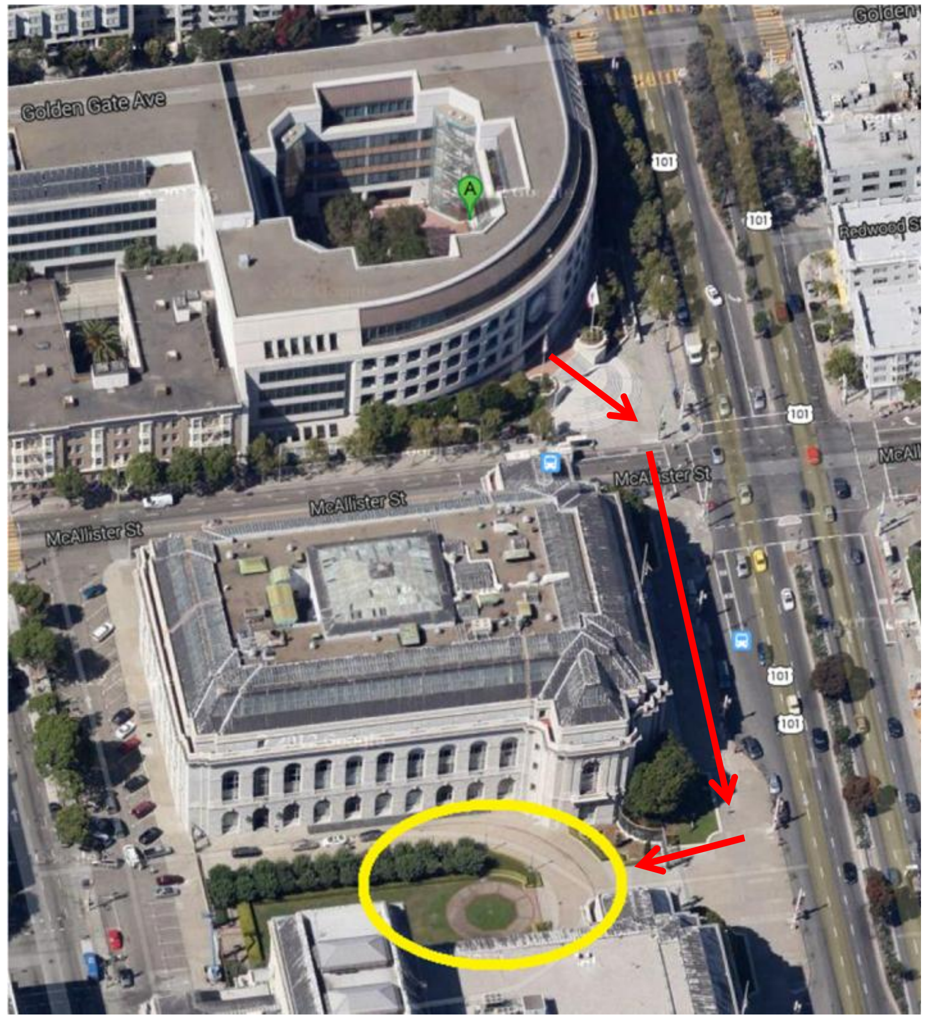
Meeting number: 744 340 055, Meeting password: !Energy1

Note: All phones will be in listen only mode. Please raise your hand through WebEx if you have a question or comment.

Restrooms & Evacuation Procedure

Restrooms are out the hearing room doors and down the far end of the hallway.

In the event of an emergency evacuation, please cross McAllister Street, and gather in the Opera House courtyard down Van Ness, across from City Hall.



Agenda

10:00 am – 10:10 am - Introductions and Announcements

10:10 am – 11:20 pm – Accounting for Behind-the-Meter Resources in the RA Construct

- Current Accounting Methods for Behind-the-Meter Resources (existing, incremental, and third-party contracts)
  - Energy Efficiency
  - Demand Response
    - Load modifying
    - Supply side
  - Distributed Generation

How should we account for the new generation procured through LCR RFOs (3rd party contractors)? These resources include: EE, DR, and DG.

11:20 am – 12:30 pm – How should we account for BTM PV in ELCC and in the RA construct?

- ELCC background and adopted methodology
- Should we change the treatment of BTM PV in the calculation of ELCC?
- If yes, should we also change the RA program to base the RA obligation on a consumption forecast vs. a sales forecast?
  Should the RA obligation be set relative to an LOLE study or continue to be based on peak load plus a static PRM?

12:30 pm – 1:30 pm – Lunch

1:30 pm – 3:00 pm – Weather Sensitive Demand Response

- Load Impact Protocols and weather sensitive DR
- Should weather sensitive DR be treated as a variable resource?
- Are the current QC values appropriate?

3:00 pm – 3:45 pm – Priorities for the RA Proceeding in 2018

- Summary and discussion of comments received on the R.17-09-020 OIR

3:45 pm - 4:00 pm – Wrap-Up/Next Steps

Accounting for Behind the Meter Resources in the RA Load Forecast Process

D.17-06-027 directive

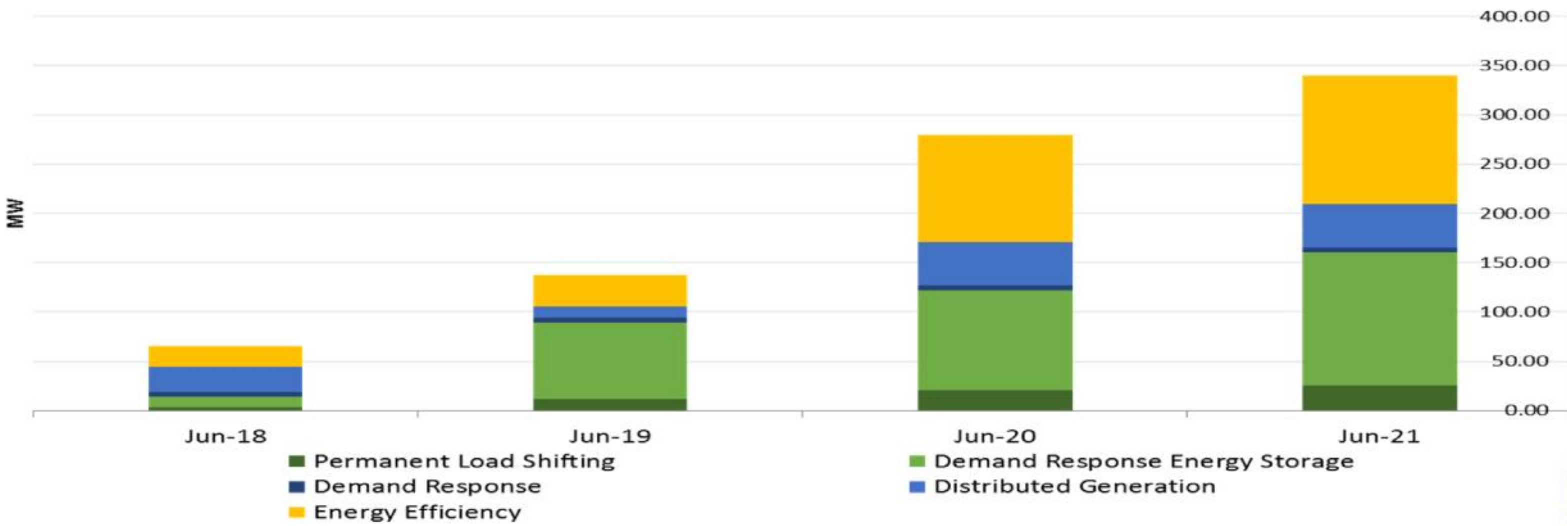
“Energy Division shall coordinate the creation of working groups on the issues of Removal of the Path 26 Constraint, Weather Sensitive Demand Response, **Existing Demand Side Load Impacts**, and Seasonal Local Resource Adequacy.” (OP 8)

“The working group will submit its analysis and recommendations to the proceeding considering 2019 compliance.” (p. 27)

Recap of R.14-10-010 Proposals

Proposal 3 – Allocation of incremental demand side impacts

- In D.15-11-041 the Commission adopted SCE's LCR LA Basin procurement application (A.14-11-012) which consisted of 351.77 MW of behind the meter demand side resources. These resources include Distributed generation (DG), Demand Response, Energy Efficiency (EE), and Storage. The procurement of these resources was considered incremental to the existing demand side programs. The approved cost allocation of these resources followed the existing cost allocation for behind the meter resources.
- The graphic below illustrates the anticipated COD dates of SCE's BTM LCR resources (these values are cumulative).



Recap of R.14-10-010 Proposals

Proposal 3 – Allocation of incremental demand side impacts (cont.)

Issue- There is no current mechanism in the load forecast process to allocate the local, system and flexible capacity benefits, associated with these resources, to load serving entities in the year ahead and intra-year time frames.

In order to ensure that these new resources were counted for 2018 RA compliance, staff allocated ~ 70 MW (that will be online in 2018) as a LCR credit in annual allocation process. Similar to a RMR credit.

Table 8- Year Ahead CAM and RMR values (MW)					
Month	**Jan-18**	**Feb-18**	**Mar-18**	**Apr-18**	**May-18**
SP26 CAM Capacity					
NP26 CAM Capacity					
NP26 Condition 2 RMR					
SCE Preferred LCR Credit					

Allocation of Current IOU demand side programs

Existing Demand side programs get counted through the annual load forecast process. For EE and DG only the incremental benefits are allocated. For DR all the load modifying RA benefits are allocated this way.

Element	Service Area	Jan-18	Feb-18	Mar-18	Apr-18	May-18
EE/DG/DR Adjustment	SCE					
	SDGE					
	PGE					
Pro rata adjustment to match CEC forecast within 1%	SCE					
	SDGE					
	PGE					
Final Load Forecast for RA Compliance	SCE					
	SDGE					
	PGE					
	Total	-	-	-	-	-

Demand Response

- **IOU run Programs**
  - Load Modifying (~ 567 MW for Aug. 2018)
    - Load Impacts, filed in April, are used to determine qualifying capacity value
    - IOUs provide historical load forecast reflecting ex post load impacts to the CEC for use in the load forecast
    - LSEs are credited for these programs through a adjustment to their load forecast
  - Supply Side (~ 1,515 MW for Aug. 2018)
    - Load Impacts, filed in April, are used to determine qualifying capacity value
    - IOUs provide historical load forecast reflecting ex post load impacts to the CEC for use in the load forecast
    - LSEs are credited for these programs through a DR RA credit counted towards meeting their RA requirement
- **Third Party Contracts (DRAM, LCR, PRP)**
  - Include both Load Modifying and Supply Side (~182 MW for Aug. 2018 DRAM, ~26 MW of LCR DR for Aug. 2018)
    - Qualifying capacity values are based on contract value
    - No load impacts filed with the CEC or IOU for these contracts
    - LSEs are credited for DRAM (supply side DR) through a CAM credit.
    - Not sure how to credit LCR DR resources (both load modifying and supply side)

Energy Efficiency (EE)

- **Existing IOU Programs**
  - Committed/existing – included in the base-line CEC demand forecast. Also, included in the individual LSE forecasts.
    - IOUs currently periodically report EE impacts to CPUCs data tracking system
    - Evaluation Measurement and Valuation (EM&V) studies evaluate the programs and adjust the baseline forecast
- **Incremental (Additional Achievable (AAEE))**
  - Included in the managed CEC demand load forecast. These values are allocated pro-rata among all LSEs by TAC area.
- **Third Party EE (LCR, PRP or other future RFOs (IDER))**
  - Reporting EE contract impacts:
    - How do we get third party EE reported for tracking purposes?
  - Evaluation of EE contracts:
    - How will we ensure the EE programs are evaluated in the same ways as existing EE programs(are vetted)?
    - Incrementality - how do we ensure they are not already being included in the AAEE based on potentials and goals study and adopted goals?

Distributed Generation

- **Existing**
  - CEC forecasts the impacts of the BTM PV and adds these impacts to the sales forecasts to determine a consumption forecast. The baseline demand forecast includes the existing BTM PV.
- **Incremental**
  - Included in the managed CEC demand load forecast. These values are allocated pro-rata among all LSEs by TAC area (similar to AAEE).
- **Third Party Contracts (LCR, PRP, & IDER) paid for by all customers**
  - Don't have a way to allocate
  - Not included in the current CEC forecast process

Other Solicitations and Applications that May Yield Similar Resources

- **SDG&E Preferred LCR (Approved EE contract and pending DR contract)**
- **Preferred Resource Pilot 2 (PRP 2) A.16-11-002**
  - SCE seeks approval of 125 Megawatts (MW) of preferred resources that interconnect to the Johanna-Santiago region located in the Western LA Sub-Area (60 MW – In front of the meter energy storage, 55 MW- demand response/energy storage, 10 MW – behind the meter photovoltaic/energy storage).
  - This procurement may offset 124.9 MW of SCE's current residual 169.4 MW LCR procurement requirement with resources sited in the local J-S Region.
  - Decision on A.16-11-002 is expected Q4 2017.
- **Integrated Distributed Energy Resource (IDER) Procurement**
- **Additional authorized procurement from LCR decisions D.13-02-015 and D.14-03-004**

Discussion Questions

- Should the allocation of demand side resources flow through the load forecast process or a supply side credit:
  - What processes need to be established to ensure that these resources get counted in the annual load forecast process?
  - Does a process need to be established to report the impacts of third party DR to the CEC and IOUs so that it gets added back into the load forecast process?
  - How do we ensure these resources get accounted for in our existing demand side resource forecasting and evaluation process (e.g. AAEE, incremental DG, load modifying DR) ?
  - What is the anticipated growth of this type of resource procurement (LCR, PRP, IDER, DRAM)?

Recap of R.14-10-010 Proposals

Proposal 4- Accounting for Existing Demand Side Impacts in the Annual Load Forecast Adjustment Process

Background :

In the establishing the RA framework, Phase II of R.04-04-003 outlined how EE, DR, and DG programs should be accounted for in the load forecast. A phase II RA workshop report addressed the quantification of EE, DR, and DG impacts and the allocation of those impacts to LSEs. The phase II workshop process clarified that in order for the CEC to determine what level of EE, DR, and DG impacts should be used to adjust an LSE's preliminary load forecast, the LSE must document any such impacts it believes are already included in the preliminary load forecast and provide a methodological rationale supporting this belief. (D.05-10-042 pg. 84)

Issue:

Once a demand side resource is operational, and therefore included in an LSE historical meter data, there has to be a transparent way of reporting the demand side impacts of the resource back to the CEC. This needs to be done in order to equitably allocate any associated capacity benefits to benefiting LSEs and to adjust load prior to making a LSE specific coincident adjustment to the year-ahead load forecasts. D.05-10-042 identified this need (as noted in the background) and it has become clear that there is no consistent reporting (by all LSEs) of demand side resources to the CEC for use in the existing RA load forecast adjustment process.

Recap of R.14-10-010 Proposal

Proposal 4- Accounting for Existing Demand Side Impacts in the Annual Load Forecast Adjustment Process (cont.)

Proposal-

- By March 15th of each year IOUs (and DER providers) send historical hourly demand side impacts for DR, DG and EE to LSEs (ESPs and CCAs) that serve load in the IOUs territory
- These same demand side impacts would have to be sent to the CEC for use in the annual load forecast adjustment process
- These load impacts would be included in year-ahead load forecast submission

Recap of Parties Comments/Concerns

- **PG&E**
  - Timing of the DR LIP report will create an issue. Suggests moving the due date to April 1st.
  - Until there are vetted approaches for developing hourly DG and EE profiles the scope of reporting should be limited to DR.
  - Recommends ED led workshops, with CEC involvement, to discuss methods for determining hourly DG and EE profiles.
- **SCE**
  - Concern with the difficulty in obtaining DG performance data.
  - Concern with timeline of reporting.
  - Confidentiality concerns.
- **SDG&E**
  - Recommends ED staff work with other IOUs to ensure consistent methodologies in developing ex-post EE load shapes.
  - No concern with providing EE and DG data for 2018 YA load forecast.

Discussion Questions

- What is the current magnitude (in MWs) embedded in the load forecast (EE, DR, DG)?
- For third party DR contracts how do we ensure we are not double counting?
- What are the major issues if we do not address this?
- What are the major benefits of addressing this (for each resource type)?
- Does there need to be consistent methodologies for forecasting demand side resources in individual LSE forecasts?

Thank You!

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BTM resources and ELCC in RA

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11-7-17

Objectives and Outline

- Objective of working group session – provoke thought, ask questions. This is not a proposal
- Consumption versus Sales – why are we doing this at all?
- Current Status of RA obligations and QC for DG resources
- Case study - treatment of BTMPV in RA
- ELCC – Background and Adopted Methodology
- Questions/Answers
- Calculation of RA obligation with LOLE study
- Questions/Answers

Consumption versus Sales - Background and Definitions

- Consumption and Sales – Raw load versus Net Load
- RA obligation currently set relative to sales. DG and EE assumptions are part of the CEC's analysis to produce sales forecasts, peak and total energy.
- Changing to consumption forecasts create a host of difficulties
- Why think about changing?
- Definitions - Four Load Types

Term	Definition
Consumption	Sum of electrical energy consumed by end-uses excluding storage charge/discharge
Sales	Consumption net of BTM generation on site plus net of charge/discharge of storage
System Load	Sales plus transmission and distribution losses plus theft and unaccounted for
System Net Load	System Load less generation from non-controllable system generation

Consumption Shapes - Advantages

- How to accurately verify reliability contributions of supply side generation without conflating effects of BTM generation?
- Weather Normalization – accurately predict customer electric demand from weather data. Prediction is significantly confused by DG impacts mixed in with historical customer electric demand information
- Determine value of DG generation to meet customer demand – how valuable is it compared to supply side generation investment?
- IRP is considering modeling with consumption shapes and BTMPV treated as generation, like utility-scale solar. This may better align with need to consider interactive effects of BTMPV on solar ELCC, but differs from current RA modeling treatment. RA and IRP modeling treatment could be aligned.
- DG impacts, led by BTMPV impacts, are large and getting larger. (projected 5,500 MW of BTMPV by 2018)

Consumption Shapes - Disadvantages

- Refer to earlier presentation - Jaime provided good discussion of data access/coordination issues
- Utility Distribution Companies (UDCs) capture consumption and DG hourly data, other LSEs don’t – how to provide LSEs with data so they can prepare their load forecasts?
- How to use consumption forecasts in RA program – RA credit for DG resources?
- Not a simple change – forces consideration of structure of RA program

    Case study – BTM PV in ELCC calculations

Consumption Shapes – RA Implementation Issues

How to implement within RA Program structure?

- PRM is applied as margin over peak load – which peak load? Consumption or Sales?
- Data access – how to reconstitute consumption hourly values? Back out DG generation including BTMPV by the hour
- All LSEs (not just UDCs) file forecasts/meet RA obligations?
- ELCC/Qualifying Capacity (QC) for DG/BTMPV resources?
- Add BTMPV to NQC list or allocate capacity credit to LSEs through load forecast adjustments?

Allocation of IOU DG and DR programs

- Other EE and DG programs are allocated to LSEs through adjustment to load forecasts.

- Moving to consumption shapes for RA obligations requires backing out effects of DG/DR programs, studying consumption forecasts, then giving credit back to use against RA obligations

- What impacts are allocated? Nameplate/QC/ELCC?

Element	Service Area	Jan-18	Feb-18	Mar-18
EE/DG/DR Adjustment	SCE			
	SDGE			
	PGE			
Pro rata adjustment to match CEC forecast within 1%	SCE			
	SDGE			
	PGE			
Final Load Forecast for RA Compliance	SCE			
	SDGE			

Recap of Current RA obligations

- RA obligations are currently equal to peak load (sales) plus a static 15% planning margin in each month.
- RA obligations are met by summing contracted capacity. Capacity is measured against Net Dependable Capacity, Exceedence Method, or ELCC depending on type of RA capacity

Background and Current Methodology – BTM PV in ELCC

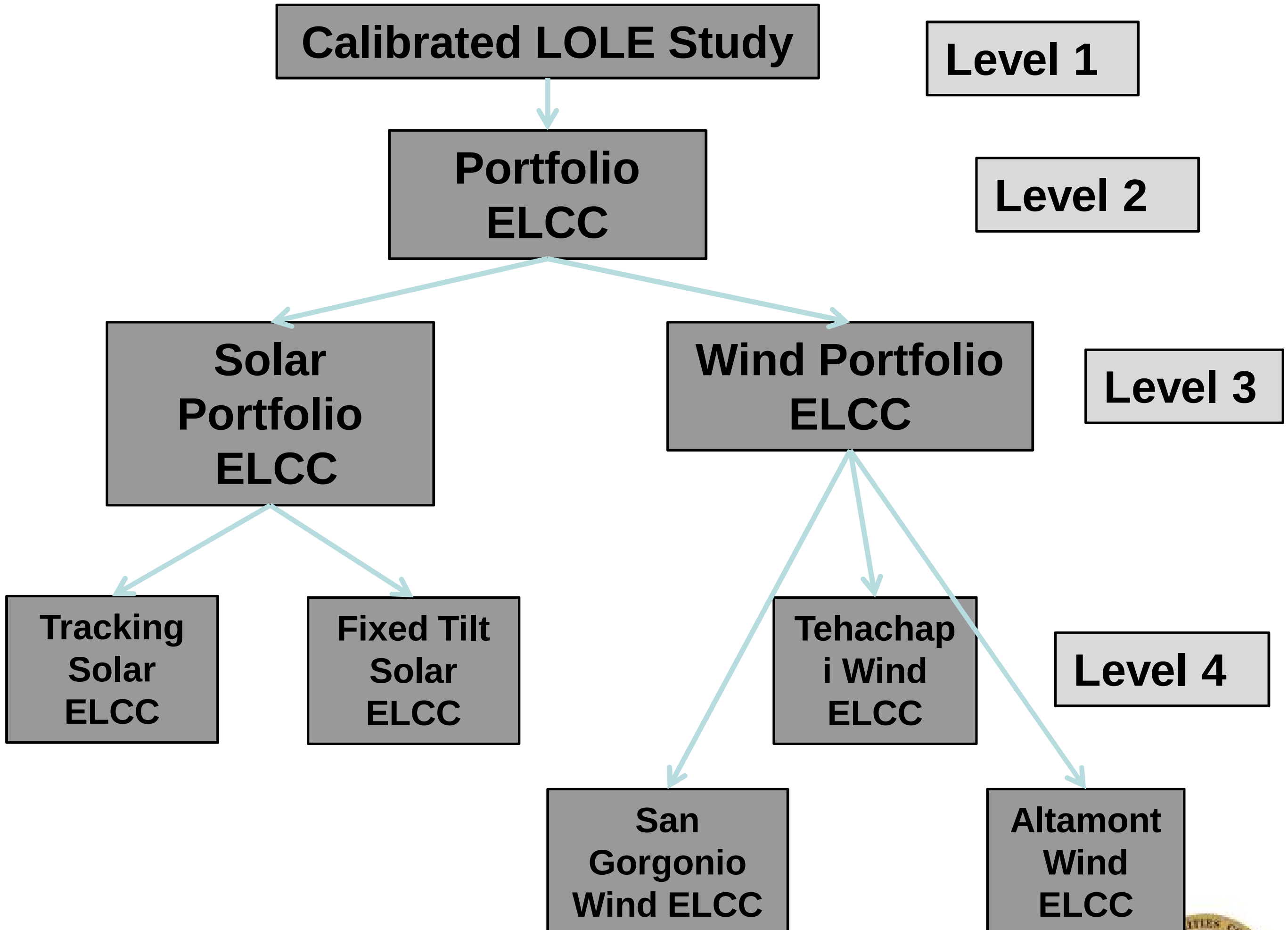
- Effective Load Carrying Capability (ELCC) values for wind and solar generators adopted in D. 17-06-027
- ELCC study found Perfect Capacity equivalent to all supply side and BTM PV as one block, then backed out effect of BTMPV moving from bottom of ELCC curve upwards – BTMPV is last segment added
- How to study Supply Side PV without conflating effect of BTMPV on total ELCC?

LOLE – ELCC Terms and Definitions

- Loss of Load Expectation (LOLE) reflects the expected number of Loss of Load Events – frequency but not duration or magnitude
- Loss of Load Hours (LOLH) represents the expected total duration of Loss of Load Events, not frequency or magnitude
- LOLH/LOLE equals the average duration of each outage event in hours
- Standard industry metric LOLE – 0.1 total Loss of Load Events per year or 0.1/12 per month
- Effective Load Carrying Capability (ELCC) – ability of a resource or resource class to offset LOLE/LOLH events by providing generation or load reduction. Expressed as ratio of MW equivalent Perfect Capacity to MW of real resource or resource class
- Both LOLE/LOLH and ELCC are products of probabilistic reliability modeling – both are expressed as expected value

Order of Studies - Process

- ELCC studies follow an order – results cascade
- Results of one level serve as control totals for the lower
- Each level is more granular than the previous – can be broken into technological or locational subcategories
- Current adopted ELCC stops at Level 3



Process - Series of Studies

- Loss of Load Study – levelize reliability risk across all twelve months (Monthly LOLE study)
- Determine reliability value of all wind and solar generators in a group (Portfolio ELCC)
- Determine standalone value of wind and solar generators individually (Standalone Solar and Wind ELCC)
- Total of Standalone ELCC values should equal Portfolio ELCC – difference between total Standalone ELCC and Portfolio ELCC is Diversity Adjustment
- Final ELCC is Standalone ELCC plus Diversity Adjustment

Setting RA Obligation

Current disconnect between ELCC methods and calculation of RA obligations

- ELCC study calculates ELCC, then adds up to meet RA obligations arithmetically determined by peak load plus static 15%
- Does not use results of LOLE study used as baseline for ELCC study
- Current Calculation of RA obligations and QC disconnected from IRP process – benefits in comparing IRP and RA studies with same study frameworks

Framework of Possible Proposal - RA obligations set with LOLE study

- Requires changes to the overall structure of the RA program
- Go from peak load plus 15% PRM to Effective Capacity Level needed to maintain levelized LOLE each month
- Allocate RA obligations to individual LSEs based on methodology TBD
- Calculate ELCC values for other types of resources to use in meeting RA obligations
- Need to do the modeling before articulating a proposal

Thank You!

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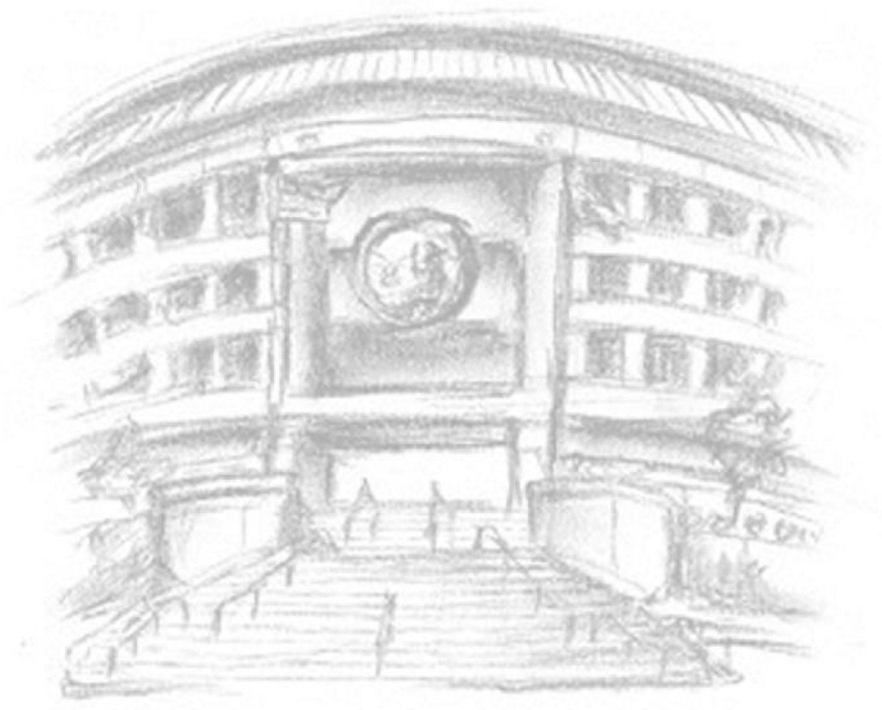

Priorities for the RA Proceeding

Topics Identified

- Reevaluation of RA Framework
- Local Capacity Requirements
- Flexible Capacity Requirement
- ELCC
- Multi-year RA Requirement
- RA Schedule
- Out-of-Market Procurement
- Other

Reevaluation of RA Framework

- General consensus that it is time to comprehensively review the RA framework
- 18+ months needed
- Less consensus on priorities
  - Comprehensive look at requirements, counting rules, load forecast, multi-year requirement, resource retention/retirement (Joint Utilities, CAISO)
  - Modify or eliminate flexible requirement (Sierra Club, CEERT, CEDMC)
  - Centralized capacity market (Calpine, WPTF)
  - 2 hr product, reassess MCC buckets, unbundle EFC and NQC (JDRP)
  - Eliminate monthly requirement (Calpine, WPTF)

Local Capacity Requirements

- LA Basin vs. San Diego/IV requirements and costs (SDG&E)
- More time for evaluation of study needed (Joint CCAs, CEERT)
- Rules for counting of local DR with >20 min response time (CAISO, JDRP, CEDMC)
- Adoption of sub-area requirements (Calpine, WPTF)
- Aggregation of LCRs (CEDMC)
- Adoption of CAISO sensitivities (Cogentrix)
- Seasonal local requirements (CEDMC, Sierra Club)
- Is a 1/10 N-1-1 planning standard too stringent? (Sierra Club)

Flexible Capacity Requirement

- More time for evaluation of study needed (Joint CCAs)
- Tighten eligibility for EFC (Cogentrix)
- EFC for combined resources (solar or wind + storage) (EDF-RE)
- One hour flexible product (CESA)
- Downward ramping product (CESA)

ELCC

- Methodology for BTM solar (ORA, Calpine, WPTF)
- Add technological and/or locational factors (ORA, EDF-RE)
- Adopt an approved ELCC methodology (ORA)
- Reconsider use of “perfect capacity” (Joint CCAs, TURN)
- Consider higher planning reserve margin (Calpine)
- Consider alternative to 1/10 year reliability standard (TURN)

Multi-year RA Requirement

- Consider multi-year requirement (ORA, CAISO, JDRP, NRG, IEPA, Cogentrix)

RA Schedule

- Many parties support an earlier RA decision and earlier release of the NQC/EFC lists and RA Guide and templates (SDG&E, Joint CCAs, Calpine, Cogentrix, AReM, Shell)

Out-of-Market Procurement

- General theme in comments that we should given recent RMRs there is a need address out-of-market procurement
- Need to ensure that conflicts between RMRs and the bilateral RA market are avoided

Other

- Coincidence adjustment (Joint CCAs)
- Amount of excess capacity IOUs can have (Joint CCAs)
- RA requirement based on peak for summer and net peak for winter (JDRPs)
- Determine availability assessment hours in RA proceeding (JDRPs)
- QC Values for combined resources (JDRPs)
- Eliminate one LSE requirement (JDRPs)
- Rules for IOU purchase of capacity from ESPs (AReM)
- MOO for combined resources (CESA)
- Disadvantaged communities and loading order requirements for RA (Sierra Club)
- Examine potential withholding (Sierra Club)
- Weather sensitive DR (CEDMC)
- Allow capacity for energy swaps with Pacific Northwest (CEERT)
- Authorize a Preferred RFO for Moorpark (CEERT)

Thank You!

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