Slow Response Local Capacity Resource Study
CAISO-CPUC Joint Workshop

October 3, 2016

Agenda

Time	Topic	Presenter
10:00 – 10:15	Introduction and purpose	• Commissioner Florio, CPUC • John Goodin, CAISO
10:15 – 12:30	Joint IOU & CAISO's TPP special study on DR in local areas	• CAISO • Joint IOUs
12:30 – 1:15	Lunch	
1:15 – 3:45	Process & Implementation Discussion	Moderator: Matthew Tisdale
3:45 – 4:00	Wrap up and next steps	Commissioner Florio, CPUC John Goodin, CAISO

What brings us here today?

- ISO proposed a BPM change to clarify that local RA energy-limited resources be dispatched within 20-minutes post-contingency to preserve limited availability.
  - A pre-contingency dispatch framework for energy-limited local RA resources did not exist
- BPM change appealed, with executive appeals committee decision deferring BPM implementation and directing staff to conduct technical studies to define energy requirements of pre-contingency dispatch resources to meet local RA requirements.
  - This work is underway in the ISO's Transmission Planning Process
- Decision directed ISO to conduct a joint workshop with CPUC to address how slow response DR can help the ISO effectively address NERC, WECC and ISO reliability standards applicable to local areas.

What brings us here today? (con't)

On a parallel track, CPUC RA decision (D16-06-045) sought to:

1) Consider how to allow DR to count as local RA by:
   - Clearly defining what "sufficient energy" means;
   - Identify a method to ensure that resources are not overly dispatched pre-contingency without good cause,
   - Clarify operating procedures for post-contingency notification, ensuring equal treatment for all resources,
   - Explore mechanisms for a rapid "pre-notification" to provide maximum warning to scheduling coordinators that a post-contingency dispatch is being considered, and
   - Identify a method to calculate the portion of a slower responding DR program that can reliably respond within the required period, and therefore be counted for Local RA.
2) Implement any necessary procedures, system changes or other needed changes at the CAISO, and
3) Convene a working group to make recommendations for any related changes to the CPUC's RA or other programs.

Today's Workshop Objectives

1. Review preliminary results and inputs and clarify details about the slow response local capacity resource study.

2. Outline slow response local capacity resource study process for current and future years; and

3. Discuss alignment between slow response resource capabilities and local capacity needs.

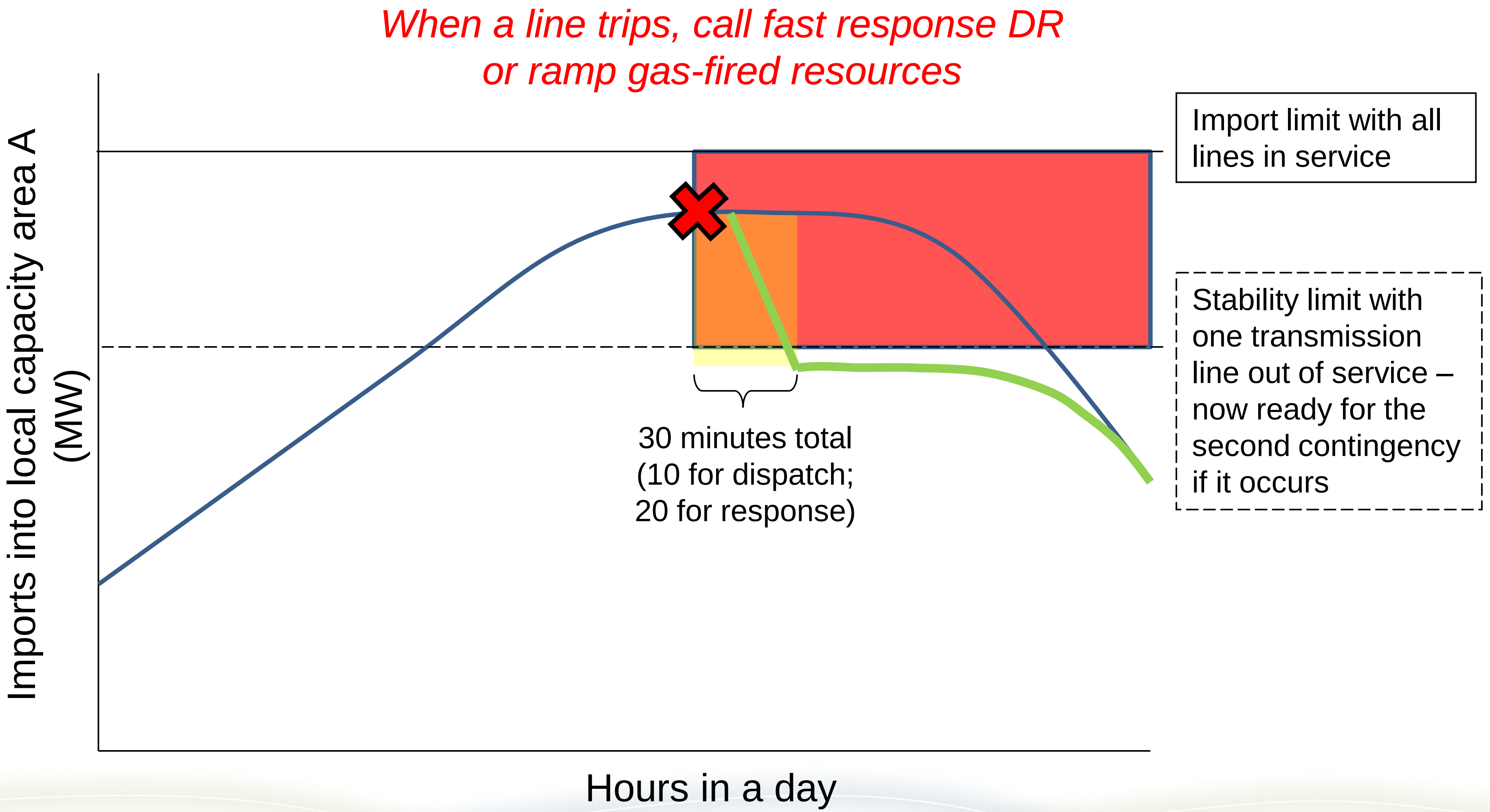
Slow Response Local Capacity Resource Study Overview

- The concept being studied
- Study overview: purpose, assumptions, and methodology
- IOU data overview
- ISO study details and results

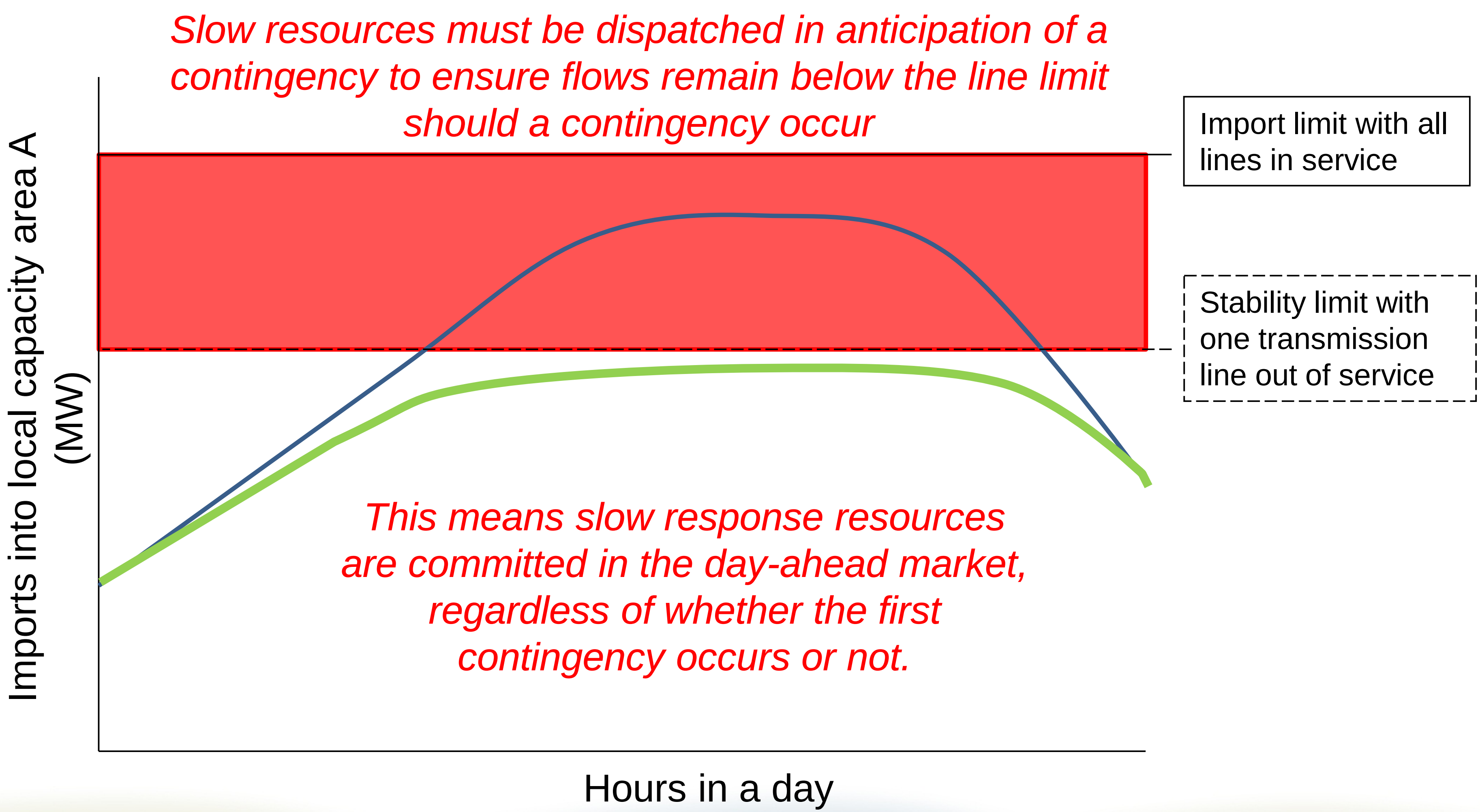
Planning and operating criteria call for the system to be reliable for the next contingency, and after one contingency, promptly prepare for the next.

- **Time allowed for manual readjustment:** This is the amount of time required for the operator to take all actions necessary to prepare the system for the next contingency. This time should be less than 30 minutes, based on existing CAISO Planning Standards, CAISO tariff, and NERC standards for stability limits.
- Based on requirement to reposition the system within 30 minutes, the ISO has two options:
  1. By assessing the system and issuing a dispatch instruction and have a response within 20 minutes
  2. By dispatching a resource pre-contingency so as to have sufficient energy available

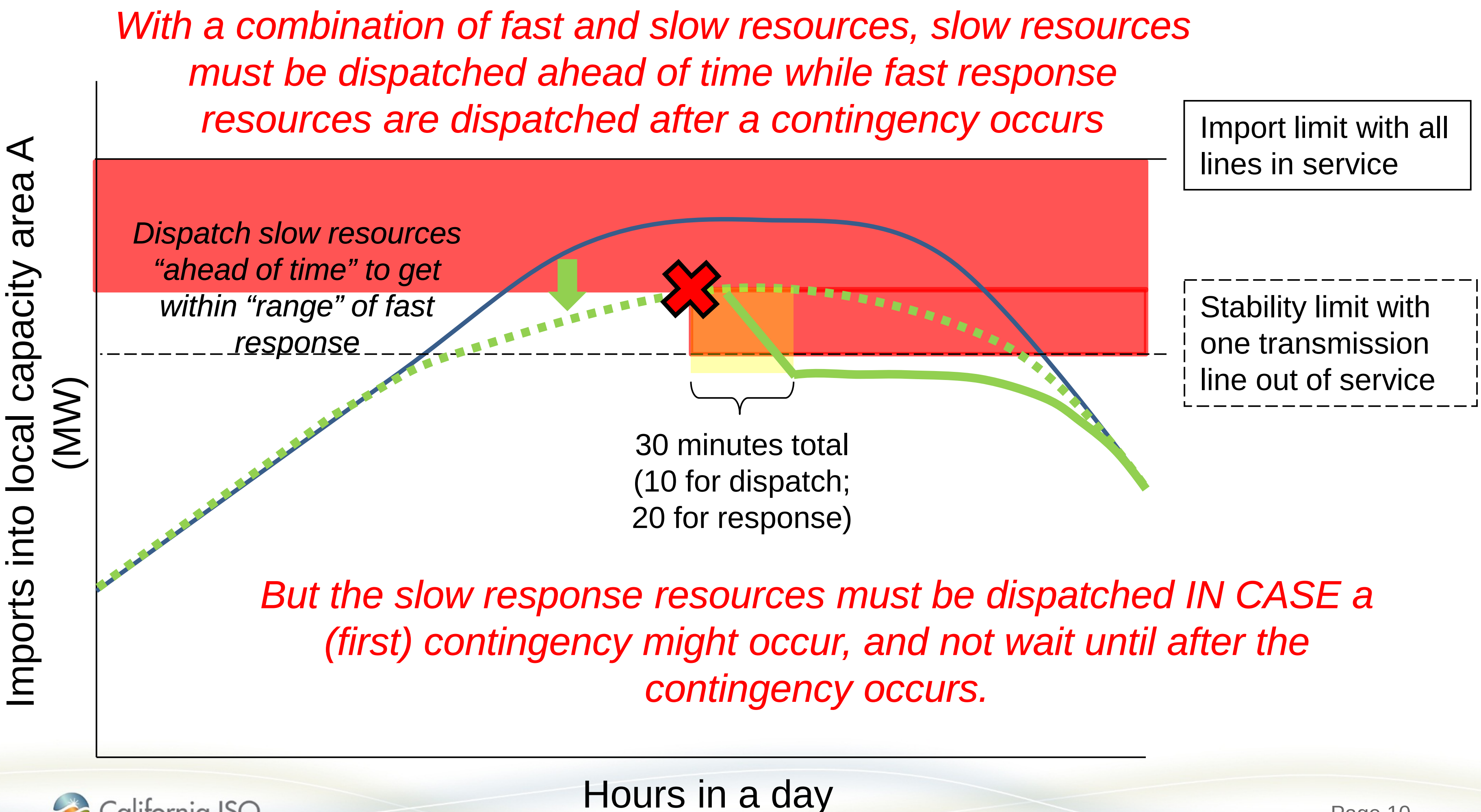
Currently, fast response resources – or the available ramping of slower resources - are generally utilized to restore local areas to prepared for the next contingency:



Slow response resources can play a role if they can be dispatched ahead of the first contingency, "in case":

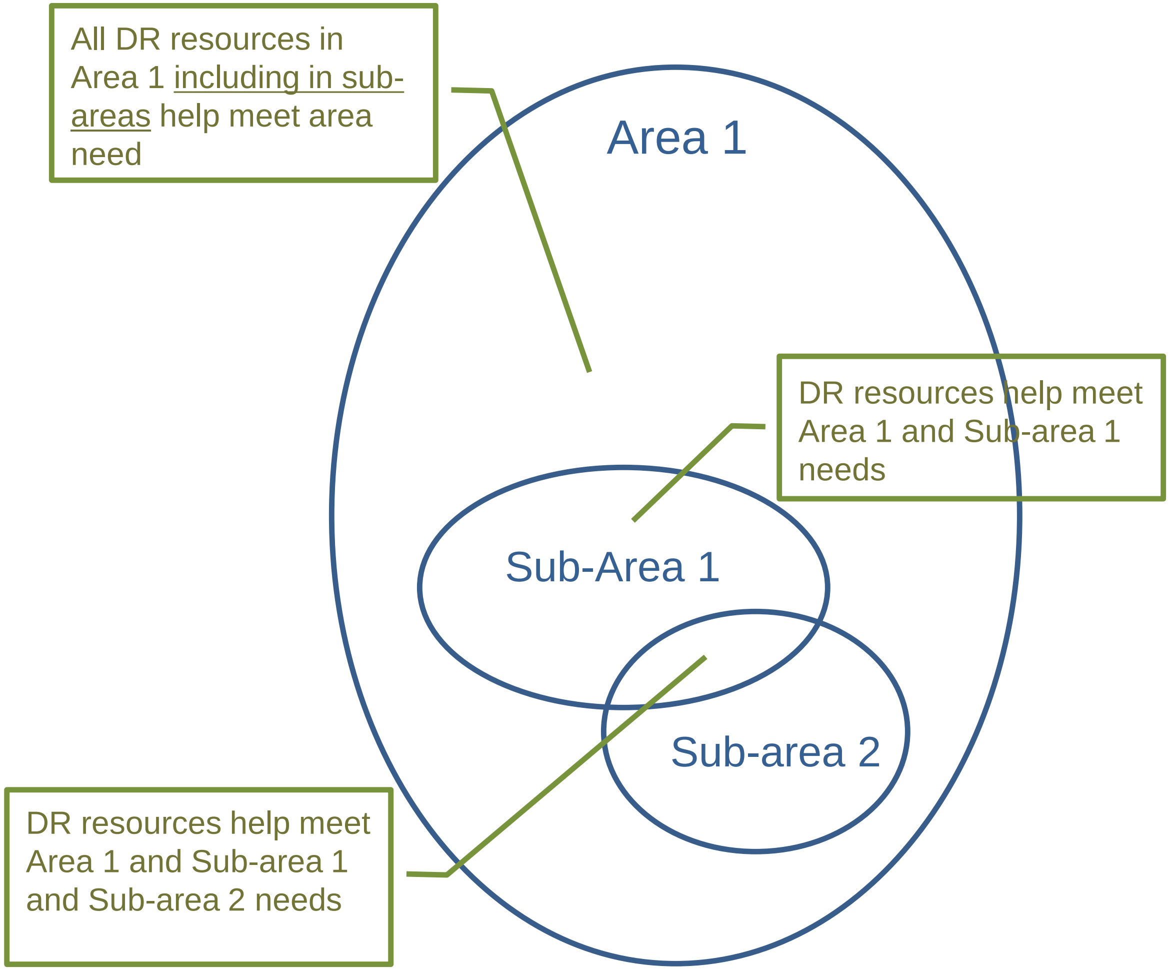


A combination of fast and slow resources can work together, providing the slow response resources are dispatched appropriately:



The boundaries are established through transmission system limitations that define the area or sub-area boundaries

- While annual "local RA" is only procured on an "area" basis, sub-area needs must also be addressed
- Long term planning requirements apply equally to area and sub-area needs
- Area and sub-area boundaries are not the same as sub-LAP boundaries



Characteristics of Slow Response Local Capacity Resources Special Study

Methodology

Nebiyu Yimer, Regional Transmission Engineer Lead

October 3, 2016

Introduction

- The study assesses availability requirements for slow-response resources (such as DR) to count for local resource adequacy including:
  - annual, monthly and daily event hours
  - number of events per month, day and consecutive days
  - operating times (days of the week, hours of the day)
- The study evaluated results against existing DR program characteristics
- The study assumes
  - slow response resources will be dispatched in anticipation of loading conditions that would cause reliability issues if contingencies occurred.
  - they are called last and therefore have the lightest possible duty.
  - idealized “perfect” forecast and local area dispatch capabilities – operational implementation issues are not in the study scope

Methodology

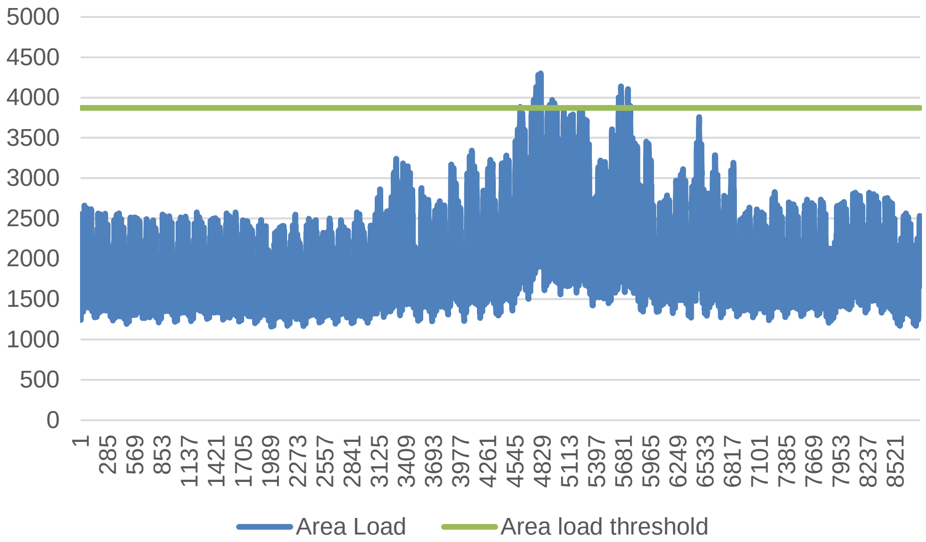
- LSEs selected LCAs and sub-areas to be studied and provided assessment using Method 1 (Step 1) – which assumes all resources are equally effective within a study area
- ISO:
  - reviewed LSE results
  - verified selected results using Method 2 (Step 2) – which tests locational and reactive capability impacts within the study area
  - evaluated results against existing DR program characteristics
- Study is based on hourly load data for 2017 derived from 3-5 years of historical data.
- 3-year maximum values are used

Study scope

Performer	Areas studied	Slow-response resource amounts studied
SCE	- All LCAs, - All sub-areas	- Existing DR (Slow Response) - 2% of study area load - 5% of study area load - 10% of study area load
PG&E	- All LCAs	- Existing DR (Slow Response) - 2% of study area load - 5% of study area load - 10% of study area load
SDG&E	- San Diego sub-area	- Existing DR (Slow Response) - 1% of study area load - 3% of study area load
ISO	- LCAs and voltage stability limited sub-areas in southern California	- Existing DR (Slow Response) - Reviewed and evaluated all results

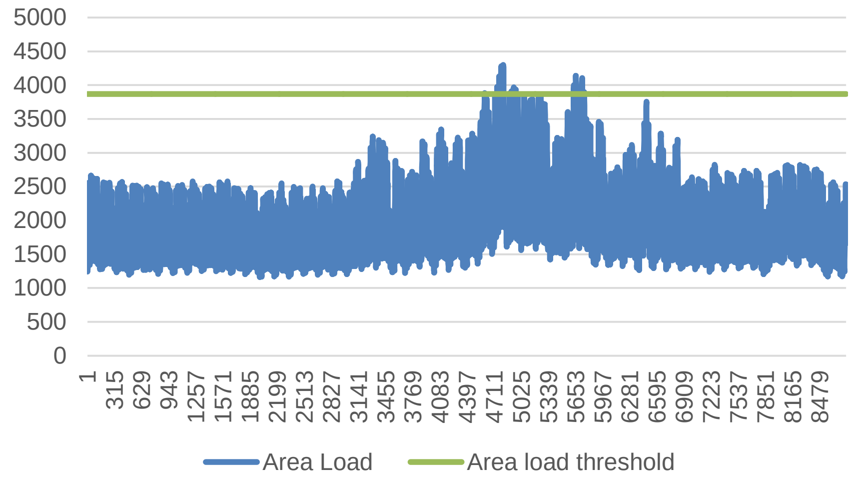
Study Steps – Method 1 (Step 1 by PTOs)

1. Get hourly forecast load data for the LCR area or sub-area under consideration
2. Calculate forecast area peak load minus initial slow response resource amount (existing slow response DR amount)
3. Using a spreadsheet, identify instances where the forecast hourly load for the area exceeds the level obtained in step 2. Record relevant data.
4. Repeat steps 2-3 for the various use limited, slow response resource amounts to be evaluated
5. Repeat steps 2-4 for each LCA and sub area to be assessed



Study Steps – Method 2 (Step 2 by ISO)

1. Get hourly forecast load data for the LCR area or sub-area under consideration
2. Starting from the marginal 2017 LCR base case reduce online generation in the LCR area by the initial amount of slow response resource (existing slow response DR amount)
3. Apply the limiting contingency, which should cause loading, voltage, etc. violation
4. Reduce area load proportionally until the loading, voltage, etc. is acceptable. Record the resulting area load
5. Using a spreadsheet, identify instances where the forecast hourly load exceeds the level obtained in step 4. Record relevant data.
6. Repeat steps 2-5 for the various use-limited, slow-response resource levels to be evaluated
7. Repeat steps 2-6 for each LCR area and sub area to be assessed



Characteristics of Slow Response Local Capacity Resources Special Study

Preliminary Results – Method 1 (Step 1)

Joint IOU Presentation

October 3, 2016

Slow-response Demand Response to Meet Local Capacity Needs

IOU Methodology and Results

CAISO/CPUC Joint Workshop

October 3, 2016

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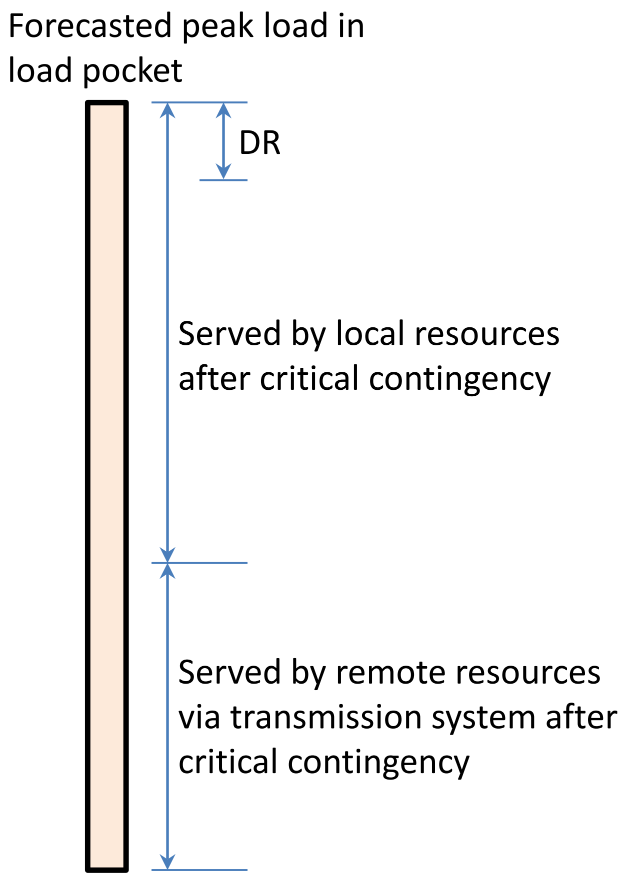
CAISO Local Capacity Requirements (LCR) Technical Analysis

Objective: identify specific CAISO areas that have limited import capability & determine minimum local resources (MW) necessary to mitigate reliability problems

SCE LOCAL AREAS	2016 LCR (MW)	CONTINGENCY	VIOLATION
LA Basin	8,887	Lugo - Victorville 500kV & Sylmar - Gould 230kV (Cat C)	not specified
	7,576	Redondo Unit #7 & Sylmar - Gould 230kV (Cat B)	thermal overload
El Nido	508	La Fresa - Hinson 230kV & La Fresa - Redondo #1 & #2 230kV	voltage collapse
Western LA Basin	4,472	Serrano - Villa Park #2 230kV & Serrano - Lewis 230kV	thermal overload
West of Devers	488	San Bernardino - Etiwanda 230kV & San Bernardino - Vista 230kV	voltage collapse
Valley-Devers	1,722	Palo Verde - Colorado River 500kV & Valley SC - Serrano 500kV	thermal overload
Valley	n/a	Meeting Valley-Devers LCR sufficient to meet this area.	
Eastern LA Basin	n/a	Meeting West of Devers and Valley-Devers LCR sufficient to meet this area.	
Big Creek/Ventura	2,398	Lugo - Victorville 500kV & Sylmar - Pardee #1 or #2 230kV (Cat C)	thermal overload
	2,141	Ormond Beach Unit #2 & Sylmar - Pardee #1 or #2 230kV (Cat B)	thermal overload
Rector	492	Eastwood & Rector - Vestal 230kV	thermal overload
Vestal	739	Eastwood & Magunden - Vestal 230kV	thermal overload
S. Clara	247	Pardee - S. Clara 230kV & Moorpark - S. Clara #1 & 2 230kV	voltage collapse
Moorpark	462	Pardee - Moorpark #1 230kV & Pardee - Moorpark #2 & #3 230kV	voltage collapse

Base Assumptions

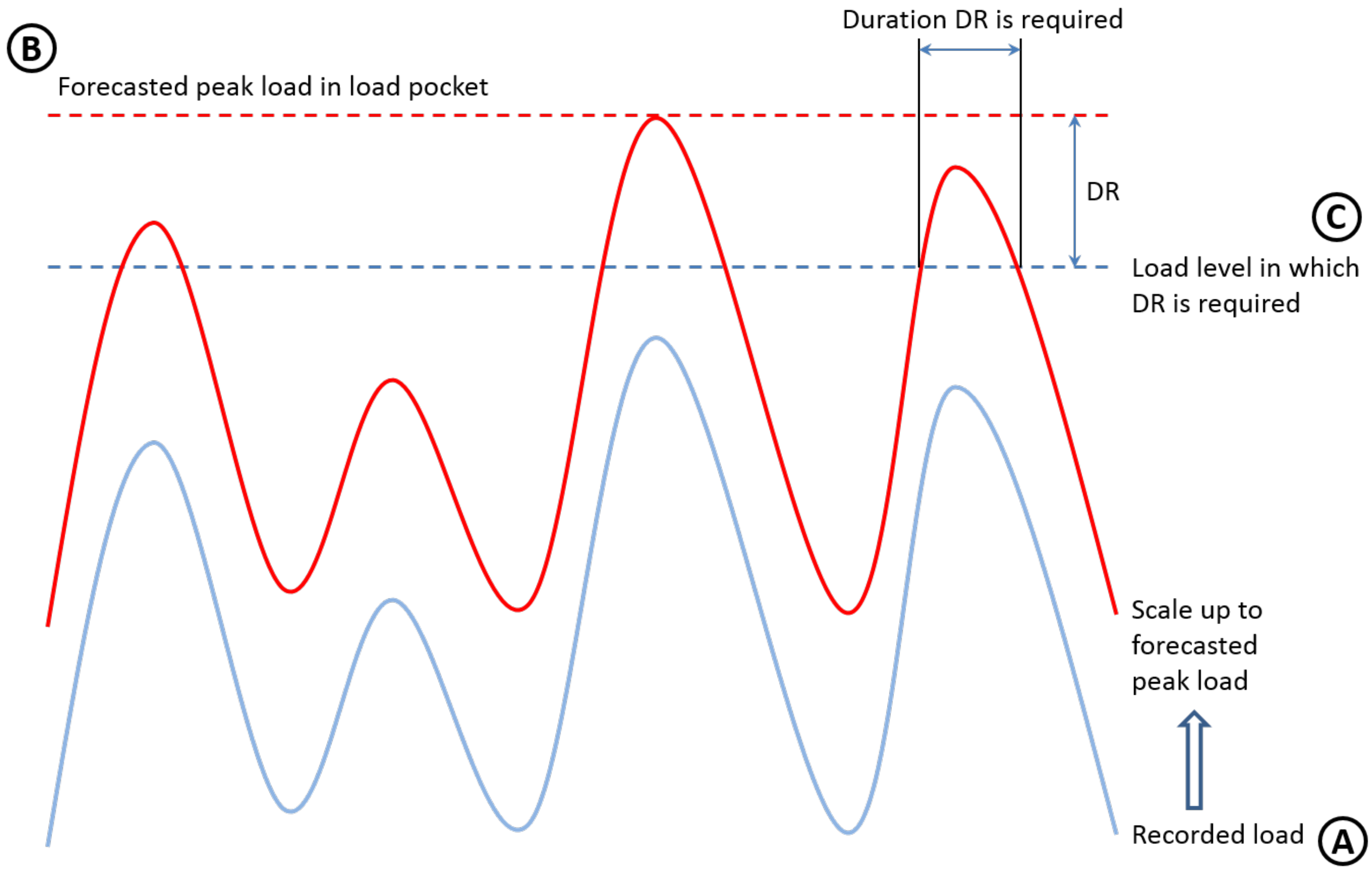
- Probability of peak load forecast, contingency type (e.g. N-1, N-1-1, N-1-2) and system performance violation fully incorporated into CAISO's analysis
- Local RA showing assumes peak load and contingency will occur and sufficient LCR resources must be available during peak load
- Assume sufficient resources to meet LCR and that DR is last to be used with pre-dispatch DR first type to be utilized



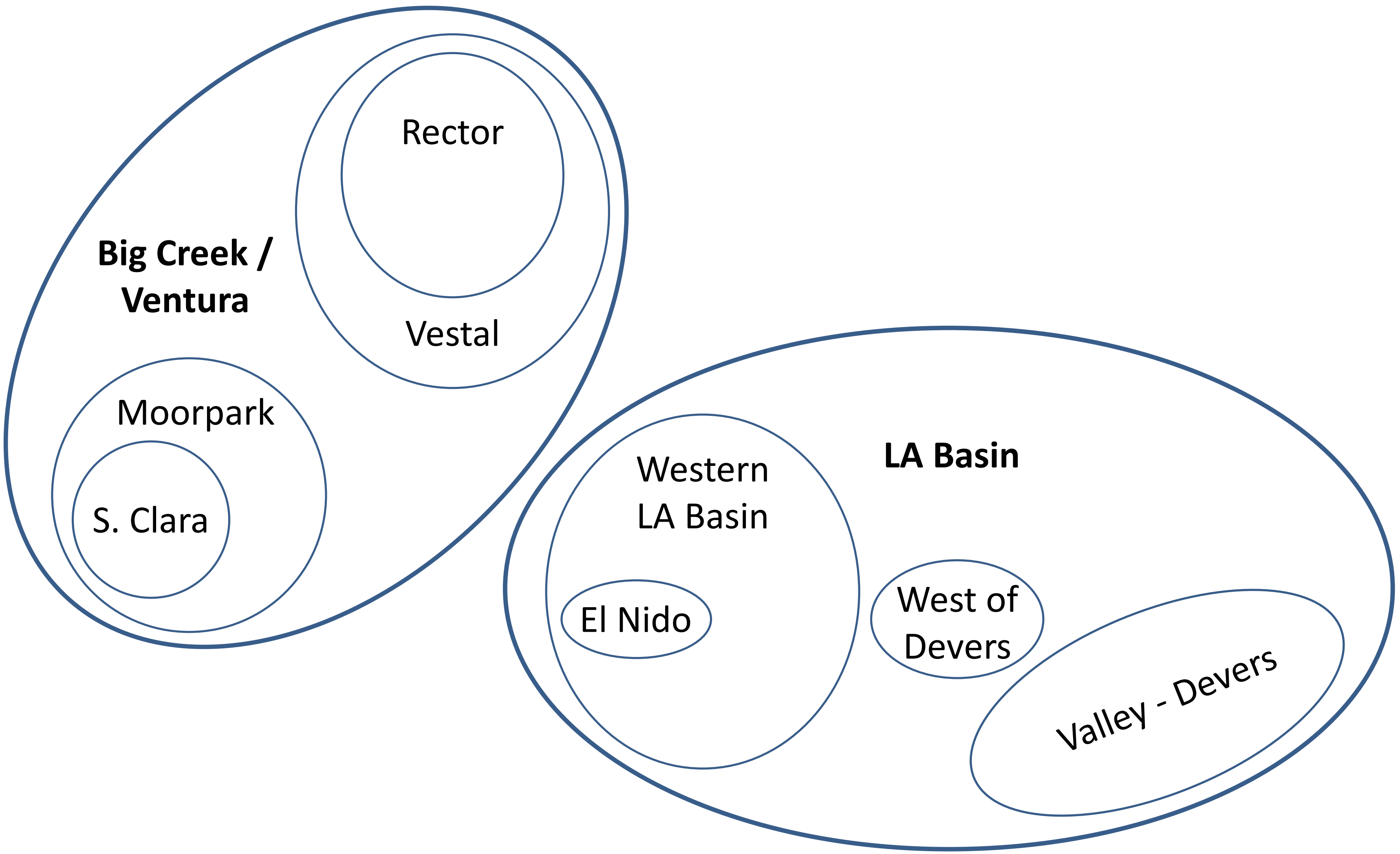
Analysis Steps

1. Get recorded hourly load for 2011 - 2015 (most recent five years) at all substations with LCR area
2. Scale recorded load curve up to forecasted load and examine peak periods
3. Examine different DR levels to determine number of calls and durations required (calls in larger area counted toward sub areas)

How the Analysis Is Performed



Southern California Edison (SCE) LCR Areas



Adjustment for Non-Coincident Calls Among Overlapping Areas (SCE)

- A resource located in a sub-area can be called due to need in the sub-area or in the overlapping LCA and sub-areas
- Non-coincident calls in overlapping areas are included in the sub-area results where applicable

Resource location	Areas resource can be called for
El Nido	El Nido, Western LA, LA Basin
West of Devers	West of Devers, LA Basin
Valley-Devers	Valley-Devers, LA Basin
Western LA	Western LA, LA Basin
LA Basin	LA Basin

Resource Location	Areas DR can be called for
Rector	Rector, Vestal, Big Creek Ventura
Vestal	Vestal, Big Creek-Ventura
Santa Clara	Santa Clara, Moorpark, Big Creek-Ventura
Moorpark	Moorpark, Big Creek-Ventura
Big Creek - Ventura	Big Creek-Ventura

SCE Existing DR with >20 min Response Time

Program name	Max annual hours	Max event days per month	Max event hours per month	Max event duration in hours	Max events per day	Additional restrictions	MW Capacity
BIP-30	180	10	N/A	6	1	N/A	516
CBP	N/A	N/A	30	4,6,8	1	Monday-Friday, 11 a.m. - 7 p.m.	86
AMP	N/A (varies by contract)						45

Program name	Level of Dispatch	Notification Time	Triggers
BIP-30	System-wide, SubLap, A-Bank	30 minutes	System, local, distribution reliability
CBP	System-wide, SubLap	Day Of: 1 hour, Day Ahead by 3 p.m.	Economic criterion (15,000 Btu/kWh heat rate)
AMP		Day of: 1 hour	varies by contract

SCE Slow-Response Resource Amounts Assessed (MW)

Area	Existing Slow DR	2% of Peak	5% of Peak	10% of Peak
El Nido	34.3 (2.1%)	33.2	83.0	165.9
West of Devers	9.4 (1.3%)	14.4	36.0	72.0
Valley-Devers	18.8 (0.7%)	52.7	131.8	263.6
Western LA Basin	354.9 (3.1%)	230.0	575.1	1150.1
LA Basin	566.7 (3.0%)	374.9	937.3	1874.6
Rector	16.6 (1.5%)	21.9	54.7	109.4
Vestal	27.7 (2.2%)	25.7	64.2	128.3
Santa Clara	30.1 (3.7%)	16.3	40.7	81.4
Moorpark	37.5 (2.3%)	32.0	80.1	160.1
Big Creek Ventura	79.7 (1.8%)	86.0	215.0	429.9
Total	646.4	460.9	1152.3	2304.5

Percentage values are in proportion to respective area 2017 forecast 1-in-10 peak load

SCE Total Annual Event Hours (3-Year Average)

	2% of Peak		5% of Peak		10% of Peak		Existing DR	
	Local	Overall	Local	Overall	Local	Overall	Local	Overall
El Nido	10	13	29	33	117	121	10	17
West of Devers	3	6	13	20	44	60	3	7
Valley-Devers	4	7	11	20	36	58	2	7
Western LA Basin	4	6	15	18	38	42	9	11
LA Basin	4	4	12	12	34	34	6	6
Rector	5	17	19	54	74	148	4	15
Vestal	5	15	24	51	85	145	5	14
Santa Clara	7	18	21	42	78	131	14	21
Moorpark	4	13	12	32	32	93	4	12
Big Creek Ventura	10	10	29	29	86	86	9	9

BIP-30 availability ≤ 180 hours/year

SCE Event Hours per Month (3-Year Average)

	2% of Peak		5% of Peak		10% of Peak		Existing DR	
	Local	Overall	Local	Overall	Local	Overall	Local	Overall
El Nido	9	12	23	26	48	49	9	14
West of Devers	3	4	8	12	24	32	3	6
Valley-Devers	4	5	7	13	20	31	2	6
Western LA Basin	4	6	13	15	26	28	8	9
LA Basin	4	4	11	11	24	24	6	6
Rector	5	8	13	22	43	62	4	7
Vestal	4	6	15	20	48	60	4	6
Santa Clara	5	8	14	16	35	41	9	10
Moorpark	3	6	9	14	22	35	3	5
Big Creek Ventura	5	5	12	12	35	35	4	4

CPB Availability ≤ 30 hours/month

SCE Event Days per Month (3-Year Average)

	2% of Peak		5% of Peak		10% of Peak		Existing DR	
	Local	Overall	Local	Overall	Local	Overall	Local	Overall
El Nido	2	3	3	4	8	9	2	3
West of Devers	2	2	3	4	7	8	2	2
Valley-Devers	2	2	3	4	5	7	2	3
Western LA Basin	2	2	3	4	4	5	3	3
LA Basin	2	2	3	3	5	5	2	2
Rector	1	3	4	6	9	12	1	3
Vestal	1	3	5	6	10	12	1	3
Santa Clara	2	3	3	3	5	9	3	3
Moorpark	1	2	3	3	4	9	1	2
Big Creek Ventura	2	2	3	3	9	9	2	2

BIP-30 availability ≤ 10 events/month

SCE Max Event Duration in Hours (3-Year Average)

	2% of Peak		5% of Peak		10% of Peak		Existing DR	
	Local	Overall	Local	Overall	Local	Overall	Local	Overall
El Nido	5	5	8	8	12	12	5	6
West of Devers	2	2	4	5	6	8	2	3
Valley-Devers	2	3	4	4	6	8	1	3
Western LA Basin	3	3	5	5	9	9	4	4
LA Basin	2	2	4	4	8	8	3	3
Rector	4	4	5	6	8	8	3	3
Vestal	3	3	6	6	8	8	3	3
Santa Clara	3	4	6	7	11	11	5	5
Moorpark	3	3	5	5	8	9	3	3
Big Creek Ventura	3	3	5	5	8	8	3	3

BIP-30 ≤ 6 hours/event; CPB ≤ 4,6 or 8 hours/event

Recommendations

- Using the average methodology rather than maximum
  - Using maximum tends to exacerbate the expected calls
  - Using average more closely corresponds to a 1-in-10 planning standard
- Developing one system wide recommendation for ease of implementation
  - Alternative option is to have area specific recommendations
- Setting a % limit for slow-response DR to count
  - In SCE case, 5% DR level meets “sufficient energy” criteria
  - Going above a general limit would be subject to an area specific study
  - Longer term: defining an operating profile definition for all “slow-response” resources to meet Local RA needs (i.e. beyond DR)
- Update annually as the area load shapes may change
  - E.g. El Nido 2010 and 2011 load shape compared to today
- Work on improving methodology
  - E.g. better load forecasting / scaling methodologies that are more accurate than simply scaling every point

Note: these are planning level recommendations; they need to be bridged with operational issues (e.g. how/when would DR be pre-dispatched)

Operational Challenges

- When would the “pre-dispatch resources” be dispatched?
  - Dispatching in Day-Ahead Market would likely result in a higher number of dispatches
  - Dispatching in Real-Time Market may need new CAISO processes (e.g. consideration of MOC constraints) and
- How often would the resource be pre-dispatched?
  - Planning study numbers assume “perfect forecast”, real-life operations may require a safety factor (i.e. more hours)
  - Frequency of dispatch would also depend on timing (DA vs RT)
- How would pre-dispatch work with existing programs
  - Programs like BIP-30 require a CAISO contingency as a condition for dispatch
  - Existing DR programs / tariffs may need to be updated
  - Dispatching BIP for more than 2-3 times per year will have a significant negative impact on enrollment
- Is there a need to update the CAISO processes and procedures?
  - E.g. how and when RDRR resources are dispatched

These issues should be addressed in time for the 2018 IOU DR Applications! (Especially if existing programs / tariffs need to be modified.)

Pacific Gas and Electric Company (PG&E)

Results

Existing Sublap DR programs Identified by PG&E with >20 min Response Time

Program name	Notification time	Max annual hours	Period	Max monthly event days	Days	Max monthly hours	Hours of the day	Max event hours	Capacity MW
BIP	30 m	180	any	10	any	N/A	any	N/A	63.9
AMP	30 m	80	5/1-10/31	N/A	M-F	N/A	11:00 19:00	4-6	71.4
Smart AC	N/A	100	5/1-10/31	N/A	any	N/A	any	6	44.9

PG&E Slow-Response Resource Amounts Assessed (MW)

Area	Existing DR	2% of Peak	5% of Peak	10% of Peak
Humboldt	6.8	2.8	7.1	14.2
Sierra	18.5	23.9	59.6	119.2
Stockton	22.0	26.9	67.3	134.6
Greater Bay	48.5	163.5	408.8	817.7
N Coast & N Bay	9.6	28.3	70.7	141.5
Kern	42.4	36.6	91.6	183.2
Fresno	32.3	65.1	162.7	325.4
Total	180.2	347.1	867.8	1735.7

Humboldt (3-Year Max. Numbers)

Parameter	Existing DR	2% of Peak	5% of Peak	10% of Peak
Yearly # of hours	20	4	22	149
Monthly # of hours	10	4	11	62
Monthly event days	6	2	6	19
Weekend Events	0	0	1	7
Events outside 11-7	2	1	2	9
Days in a row	4	2	4	13
Other	Need is November-March only	Need is November-March only	Need is November-March only	2 events/day or 8 hours/day with 6 hours break

Sierra (3-Year Max. Numbers)

Parameter	Existing DR	2% of Peak	5% of Peak	10% of Peak
Yearly # of hours	3	4	10	32
Monthly # of hours	3	4	9	22
Monthly event days	2	2	3	5
Weekend Events	0	0	1	3
Events outside 11-7	0	0	0	0
Days in a row	2	2	3	6
Other	-	-	-	6 hours/day

Stockton (3-Year Max. Numbers)

Parameter	Existing DR	2% of Peak	5% of Peak	10% of Peak
Yearly # of hours	6	6	18	49
Monthly # of hours	4	5	11	20
Monthly event days	1	1	3	4
Weekend Events	0	0	0	1
Events outside 11-7	0	0	0	0
Days in a row	1	1	3	3
Other	-	5 hours/day	6 hours/day	7 hours/day

Bay Area (3-Year Max. Numbers)

Parameter	Existing DR	2% of Peak	5% of Peak	10% of Peak
Yearly # of hours	2	5	18	50
Monthly # of hours	2	4	15	29
Monthly event days	2	2	4	6
Weekend Events	1	1	1	2
Events outside 11-7	0	0	0	0
Days in a row	2	2	3	4
Other	-	-	5 hours/day	8 hours/day

N Cost & N Bay (3-Year Max. Numbers)

Parameter	Existing DR	2% of Peak	5% of Peak	10% of Peak
Yearly # of hours	2	2	14	50
Monthly # of hours	2	2	8	20
Monthly event days	1	1	3	5
Weekend Events	0	0	2	2
Events outside 11-7	0	0	0	0
Days in a row	1	1	2	6
Other	-	-	-	6 hours/day

Kern (3-Year Max. Numbers)

Parameter	Existing DR	2% of Peak	5% of Peak	10% of Peak
Yearly # of hours	12	8	46	175
Monthly # of hours	8	7	34	110
Monthly event days	5	3	8	20
Weekend Events	0	0	2	10
Events outside 11-7	1	0	2	2
Days in a row	3	1	3	9
Other	-	-	8 hours/day	11 hours/day

Fresno (3-Year Max. Numbers)

Parameter	Existing DR	2% of Peak	5% of Peak	10% of Peak
Yearly # of hours	11	14	37	133
Monthly # of hours	8	11	26	79
Monthly event days	3	4	7	14
Weekend Events	0	0	3	8
Events outside 11-7	0	0	0	0
Days in a row	2	2	4	8
Other	-	-	7 hours/day	9 hours/day

San Diego Gas & Electric (SDG&E)

Methodology and Results

Load Shapes and LCR

1. San Diego chose Area Loads by hour because of challenges of predicting DR location's participation within a well-defined LCR area sub area (like Mission or Encina)
2. DR effectiveness conceived of as a reduction in LCR area peak rather than as a physical substitute for quick start generation capacity
3. FERC Form 714 used since it is vetted and public and characterized the LCR area of interest. This data is extracted from meters in many locations within the SDG&E grid and is cleaned and aggregated then checked against other information sources for reasonableness and posted at FERC.

Study

- SDG&E modeled a load profile for 2017 using recent historical data with a 1 in 10 multiplier from the CEC IEPR.
- SDG&E estimated the potential for using DR at its nominal 10 MW, and 1% and 3% of peak levels.

Results (Method One)

Forecast 2017 from

2015

Slow Response DR **Pre dispatch calls needed**

Amount MW	Amount as % Peak	Days	Hours	Max Duration
10.00	0.2%	1	1	1
48.38	1.0%	1	2	2
145.14	3.0%	2	9	5

2014

Amount MW	Amount as % Peak	Days	Hours	Max Duration
10.00	0.2%	1	1	1
48.38	1.0%	1	2	2
145.14	3.0%	2	4	2

2013

Amount MW	Amount as % Peak	Days	Hours	Max Duration
total hours	0.2%	1	1	1
48.38	1.0%	2	4	2
145.14	3.0%	3	9	4

Appendix

SCE total annual event hours (3-year max)

	Existing DR		2% of Peak		5% of Peak		10% of Peak	
	Local	Overall	Local	Overall	Local	Overall	Local	Overall
El Nido	19	29	19	22	45	47	223	223
West of Devers	4	9	5	6	18	23	65	83
Valley-Devers	3	9	8	11	15	26	57	79
Western LA Basin	16	16	7	7	23	23	49	52
LA Basin	8	8	5	5	13	13	40	40
Rector	5	27	7	28	22	75	88	190
Vestal	6	27	6	28	31	73	100	189
Santa Clara	21	26	13	26	26	65	86	184
Moorpark	6	23	6	24	19	61	37	146
Big Creek Ventura	21	21	22	22	57	57	141	141

- BIP-30 ≤ 180 hours/year

SCE number of event hours per month (3-year max)

	Existing DR		2% of Peak		5% of Peak		10% of Peak	
	Local	Overall	Local	Overall	Local	Overall	Local	Overall
El Nido	16	23	16	19	36	37	63	63
West of Devers	4	9	4	5	12	13	31	37
Valley-Devers	3	8	8	8	14	16	29	33
Western LA Basin	13	13	7	7	17	17	31	33
LA Basin	8	8	5	5	12	12	26	26
Rector	5	9	7	11	14	28	52	81
Vestal	6	8	6	8	21	25	64	76
Santa Clara	13	13	9	10	17	21	42	50
Moorpark	3	8	3	8	13	20	24	47
Big Creek Ventura	7	7	7	7	20	20	46	46

- CPB ≤ 30 hours/month

SCE number of event days per month (3-year max)

	Existing DR		2% of Peak		5% of Peak		10% of Peak	
	Local	Overall	Local	Overall	Local	Overall	Local	Overall
El Nido	4	4	3	4	4	4	14	14
West of Devers	2	3	2	3	6	6	9	11
Valley-Devers	3	4	3	3	5	6	7	8
Western LA Basin	4	4	3	3	4	4	4	5
LA Basin	3	3	2	2	4	4	5	5
Rector	2	4	2	4	6	7	11	16
Vestal	2	3	2	3	7	7	13	16
Santa Clara	3	3	3	3	4	4	6	12
Moorpark	2	3	2	3	4	4	4	12
Big Creek Ventura	3	3	3	3	4	4	12	12

- BIP-30 ≤ 10 events/month

SCE max event duration in hours (3-year max)

	Existing		2% of Peak		5% of Peak		10% of Peak	
	Local	Overall	Local	Overall	Local	Overall	Local	Overall
El Nido	6	7	6	6	11	11	14	14
West of Devers	2	4	2	3	4	5	7	9
Valley-Devers	1	4	3	3	4	5	7	9
Western LA Basin	4	4	3	3	5	5	10	10
LA Basin	4	4	3	3	5	5	9	9
Rector	3	4	4	4	6	6	9	9
Vestal	4	4	4	4	6	6	9	9
Santa Clara	5	5	4	4	6	7	11	11
Moorpark	3	4	3	4	5	6	9	9
Big Creek Ventura	4	4	4	4	6	6	9	9

- BIP-30 ≤ 6 hours/event, CPB ≤ 4,6 or 8 hours/event

Characteristics of Slow Response Local Capacity Resources Special Study

ISO Preliminary Results

Nebiyu Yimer, Regional Transmission Engineer Lead
Catalin Micsa, Sr. Advisor Regional Transmission Engineer

October 3, 2016

Southern California Area Results
(SCE and SDG&E)
Nebiyu Yimer

Adjustment for non-coincident calls among overlapping areas

- A resource located in a sub-area can be called due to need in the sub-area or overlapping LCA and sub-areas
- Non-coincident calls in overlapping areas must be included in the sub-area results where applicable

Resource location	Areas resource can be called for
El Nido	El Nido, Western LA, LA Basin
West of Devers	West of Devers, LA Basin
Valley-Devers	Valley-Devers, LA Basin
Western LA	Western LA, LA Basin
LA Basin	LA Basin

Resource Location	Areas DR can be called for
Rector	Rector, Vestal, Big Creek Ventura
Vestal	Vestal, Big Creek-Ventura
Santa Clara	Santa Clara, Moorpark, Big Creek-Ventura
Moorpark	Moorpark, Big Creek-Ventura
Big Creek - Ventura	Big Creek-Ventura

SCE existing DR with >20 min response time

Program name	Max annual hours	Max event days per month	Max event hours per month	Max event duration in hours	Max events per day	Additional restrictions	MW Capacity
BIP-30	180	10	N/A	6	1	N/A	516
CBP	N/A	N/A	30	4,6,8	1	Monday-Friday, 11 a.m. - 7 p.m.	86
AMP	N/A (varies by contract)						45

Program name	Level of Dispatch	Notification Time	Triggers
BIP-30	System-wide, SubLap, A-Bank	30 minutes	System, local, distribution reliability
CBP	System-wide, SubLap	Day Of: 1 hour, Day Ahead by 3 p.m.	Economic criterion (15,000 Btu/kWh heat rate)
AMP		Day of: 1 hour	varies by contract

SCE slow-response resource amounts assessed, MW

Area	Existing Slow DR	2% of Peak	5% of Peak	10% of Peak
El Nido	34.3 (2.1%)	33.2	83.0	165.9
West of Devers	9.4 (1.3%)	14.4	36.0	72.0
Valley-Devers	18.8 (0.7%)	52.7	131.8	263.6
Western LA Basin	354.9 (3.1%)	230.0	575.1	1150.1
LA Basin	566.7 (3.0%)	374.9	937.3	1874.6
Rector	16.6 (1.5%)	21.9	54.7	109.4
Vestal	27.7 (2.2%	25.7	64.2	128.3
Santa Clara	30.1 (3.7%)	16.3	40.7	81.4
Moorpark	37.5 (2.3%)	32.0	80.1	160.1
Big Creek Ventura	79.7 (1.8%)	86.0	215.0	429.9
Total	646.4	460.9	1152.3	2304.5

- Percentage values are in proportion to respective area 2017 peak load

Method 1 & 2 load thresholds for existing slow DR

Area	Area load MW (A)	Method 1		Method 2	
		Existing Slow DR MW (B)	Area load threshold (A-B)	Required load reduction from power flow (C)	Area load threshold (A-C)
El Nido *	1,659	34.3	1,625	34.3	1,625
West of Devers *	720	9.4	711	9.4	711
Valley-Devers	2,636	18.8	2,617	N/A	N/A
Western LA Basin	11,501	354.9	11,146	N/A	N/A
LA Basin	18,746	566.7	18,179	N/A	N/A
San Diego	4,838	10	4,828	N/A	N/A
Combined LA Basin/San Diego *	23,584	577.7	N/A	1,085	22,499
Rector	1,094	16.6	1,077	N/A	N/A
Vestal	1,283	27.7	1,255	N/A	N/A
Santa Clara *	814	30.1	784	34.9	779
Moorpark *	1,601	37.5	1,564	38.6	1562
Big Creek Ventura*	4,299	79.7	4,219	79.7	4219

* Areas further assessed using Method 2.

SCE total annual event hours (3-year max.)

	Existing DR*		2% of Peak		5% of Peak		10% of Peak	
	Local	Overall	Local	Overall	Local	Overall	Local	Overall
El Nido*	19	29(30)	19	22	45	47	223	223
West of Devers *	4	9 (13)	5	6	18	23	65	83
Valley-Devers	3	9 (14)	8	11	15	26	57	79
Western LA Basin	16	16(17)	7	7	23	23	49	52
LA Basin*	8(13)	8(13)	5	5	13	13	40	40
Rector	5	27	7	28	22	75	88	190
Vestal	6	27	6	28	31	73	100	189
Santa Clara*	21(24)	26(29)	13	26	26	65	86	184
Moorpark*	6(7)	23	6	24	19	61	37	146
Big Creek Ventura*	21	21	22	22	57	57	141	141

* Areas and resource levels further assessed using Method 2. Results are provided in parenthesis where different. Method 2 assessment for LA Basin is based on the combined LA Basin-San Diego LCA.

- BIP-30 ≤ 180 hours/year

SCE number of event hours per month (3-year max.)

	Existing DR*		2% of Peak		5% of Peak		10% of Peak	
	Local	Overall	Local	Overall	Local	Overall	Local	Overall
El Nido*	16	23(24)	16	19	36	37	63	63
West of Devers*	4	9(12)	4	5	12	13	31	37
Valley-Devers	3	8(12)	8	8	14	16	29	33
Western LA Basin	13	13(14)	7	7	17	17	31	33
LA Basin*	8(12)	8(12)	5	5	12	12	26	26
Rector	5	9	7	11	14	28	52	81
Vestal	6	8	6	8	21	25	64	76
Santa Clara*	13 (14)	13(14)	9	10	17	21	42	50
Moorpark*	3 (4)	8(8)	3	8	13	20	24	47
Big Creek Ventura*	7	7	7	7	20	20	46	46

* Areas and resource levels further assessed using Method 2. Results are provided in parenthesis where different. Method 2 assessment for LA Basin is based on the combined LA Basin-San Diego LCA.

- CPB ≤ 30 hours/month

SCE number of event days per month (3-year max.)

	Existing DR*		2% of Peak		5% of Peak		10% of Peak	
	Local	Overall	Local	Overall	Local	Overall	Local	Overall
El Nido*	4	4	3	4	4	4	14	14
West of Devers*	2	3	2	3	6	6	9	11
Valley-Devers	3	4	3	3	5	6	7	8
Western LA Basin	4	4	3	3	4	4	4	5
LA Basin*	3	3	2	2	4	4	5	5
Rector	2	4	2	4	6	7	11	16
Vestal	2	3	2	3	7	7	13	16
Santa Clara*	3	3	3	3	4	4	6	12
Moorpark*	2(3)	3	2	3	4	4	4	12
Big Creek Ventura*	3	3	3	3	4	4	12	12

* Areas and resource levels further assessed using Method 2. Results are provided in parenthesis where different. Method 2 assessment for LA Basin is based on the combined LA Basin-San Diego LCA.

- BIP-30 ≤ 10 events/month

SCE max event duration in hours (3-year max.)

	Existing*		2% of Peak		5% of Peak		10% of Peak	
	Local	Overall	Local	Overall	Local	Overall	Local	Overall
El Nido*	6	7	6	6	11	11	14	14
West of Devers*	2	4(5)	2	3	4	5	7	9
Valley-Devers	1	4(5)	3	3	4	5	7	9
Western LA Basin	4	4(5)	3	3	5	5	10	10
LA Basin*	4(5)	4(5)	3	3	5	5	9	9
Rector	3	4	4	4	6	6	9	9
Vestal	4	4	4	4	6	6	9	9
Santa Clara*	5	5	4	4	6	7	11	11
Moorpark*	3	4	3	4	5	6	9	9
Big Creek Ventura*	4	4	4	4	6	6	9	9

* Areas and resource levels further assessed using Method 2. Results are provided in parenthesis where different. Method 2 assessment for LA Basin is based on the combined LA Basin-San Diego LCA.

- BIP-30 ≤ 6 hours/event, CPB ≤ 4,6 or 8 hours/event

SCE annual number of weekend events (3-year max.)

	Existing*		2% of Peak		5% of Peak		10% of Peak	
	Local	Overall	Local	Overall	Local	Overall	Local	Overall
El Nido*	0	0	0	0	0	0	1	1
West of Devers*	0	0	0	0	2	2	2	2
Valley-Devers	2	2	2	2	2	2	4	4
Western LA Basin	0	0	0	0	0	0	0	1
LA Basin*	0	0	0	0	0	0	1	1
Rector	0	1	0	1	0	2	3	5
Vestal	0	1	0	1	0	2	3	5
Santa Clara*	1	1	1	1	1	2	1	4
Moorpark*	0	1	0	1	0	2	0	4
Big Creek Ventura*	1	1	1	1	2	2	4	4

* Areas and resource levels further assessed using Method 2. Results are provided in parenthesis where different. Method 2 assessment for LA Basin is based on the combined LA Basin-San Diego LCA.

- CPB availability restricted to weekdays Monday-Friday

SCE annual number of weekday event hours outside 11 a.m. – 7 p.m. (3-year max.)

	Existing*		2% of Peak		5% of Peak		10% of Peak	
	Local	Overall	Local	Overall	Local	Overall	Local	Overall
El Nido*	2	2	2	2	10	10	46	46
West of Devers*	0	0	0	0	0	0	0	0
Valley-Devers	0	0	0	0	0	0	0	0
Western LA Basin	0	0	0	0	0	0	1	1
LA Basin*	0	0	0	0	0	0	0	0
Rector	0	0	0	0	1	1	5	8
Vestal	0	0	0	0	1	1	8	8
Santa Clara*	0	0	0	0	0	0	10	12
Moorpark*	0	0	0	0	0	0	0	2
Big Creek Ventura*	0	0	0	0	0	0	2	2

* Areas and resource levels further assessed using Method 2. Results are provided in parenthesis where different. Method 2 assessment for LA Basin is based on the combined LA Basin-San Diego LCA.

- CPB availability restricted to weekdays 11 a.m. - 7 p.m.

SCE number of events > 1 per day (3-year max.)

	Existing*		2% of Peak		5% of Peak		10% of Peak	
	Local	Overall	Local	Overall	Local	Overall	Local	Overall
El Nido*	0	0	0	0	2	2	6	6
West of Devers*	0	0	0	0	1	0	0	0
Valley-Devers	0	0	0	0	0	0	1	0
Western LA Basin	0	0	0	0	0	0	3	1
LA Basin*	0	0	0	0	0	0	0	0
Rector	1	0	0	0	1	0	1	2
Vestal	0	0	0	0	0	0	2	2
Santa Clara*	0	0	0	0	1	1	4	1
Moorpark*	0	0	0	0	0	0	1	0
Big Creek Ventura*	0	0	0	0	0	0	0	0

* Areas and resource levels further assessed using Method 2. Results are provided in parenthesis where different. Method 2 assessment for LA Basin is based on the combined LA Basin-San Diego LCA.

- BIP-30, CPB maximum events per day ≤ 1

SDGE San Diego area assessment (3-year max.)

SDG&E existing DR with >20 min response time

program name	Max annual hours	Max event days per month	Max event hours per month	Max event duration in hours	Max events per day	Max consec. event days	Additional restrictions	MW Capacity
Summer Saver	72	18	72	4	1	3	May – October	10

Slow resource amounts assessed, MW

LCR Area	Existing Slow DR	1% of Peak	3% of Peak
San Diego area slow-resource amounts assessed	10.0	40.4	145.1

San Diego area results (3-year max.)

	Slow resource amounts		
	Existing DR*	1% of Peak	3% of Peak
Total annual event hours	1 (13)	4	9
Number of event hours per month	1(12)	2	9
Number of event days per month	1(3)	1	3
Max event duration in hours	1(5)	2	5
Number of events/day > 1	0	0	1
Max consecutive event days	1 (3)	1	3
Number of events during November - April	0	0	0

* Slow-response resource levels further assessed using Method 2. Results are provided in parenthesis. Method 2 assessment is based on the combined LA Basin-San Diego LCA

Observations

- The study results indicate existing slow-response DR resources may meet local RA needs at current DR levels except:
  - in the El Nido sub-area, which has a high load factor, DR resources that have less than 7 hour per event availability
  - in the combined LA Basin-San Diego LCA and all of its sub-areas and in the Santa Clara sub-area, DR resources that have less than 5 hour per event availability.
  - in the Big Creak Ventura LCA, all of its sub-areas, and Valley-Devers and El Nido sub-areas, DR resources that are restricted to weekdays or 11 a.m. to 7 p.m. weekdays.
- The above observations equally apply to fast-response DR resources. The specific characteristics could be more limiting if slow- and fast-response DR amounts were combined.

Observations – cont'd

- The SCE AMP program was not evaluated against the availability results as its characteristics were not shared with the ISO.

Northern California (PG&E) Area Results
Catalin Micsa

Existing Sublap DR programs Identified by PG&E with >20 min response time

Program name	Notification time	Max annual hours	Period	Max monthly event days	Days	Max monthly hours	Hours of the day	Max event hours	Capacity MW
BIP	30 m	180	any	10	any	N/A	any	N/A	63.9
AMP	30 m	80	5/1-10/31	N/A	M-F	N/A	11:00 19:00	4-6	71.4
Smart AC	N/A	100	5/1-10/31	N/A	any	N/A	any	6	44.9

PG&E slow-response resource amounts assessed, MW

Area	Existing DR	2% of Peak	5% of Peak	10% of Peak
Humboldt	6.8	2.8	7.1	14.2
Sierra	18.5	23.9	59.6	119.2
Stockton	22.0	26.9	67.3	134.6
Greater Bay	48.5	163.5	408.8	817.7
N Coast & N Bay	9.6	28.3	70.7	141.5
Kern	42.4	36.6	91.6	183.2
Fresno	32.3	65.1	162.7	325.4
Total	180.2	347.1	867.8	1735.7

Sierra, Stockton and Kern process book definitions (herein) do not align with local capacity area definitions.

Humboldt (3-year max. numbers)

Parameter	Existing DR	2% of Peak	5% of Peak	10% of Peak
Yearly # of hours	20	4	22	149
Monthly # of hours	10	4	11	62
Monthly event days	6	2	6	19
Weekend Events	0	0	1	7
Events outside 11-7	2	1	2	9
Days in a row	4	2	4	13
Other	Need is November-March only	Need is November-March only	Need is November-March only	2 events/day or 8 hours/day with 6 hours break

Result values do not take into account observed non-coincidence of DR calls among areas and sub areas.

Sierra (3-year max. numbers)

Parameter	Existing DR	2% of Peak	5% of Peak	10% of Peak
Yearly # of hours	3	4	10	32
Monthly # of hours	3	4	9	22
Monthly event days	2	2	3	5
Weekend Events	0	0	1	3
Events outside 11-7	0	0	0	0
Days in a row	2	2	3	6
Other	-	-	-	6 hours/day

Result values do not take into account observed non-coincidence of DR calls among areas and sub areas.

Stockton (3-year max. numbers)

Parameter	Existing DR	2% of Peak	5% of Peak	10% of Peak
Yearly # of hours	6	6	18	49
Monthly # of hours	4	5	11	20
Monthly event days	1	1	3	4
Weekend Events	0	0	0	1
Events outside 11-7	0	0	0	0
Days in a row	1	1	3	3
Other	-	5 hours/day	6 hours/day	7 hours/day

Result values do not take into account observed non-coincidence of DR calls among areas and sub areas.

Bay Area (3-year max. numbers)

Parameter	Existing DR	2% of Peak	5% of Peak	10% of Peak
Yearly # of hours	2	5	18	50
Monthly # of hours	2	4	15	29
Monthly event days	2	2	4	6
Weekend Events	1	1	1	2
Events outside 11-7	0	0	0	0
Days in a row	2	2	3	4
Other	-	-	5 hours/day	8 hours/day

Result values do not take into account observed non-coincidence of DR calls among areas and sub areas.

N Cost & N Bay (3-year max. numbers)

Parameter	Existing DR	2% of Peak	5% of Peak	10% of Peak
Yearly # of hours	2	2	14	50
Monthly # of hours	2	2	8	20
Monthly event days	1	1	3	5
Weekend Events	0	0	2	2
Events outside 11-7	0	0	0	0
Days in a row	1	1	2	6
Other	-	-	-	6 hours/day

Result values do not take into account observed non-coincidence of DR calls among areas and sub areas.

Kern (3-year max. numbers)

Parameter	Existing DR	2% of Peak	5% of Peak	10% of Peak
Yearly # of hours	12	8	46	175
Monthly # of hours	8	7	34	110
Monthly event days	5	3	8	20
Weekend Events	0	0	2	10
Events outside 11-7	1	0	2	2
Days in a row	3	1	3	9
Other	-	-	8 hours/day	11 hours/day

Result values do not take into account observed non-coincidence of DR calls among areas and sub areas.

Fresno (3-year max. numbers)

Parameter	Existing DR	2% of Peak	5% of Peak	10% of Peak
Yearly # of hours	11	14	37	133
Monthly # of hours	8	11	26	79
Monthly event days	3	4	7	14
Weekend Events	0	0	3	8
Events outside 11-7	0	0	0	0
Days in a row	2	2	4	8
Other	-	-	7 hours/day	9 hours/day

Result values do not take into account observed non-coincidence of DR calls among areas and sub areas.

Conclusions

Existing slow-response DR programs may be suitable for:

1. Overall constraints in:
   - North Coast/North Bay,
   - Fresno and
   - Bay Area
     - *Weekend event (eliminate programs with weekend exemption)*

They do not appear to be suitable for:

1. Humboldt - due to season, time and length of need
   - *With exception of BIP*
2. Overall constraints in Sierra, Stockton, Kern
   - *Due to definition mismatch, which would require correcting*
3. Any sub-area constraints
   - *Due to data limitations at this time PG&E did not study the use of slow-start DR to mitigate sub-area reliability issues. Future feasibility study required before implementation.*
4. Any deficient sub-areas
   - *Future feasibility study required before implementation. Potentially high numbers of events and hours projected.*

Other considerations regarding the study approach

- Availability requirements increase as the amount of DR (or other slow-response resources) counted for local RA increases.
  - The study results don't apply for increased levels of DR as local resource adequacy resources
- Study assumes critical N-1/N-1 contingencies are monitored in or close to real time in order to pre-dispatch slow-response resources exactly when needed.
  - How precisely can these needs be forecast and the resources dispatched?
- Historical hourly load profiles were used for this study, which may not capture future changes in load shape due to increasing DER such as BTM PV.

Next steps

Date	Milestone
Sept. 21 - 22, 2016	Present preliminary results to stakeholders
Oct. 3, 2016	ISO-CPUC slow-response DR joint workshop
Sept. 22 – Oct. 10, 2016	Stakeholder comments to be submitted to regionaltransmission@caiso.com
Oct. 11 – Nov. 11, 2016	Refine results based on comments
Nov. 16, 2016	Provide updates to stakeholders
Nov. 16 - 30, 2016	Stakeholder comments to be submitted to regionaltransmission@caiso.com
January 2017	ISO posts the draft transmission plan including the updated results of this special study

Process and Implementation Discussion

How we reflect final study results into business practices and DR resource/program designs

Moderator: Matthew Tisdale, CPUC

Proposed Process Overview

- Year 1 Goals and Tasks
- Year “n” Goals and Tasks Proposal

John Goodin, CAISO

Regulatory Policy Manager

Planning and Operations

TPP and RA Proceeding

Plan for right resources/right capabilities

Planning

Sets minimum local RA PDR availability requirements (may be more or less hours than RA program availability requirements).

The study will be part of the local capacity technical analysis and timeline, which is a core element of the TPP.

Resources procured and shown that meet study needs will be tested against local capacity needs to determine effectiveness of procurement and if deficiencies exist.

ISO Market

Manage & deliver when and where needed

Operations

Resources are available to, and committed by, the ISO when and where needed to ensure reliability.

Non- discriminatory bidding and market rules ensures optimal, least cost dispatch of all resource types.

PDR managed via bids and resource attributes. Bidding parameters include:

- Min load Cost
- Start-up Cost

} Plus opportunity costs if use-limited

- Energy Bid (unmitigated)

Proposed Process Year 1: Goals and Tasks

TPP:

- Vet and finalize slow response study in the TPP stakeholder initiative.
- Document study methodology to be used in TPP. Revise BPMs.
- Communicate and clarify final study results and findings in the TPP.

Joint Workshops:

- Clarify TPP results.
- Develop solutions to any implications or implementation issues.
- Document findings and solutions.
- Input findings and solutions into record of CPUC RA proceeding.

CPUC RA Proceeding:

- Vet slow response study results in the CPUC's RA proceeding.
- 2018 RA Compliance Year decision on slow response resources.

CAISO BPM Update:

- Incorporate solution and study process into BPM.

Proposed Process Year “n”: Goals and Tasks

- CAISO perform slow response study as part of local capacity technical analysis in the TPP.
- Vet study results in TPP stakeholder process.
- Finalize and publish study results in the local capacity technical analysis.
- Submit local capacity technical analysis, including slow response results to CPUC for review and procurement authorization.

Detailing and Documenting the Slow Response Local Capacity Study Process

Necessary changes detailing the final study process will be incorporated into the Reliability Requirements BPM.

Primary revisions/additions will likely be reflected in:

- Section 4: Resource Adequacy Capacity
  - Details Resource Adequacy requirements that Scheduling Coordinators for Load Serving Entities must meet- who, what, when, why.
- Section 8: Local Capacity and Reliability Procurement Provisions
  - Details the technical study conducted by the ISO to determine the minimum amount of capacity that must be available within Local Capacity Areas. Incorporate slow response study details into this section.

Implementation Detail

Operation of energy-limited, slow response resources

Dede Subakti

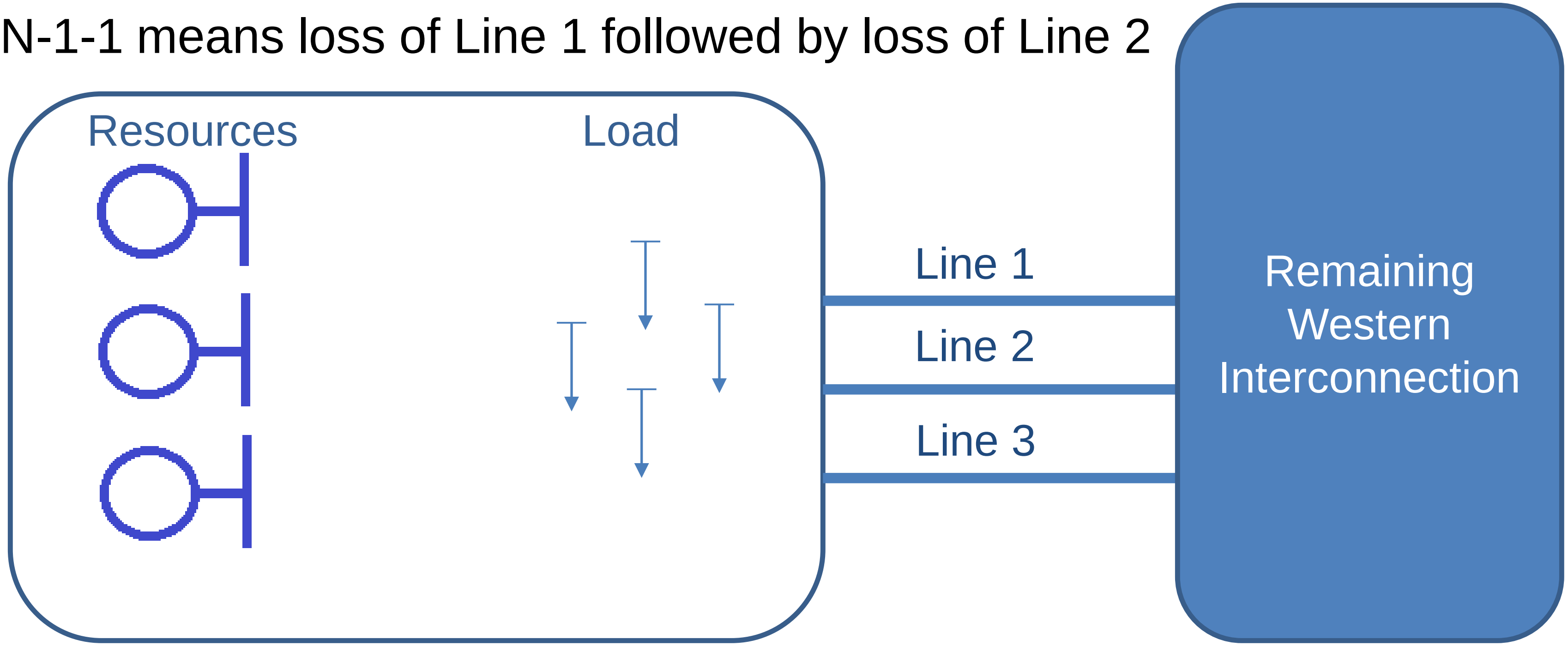
Director, Operations Engineering Services

Back to the Basic

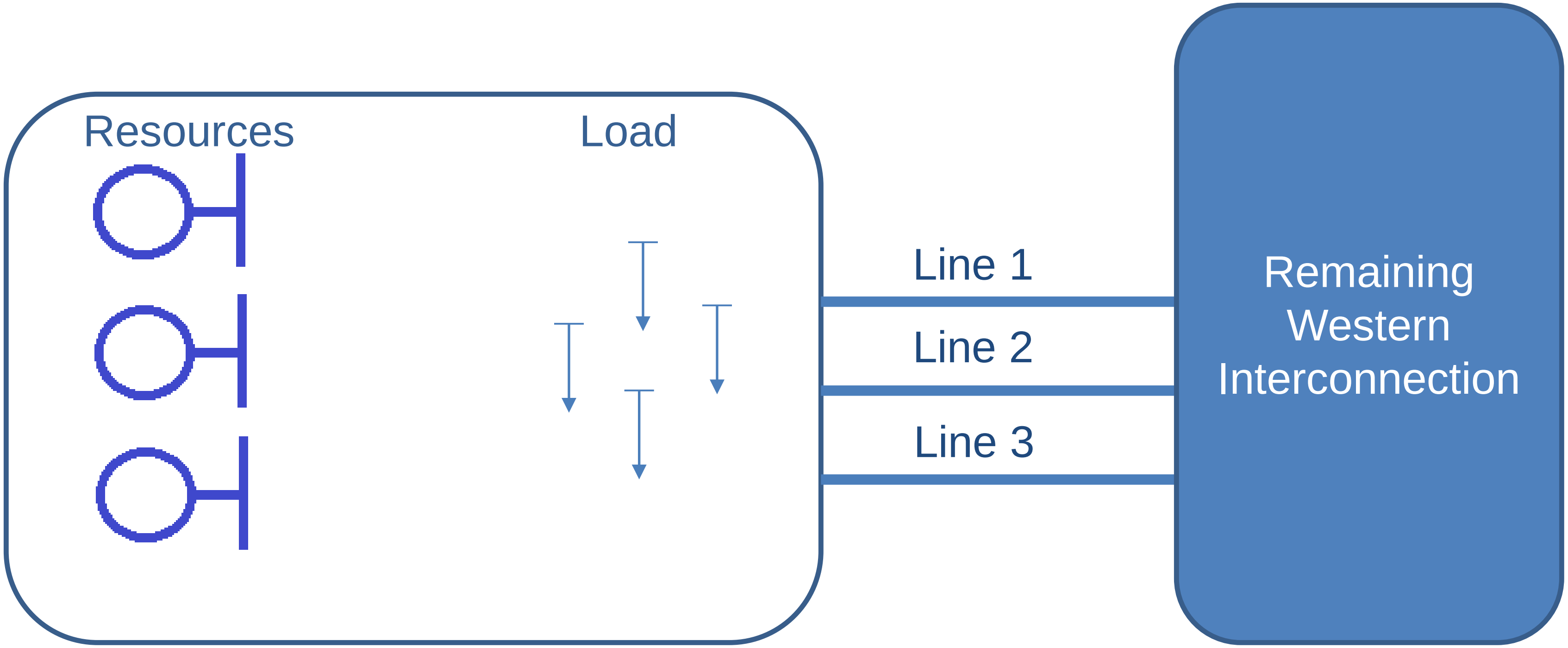
The LCR Performance criteria for Category C is to reflect generation capacity that is needed to readjust the system to prepare for the loss of a second transmission element (N-1-1)

Example:

N-1-1 means loss of Line 1 followed by loss of Line 2



Current Implementation - Example



1. ISO forecast the "Area" load in Day Ahead
2. ISO calculate "import limit" into the area to protect for the N-1-1
3. ISO ensures that there is Minimum Online Commitment (MOC) to meet the "import limit" for the N-1-1

MOC (Minimum Online Commitment)

- MOC is currently used for ensuring N-1-1 security
- MOC setup requires two things:
  - Resources that are eligible to solve the issue
  - MOC MW requirement for those pool of resources

$$\sum_{i \in G} a_i \, Y_{i,t} \, P_{i,t}^{\max} \geq P_{G,t}^{moc} \qquad \forall t, G \qquad (1)$$

Where:

$P_{G,t}^{moc}$ is the minimum total online commitment required for interval t for the defined set of generating resources G.

a_i is a multiplier representing effectiveness for the resource i in meeting Minimum Online Commitment requirement

$Y_{i,t}$ is the commitment status for market resource i for interval t

$P_{i,t}^{\max}$ is the total maximum operating limit of the market resource i and interval t, as derated by SLIC of the resource (if appropriate)

  - While commitment selection of the resources considers the economic and cost, the shadow prices of these MOC constraints are not incorporated directly into any pricing calculations.

MOC (Minimum Online Commitment)

MOC Requirement =

Forecasted Load – Import Limit – Resources that can be committed and fully dispatched within the readjustment period

MOC Resource Pool =

All resources inside the area that cannot be committed within the readjustment period

What is needed for MOC to work

- List of resources in the area
- Sufficient RA resources have to be offered in Day Ahead market to meet the requirement
- Hourly load forecast for the area
- Import limit into the area

MOC will consider economic in the commitment (Start up cost, min load cost, energy cost, min run time, max run time, etc).

It picks the most economical resources to meet the requirement for the 24 hour interval

Implementation Details- Resource Management

Gigio Sakota
Energy Forecasting and Integration
Southern California Edison

SOUTHERN CALIFORNIA EDISON®

An EDISON INTERNATIONAL® Company

Market Bidding Challenges for Demand Response Resources

CAISO / CPUC Joint Workshop DR Requirements for Local RA Needs

2016-10-03

Background – Demand Response

- Demand Response (DR) is generally a Use-Limited Resource (ULR), integrated as PDR or RDRR into the CAISO market.
  - PDRs can be bid economically into both Day-Ahead and Real-Time market.
  - RDRRs can be bid economically into Day-Ahead, and with a contingency flag in Real-Time market.
- PDR / RDRR economic bids must account for both variable (energy) cost and opportunity (use limit) cost.
  - Use limited resource should be used at the times of highest need (value)
  - PDR and RDRR bids are not subject to bid insertion and bid mitigation; hence their energy bids can include opportunity costs.
- Opportunity costs are calculated based on forecast future value of the resource, as to preserve the resource for the highest value hours.
  - E.g. a resource with 100 hours of availability would ideally be dispatched during the 100 hours of highest system need (prices).

Current DR Program Limitations

- SCE has several programs that have been integrated into the CAISO
  - In 2016, SCE integrated 70+ DR Resources with over 1,100 MW of capacity
  - Each program has separate characteristics and limitations
- DR Program have limitations to minimize customer impacts
  - Summer Discount Plan (SDP) has hourly limits
  - Agricultural Pumping – Interruptible (API) has hourly and event limits
- Each limitation is binding
  - For example, once API is called 25 times, it is done for the year

Program	Max Hours/Year	Max Hours/Day	Max Events/Year
SDP	180	6	n/a
API	150	6	25

Illustrative DR Bidding Example (1)

Resource with hourly limits (e.g. 180 hours per year)

- Assume a 10 MW PDR with a $50/MWh energy cost.
  - Hourly dispatch cost would be $50/MWh x 10 MW x 1 hour = $500
  - An energy-only bid would be $50/MWh
- Without an opportunity cost bid adder, the resource would be used any time market prices clear at or above $50/MWh
  - If more than 180 hours clear above $50/MWh, the resource would be used during the first hours to cross the threshold, and not during the highest priced hours.
- Assume 180th highest forecast price hour is $150/MWh, then the opportunity cost is $100/MWh ($150/MWh – $50/MWh energy cost)
  - Hourly dispatch cost would be $1,000 + $50/MWh x 10 MW x 1 hour = $1,500
  - Appropriate energy-only bid would be $1,500 / 10 MWh = $150/MWh

Opportunity cost inclusion allows for ULR optimization – so the resource is dispatched during highest need (price) hours.

Challenges with DR Commitment Costs

- DR resources generally have limited number of calls (not MWh), hence the opportunity cost is a per call/hour (not per MWh) cost.
  - E.g. Summer Discount Plan (SDP) allows for 180 hours of dispatch, independent of how many MWh are delivered; hence the opportunity cost is per dispatch hour.
- DR Resources cannot be "block bid" into the market; and as a result can be partially dispatched for less MW and hours than available.
  - Current rules don't allow for a discrete dispatch bids (e.g. "x" MW for "y" hours).
  - Some programs limit the number of calls, but allow for multiple hours per call.
- Partial awards/dispatches still count as full calls.
  - A partial SDP dispatch counts toward the hourly limit just like a full dispatch does.
  - A 1-hour API dispatch counts toward the event limit just like a 6-hour dispatch.

Energy bids alone are inadequate for capturing DR opportunity costs

Illustrative DR Bidding Example (2)

Resource with hourly limits (e.g. 180 hours per year)

- Assume a 10 MW PDR with a $1,000 per hour net opportunity cost, and a $50/MWh energy cost.
  - Hourly dispatch cost would be $1,000 + $50/MWh x 10 MW x 1 hour = $1,500
  - An energy-only bid would be $1,500 / 10 MWh = $150/MWh
- If such a resource is partially dispatched, it is used sub-optimally
  - A partial dispatch (e.g. 5 MW) would recover only a fraction of the opportunity cost (5 MW x $150/MWh = $750) – meaning the resource could have been used at a time of higher system need (value).
- Bidding in at a higher cost could result in the opposite problem, with the resource again used sub-optimally
  - If the resource was bid at $250/MWh, to fully recover the variable and opportunity costs in a partial dispatch, it may not be called even if market prices hit $249 – meaning the resource is not being used at a time of high system need.

A min-load cost may better capture hourly DR limitations.

Illustrative DR Bidding Example (3)

Resource with call limits (e.g. 25 calls per year).

- Assume a 10 MW PDR with a $4,000 per call net opportunity cost, a $50/MWh energy cost, and a 4-hour availability.
  - A 4-hour dispatch cost would be $4,000 + $50/MWh x 10 MW x 4 hours = $6,000
  - An energy-only bid would be $6,000 / 40 MWh = $150/MWh
- If such a resource is partially dispatched, it is used sub-optimally
  - A partial dispatch (e.g. 5 MW for 2 hours) would recover only a fraction of the opportunity cost (5 MW x 2 hours x $150/MWh = $1,500) – meaning the resource could have been used at a time of higher system need (value).
- Bidding in at a higher cost could result in the opposite problem, with the resource again used sub-optimally
  - If the resource was bid at $450/MWh, to fully recover the variable and opportunity costs in a partial dispatch, it may not be called even if market prices hit $449 – meaning the resource is not being used at a time of high system need.

A startup cost may better capture per-call DR limitations.

BTM Energy Storage as DR

- Energy Storage resources have physical & contractual use limitations
  - Hourly limits (per day/month/year)
  - Call (cycling) limits (per day/year)
  - Dispatch and charging hours limits
    - Seller can only charge in "off-peak" hours; Buyer can only dispatch (bid into CAISO) in "on-peak" hours
- Use limitations lead to challenges in bidding opportunity costs
  - Storage faces challenges shown in both examples above (startup & min-load costs)
  - Daily start limits cannot be directly managed w/ bids and RDTs
    - Max. Daily Energy Limit does not address multiple starts or varying MW (e.g. A/C load)
- Energy Storage resources are expected to have more dispatches
  - While higher availability is a good quality, a mismatch between market rules and resource use limitations may cause increased challenges and sub-optimal resource dispatch

Outstanding Questions

- How would the CAISO calculate the opportunity costs for DR ULRs?
  - What is the methodology the CAISO would use? (Or would it defer to the SC?)
  - How would the CAISO track the resource use?
- How should Scheduling Coordinators manage yearly use limitations on a monthly basis?
  - How should we allocate yearly limits to a single month? (We shouldn't!)
    - Monthly allocations could result in arbitrary over (or under) use in a single month
  - When do we enter the work outage card?
    - What if a yearly limit is not exhausted, but resource has been dispatched multiple times within a single month?

Additional DR Challenges

- There is currently no option to bid economically in Real-Time for RDRRs that have an economic Day-Ahead Award (i.e. no dec bids).
  - Often, when a resources is awarded at a relatively high price in DAM, RTM prices can be significantly lower due to change in system conditions (e.g. lower temps).
  - Even though the RT prices may not meet the Net Benefits Test threshold, there is no mechanism for the CAISO to “call-off” awards if RDRRs are no longer needed.
  - A possible solution would be to allow economic “dec” bids, similar to non-DR resources. E.g. RDRRs with Day-Ahead awards could be exempt from the current requirement for RDRR RT bids at 95% of bid cap.
- (Re)activating Maximum Run Time for DR
  - Daily energy limits do not work well for DR, as the resource capacity often changes throughout the day (e.g. AC cycling capabilities vary by hour).

Next Steps

- SCE hopes to continue the discussions on how to more effectively integrate Demand Response and BTM Energy Storage resources into the CAISO markets, and maximize the value of such resources.
- For questions and comments, please contact:

  Gigio.Sakota@sce.com

Implementation Details- Resource Design & Attributes

What implications do the preliminary study results have on DR resource designs, operations, and planning?

- Study addresses short-term RA need. How to incorporate DR into long-term planning studies, with assurance that DR will reliably offset transmission and generation investments year-after-year?
- Concerns about fatigue and consistency of response.
- What "other uses" will be placed on local DR? How many more hours of availability are needed?
- At minimum, local DR must meet local availability needs; hours may exceed minimum RA requirements.
- If local DR is used for other purposes for consecutive days, and then pre-contingency dispatch occurs- no opportunity for cool down period. Impacts?

Wrap-up

- Closing remarks
- Action items
- Next steps