Agenda – Day 1 & 2
Preliminary Reliability Assessment Results

Kim Perez
Stakeholder Engagement and Policy Specialist

2016-2017 Transmission Planning Process Stakeholder Meeting
September 21-22, 2016

2016-2017 Transmission Planning Process Stakeholder Meeting - Agenda – Day 1

Topic	Presenter
Introduction	Kim Perez
Overview	Chris Mensah-Bonsu
Key Issues	Neil Millar
Preliminary Reliability Results - North	ISO Regional Transmission Engineers
Review of Previously Approved North Projects	Jeff Billinton
Preliminary Reliability Results – South	ISO Regional Transmission Engineers
If time permits, the Economic Study Assumptions presentation may be advanced	*Yi Zhang*
Wrap-up & Next Steps	Kim Perez

2016-2017 Transmission Planning Process Stakeholder Meeting – Agenda – Day 2

Topic	Presenter
Introduction	Kim Perez
Special Studies updates	Planning Engineers
SDG&E Proposed Reliability Solutions	
SCE Proposed Reliability Solutions	
PG&E Proposed Reliability Solutions	
Economic Study Assumptions	Yi Zhang
Next Steps	Kim Perez

California ISO

Characteristics of Slow Response Local Capacity Resources Special Study

Preliminary Results

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

2016-2017 Transmission Planning Process Stakeholder Meeting
September 21-22, 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 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

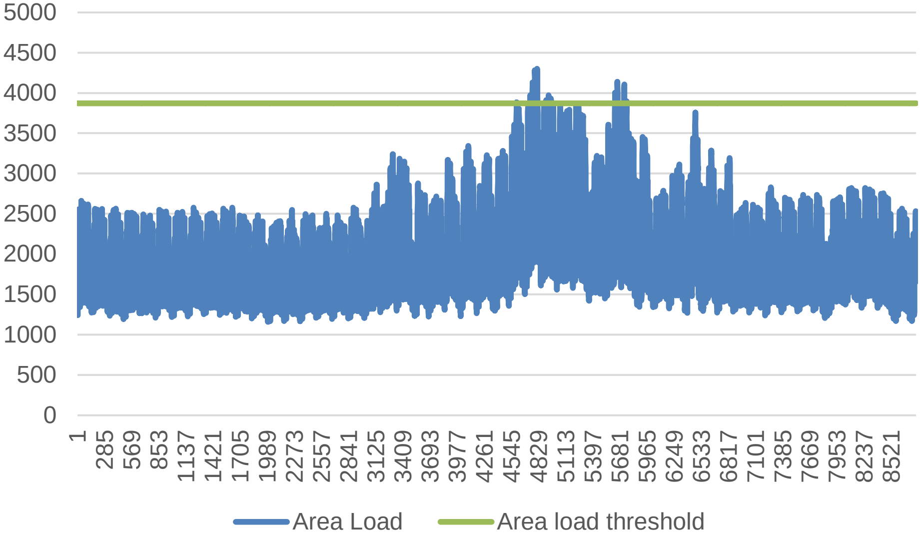
- LSEs selected LCAs and sub-areas to be studied and provided assessment using Method 1 – which assumes all resources are equally effective within a study area
- ISO:
    - reviewed LSE results
    - verified selected results using Method 2 – which tests locational and reactive capability impacts within 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

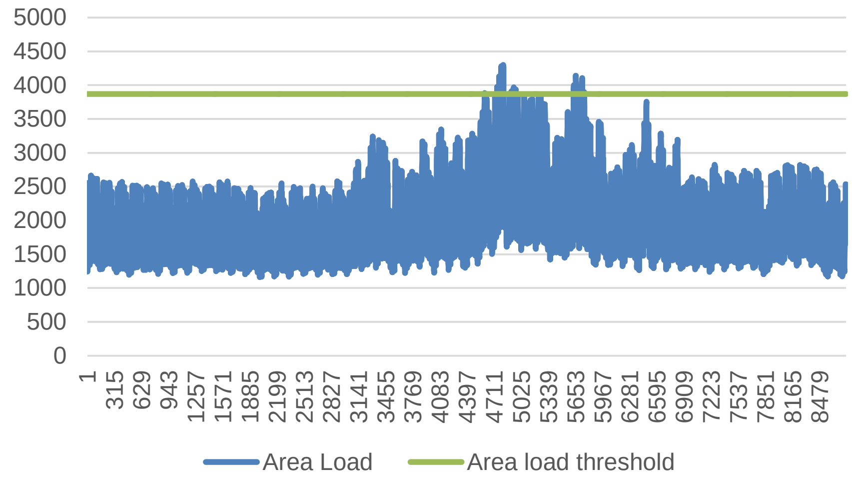
Study Steps – Method 1 (PTOs)

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 (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



SCE/SDG&E Area Results

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.

PG&E Area 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

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

- Availability requirements increase as the amount of DR (or other slow-response resources) counted for local RA increases.
- Setting an upper limit on the amount of DR to be counted for local RA may need to be considered. ISO requests comments regarding this from CPUC and stakeholders.
- 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?

Other considerations – cont'd

- The availability results are for local resource adequacy use. Upward adjustments may be needed to account for other non-coincident uses:
    - in response to price or triggers other than local capacity related reliability events
    - for system events or by PTOs for distribution system issues
    - due to planned outages and unforeseen events
    - for program evaluation
- 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.

Other considerations – cont'd

- DR contracts typically have short term. How to do long-term planning around DR resources?
- Concerns about future availability as event burden increases – will customers drop off? This is particularly a concern in areas where slow-response DR is used to avoid investment in transmission or other assets with longer contract terms.

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

Study Contacts

PTO	Contact Info.
SCE	Garry Chinn, Transmission Planning, Garry.Chinn@sce.com
PG&E	Xiaofei (Sophie) Xu, Transmission Planning, x1x1@pge.com
SDG&E	H. McIntosh, Transmission Planning hmcintosh@semprautilities.com
ISO	Nebiyu Yimer, Regional Transmission, nyimer@caiso.com Catalin Micsa, Regional Transmission, cmicsa@caiso.com

Thank you

California ISO

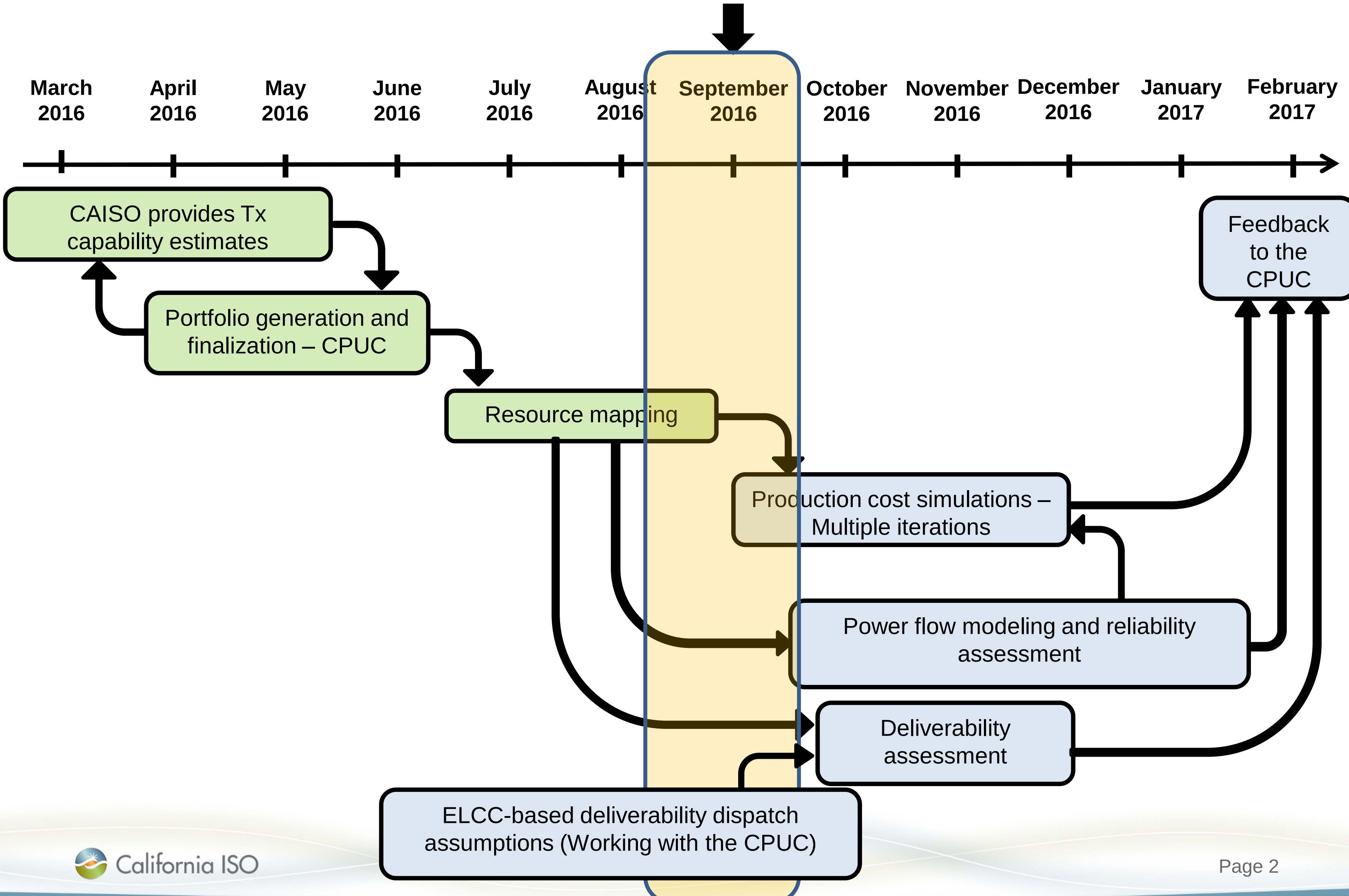
50% Special Study and Interregional Coordination Update

Performed as part of 2016-2017 Transmission Planning Process

Sushant Barave and Gary DeShazo

September 21-22, 2016

50% Special Study Status Update



50% Special Study Status Update

Completed and on-going tasks:

- Portfolio finalization (June, 2016)
- In-state resource mapping (August-September 2016)
- Base case merging for creating consolidated portfolio cases (August 2016)
- Out-of-state resource mapping
  - Coordinating with the regional planning entities
  - Candidate locations in WY and NM have been identified (August 2016)
- Modeling of portfolios resources into power flow cases and production cost database
- ELCC-based dispatch assumptions for deliverability assessment
  - Working with the CPUC on data analysis

Yi might have an update on the prod cost model in the economic studies presentation.

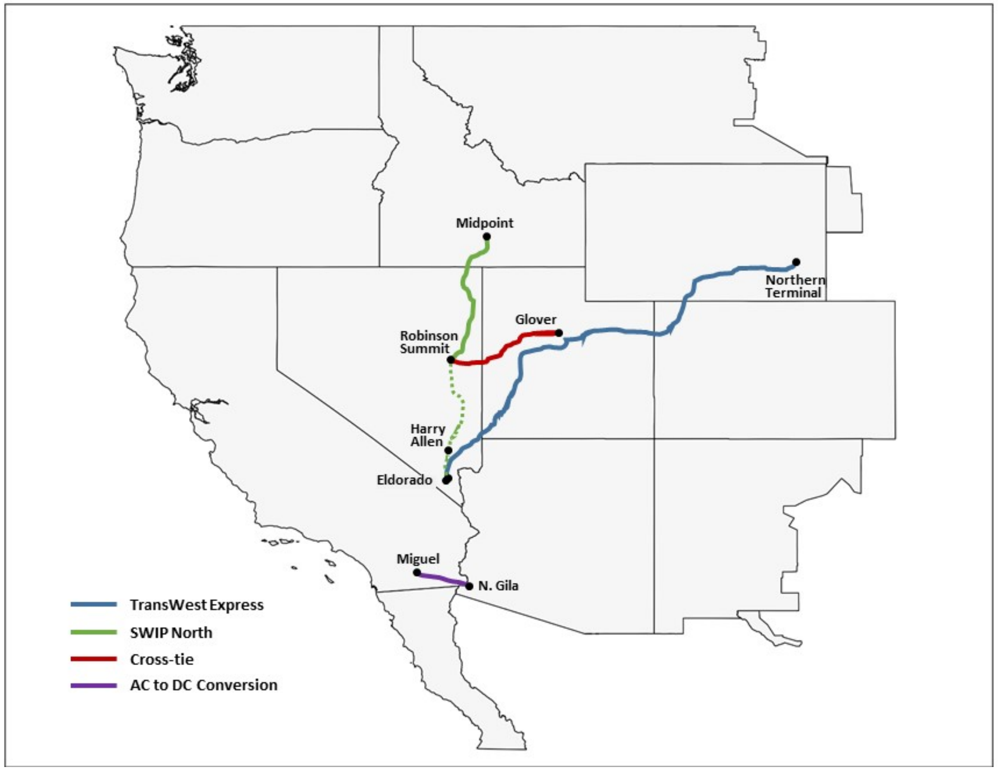
Next steps:

- Finalize out-of-state resource mapping
- Power flow studies
  - Dispatch portfolio resources in the base cases
  - Reliability studies (four portfolios – two FCDS and two EO)
  - Deliverability studies (two portfolios - FCDS)
- Production cost simulations
- An update at the TPP Stakeholder Meeting #3 (November 2016)
- Feedback to the CPUC (February 2017)

Four ITPs were submitted to the California ISO, NTTG, and WestConnect

- TransWest Express
  - *California ISO*
  - *NTTG*
  - *WestConnect*
- SWIP North
  - California ISO
  - *NTTG*
  - *WestConnect*
- Cross-tie Project
  - California ISO
  - *NTTG*
  - *WestConnect*
- AC/DC Conversion Project
  - *California ISO*
  - *WestConnect*

Relevant Planning Region



- ITP evaluation plans for each of the submitted ITPs have been developed by the California ISO, NTTG, and WestConnect and posted on their websites

Note that all four projects may facilitate access to out of state renewables. However, SWIP North and Cross-tie will be tested for potential benefits without out of state renewables as well.

Update on coordination with regional planning entities for out-of-state portfolio modeling and assessment

- Considering RETI 2.0 objectives of considering wind renewables in Wyoming and New Mexico, NTTG and WestConnect have agreed to include California 50% scenarios in their 2016-2017 regional studies
- The California ISO, NTTG, and WestConnect developed evaluation plans for each of the ITP proposals
- Subject matter experts from all four regions have been engaged in coordination of input data for the WECC 2026 Common Case and other base cases that will be used in their regional planning studies
- The development of study plans for studying the ITP proposals are under development
  - Align study assumptions, study methodology, and timelines
  - Resource scenarios
- The California ISO will facilitate the California 50% scenario work with NTTG and WestConnect
- Although not a Relevant Planning Region, ColumbiaGrid will be included in coordination activities to ensure consistency across all planning regions

Questions?

Gas-Electric Coordination Summer 2017 Transmission Planning Assessment for Various Gas Curtailment Scenarios with the Aliso Canyon Gas Storage Outage

David Le
Senior Advisor, Regional Transmission Engineer
Regional Transmission South

2016-2017 Transmission Planning Process Stakeholder Meeting
September 21-22, 2016

Overview - Southern California discussion

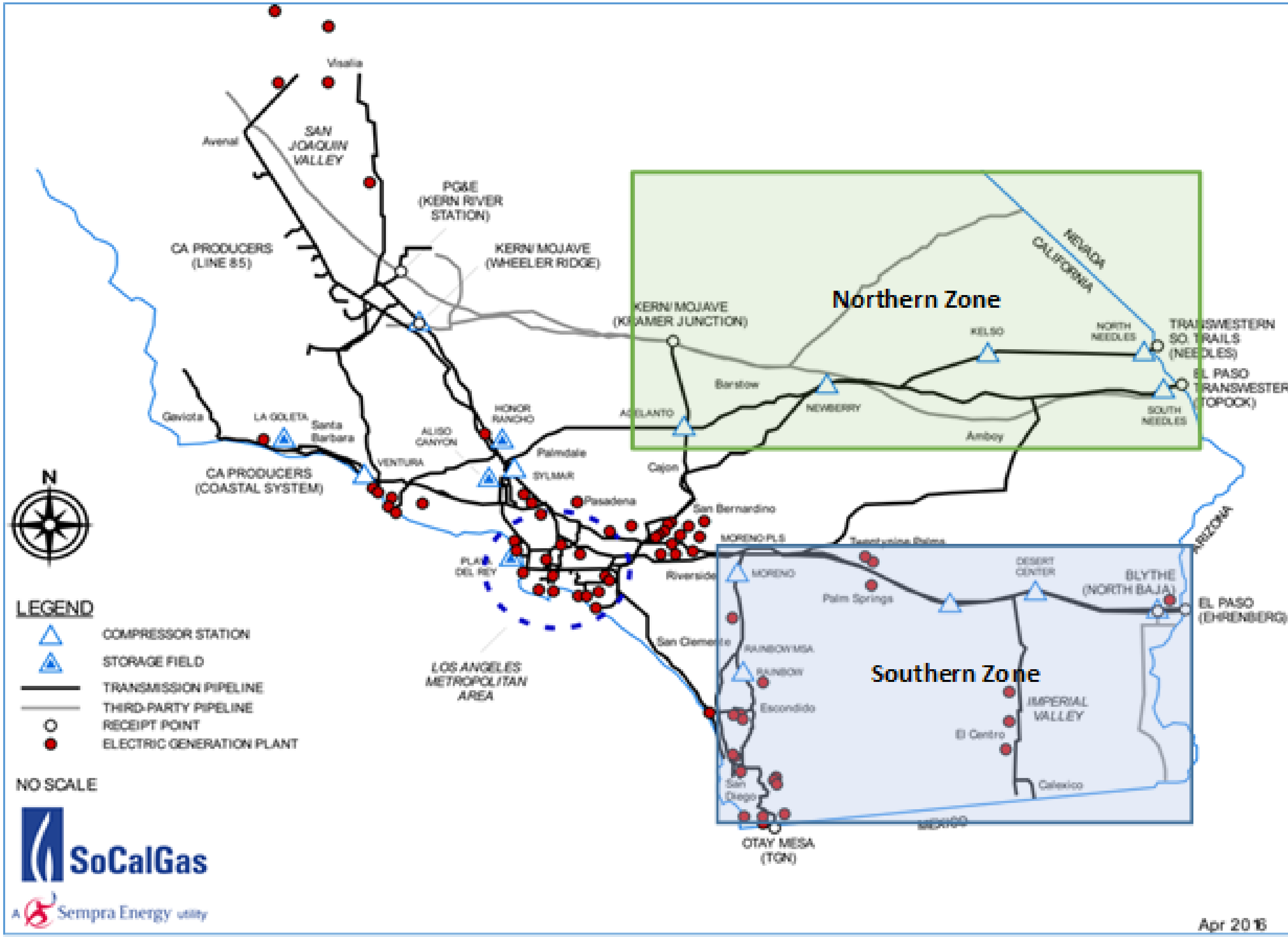
- Background information

- Summary gas-electric coordination summer 2017 transmission planning assessment for various gas curtailment scenarios with the Aliso Canyon gas storage outage

- Next steps

Background Information

Gas storage plays an important role in maintaining gas and electric reliability in southern California



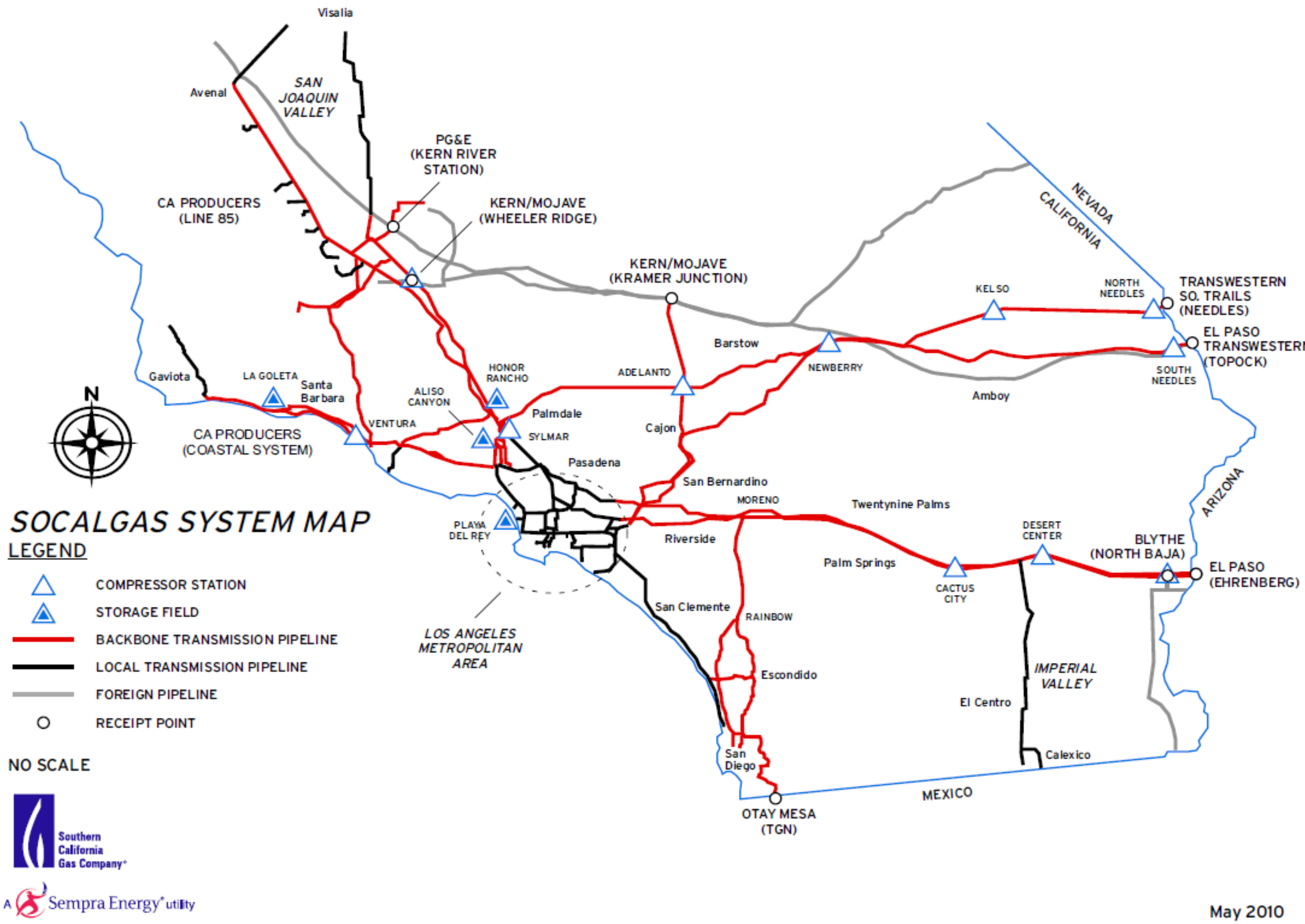
Gas is delivered by a network of major gas pipelines and gas storage facilities

- Major gas storage facilities include the following:
  - La Goleta (12 Bcf storage capacity) is located in Santa Barbara County
  - Honor Rancho (26 Bcf storage capacity) is located in the Los Angeles County near the foothills of Valencia
  - Aliso Canyon (86 Bcf storage capacity) is located in the Santa Susana Mountains in the Los Angeles County north of Porter Ranch neighborhood of the City of Los Angeles
  - Playa Del Rey (2.6 Bcf storage capacity) is located near Balloma Wetlands between Marina Del Rey and LAX in the Los Angeles County (operational gas reserve)
- Major interstate gas pipelines include the following:
  - El Paso Natural Gas Company
  - North Baja – Baja Norte Pipeline, which takes gas off the El Paso Pipeline at the California/Arizona border, and delivers that gas through California into Mexico
  - Kern River Transmission Company
  - Mojave Pipeline Company
  - Questar's Southern Trails Pipeline Company
  - Transwestern Pipeline Company

The Aliso Canyon gas storage constraint and its importance to southern California reliability

- Aliso Canyon is the largest gas storage field
  - Inventory capacity of 86.2 Bcf
  - Withdrawal capacity at 1,860 MMcfpd
  - Typically used during summer time to provide hourly peak electric generation demands throughout the day, which cannot be met with pipeline supplies because of the magnitude and speed that these peak demand require
  - Currently holds about 15 Bcf of storage under moratorium of new injections until comprehensive review and inspection of storage wells is completed
- In April 2016, the Reliability Task Force, consisting of the CEC, CPUC, ISO, and LADWP with participation from SoCal Gas Company completed the Aliso Canyon Risk Assessment Technical Report (http://www.energy.ca.gov/2016_energypolicy/documents/2016-04-08_joint_agency_workshop/Aliso_Canyon_Risk_Assessment_Technical_Report.pdf) quantifying the potential impacts to electric generation under various gas curtailment scenarios with the Aliso Canyon gas storage outage constraint for the summer 2016 time frame.

Directly Affects 17 Gas-fired Plants Generating ~9800MW; Indirectly Affects 48 Plants Generating 20,120MW



Current Status

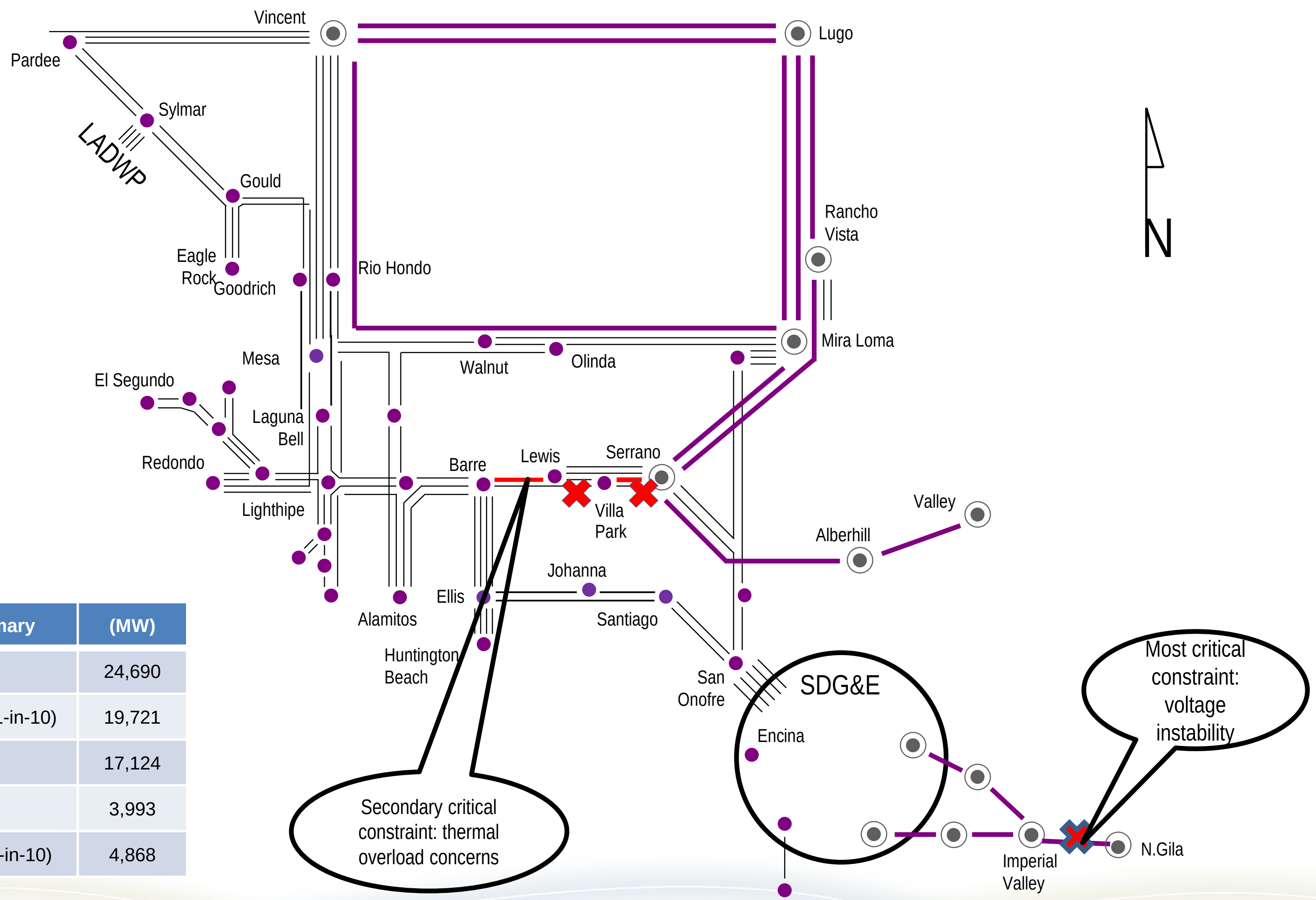
- Summer is not over. Significant risk remains.
- 15 Bcf remains in the Aliso field
- Safety review is continuing
- Unknown when SoCalGas will apply to begin injections; cleared wells may produce less due to influx of liquids
- SoCalGas must retain enough wells to withdraw 420 mmcfd through summer
- 21 mitigation measures were implemented for summer
- Made it through heat events in June and in July, thanks to combination of good planning (with mitigation measures) and luck (with weather better than forecast)

Summer 2017 Transmission Planning Assessment for Various Gas Curtailment Scenarios

Reliability assessment for minimum generation requirement for the LA Basin and San Diego areas

- Study was performed similar to the Joint Agency Task Force technical assessment for summer 2016.
- Minimum generation in the LA Basin and San Diego areas was evaluated to maintain operational reliability for the normal conditions and for the next contingency (i.e., NERC P0 and P1 reliability criteria as performed for the Joint Agency Task Force technical assessment).
- Gas burns required for meeting minimum generation were compared with net amount of actual gas burns that occurred on Sept. 9, 2015, minus gas curtailment amount due to the following major gas facility outage scenarios:
  - Scenario 1 – Aliso Canyon gas storage unavailable; supply shortfall of 150 MMcfpd of gas between scheduled and actual gas flows
  - Scenario 2 – Scenario 1 plus a non-Aliso Canyon gas storage outage, reducing 400 MMcfd of system capacity
  - Scenario 3 – Scenario 1 plus a major gas pipeline outage reducing 500 MMcfd of system capacity
  - Scenario 4 – Combination of Scenarios 1, 2 and 3 resulting in an overall reduction of 900 MMcfd of system capacity.

Identified reliability concerns with minimum generation in the LA Basin and San Diego areas



Load / Flow Summary	(MW)
Total SCE load	24,690
Total LA Basin load (1-in-10)	19,721
Total SCIT	17,124
Path 26 Flow	3,993
Total SDG&E load (1-in-10)	4,868

Electric generation impact due to gas curtailments under various gas outage scenarios for the most critical transmission reliability concern

			Gas Curtailment Scenarios with Aliso Canyon Gas Storage Outage			
Row	Description	Formula	Scenario 1: Aliso Canyon Gas Storage Outage	Scenario 2: With Other Storage Outage	Scenario 3: With Major Pipeline Outage	Scenario 4: Overlapping Outages (1+2+3)
1	Original Curtailment for day - Volume by SCG (MMcfd) (Calculated by SCG)		180	480	600	1,100
2	Number of Hours of Curtailment		8	8	8	8
3	Curtailment Volume - During 8 hour Peak Period (MMcf for 8 hour)	(Row 1/24)*1.4*Row 2	84	224	280	513
4	Total ISO Balancing Area in SoCalGas system Gas Burn with minimum generation (MMcf) **for the most critical transmission constraint**	7487 MW*8 hours/103 MWh/MMcf	582	582	582	582
5	Total LADWP Balancing Area Minimum Generation Burn (MMcf)		124	124	124	124
6	Combined ISO and LADWP Minimum Gen Gas Burn (MMcf)	Row 4 + Row 5	706	706	706	706
7	Actual ISO SCG system September 9, 2015 Gas Burn (MMcf)		760	760	760	760
8	Actual LADWP September 9 Gas Burn (MMcf)		163	163	163	163
9	Combined Actual ISO And LADWP Gas Burns		923	923	923	923
10	(ISO + LADWP) Actual Burns - Total Gas Curtailment (MMcf)	Row 9 - Row 3	839	699	643	410
11	ISO + LADWP Gas Burn Short/Surplus (Delta) (MMcf)	Row 10 - Row 6	133	-7	-63	-296
12	ISO+LADWP Energy Conversion of Gas Burn Short/Surplus for the day (MWh)	Row 11*103MWh/MMcf	13,749	-671	-6,439	-30,472
13	ISO+LADWP MW Conversion of Gas Burn Short per hour (MW)	Row 12/Row 2	1,719	-84	-805	-3,809
14	Customer Impacted	Row 13*700	0	58,713	563,413	2,666,329

Identified transmission constraints

	Identified constraints (1=Most constrained)	Contingency	Planned and approved transmission projects	Estimated gas-fired generation need reduction associated with implementation of approved transmission projects	Notes
1	Post-transient voltage instability	N-1: Imperial Valley – N.Gila 500kV line	Synchronous condensers at the following locations: - San Luis Rey (2x225 Mvar) - San Onofre (225 Mvar) - Santiago (225 Mvar)	About 500 MW	These projects are under construction and have planned in-service date by December 2017 at the earliest. The study also assumed operation of both Huntington Beach synchronous condensers (i.e., Units 3 & 4)
2	Barre-Lewis 230 kV line thermal loading concern	N-1: Barre-Villa Park 230 kV line	Mesa 500 kV Loop-In project	About 500 MW*. Once #2 is mitigated, constraints 3 - 5 closely follow. Notes: *The 500 MW benefits are for the minimum generation condition associated with Aliso Canyon constraint for the P1 reliability criteria. For normal local capacity requirement assessment, the benefits of the Mesa Loop-In project can bring about 700 MW of gas-fired generation reduction for the P6 reliability criteria (source: the ISO 2015-2016 Transmission Plan).	The Mesa Loop-In project is currently under review in the CPUC environmental permitting process. This project has an in-service date of December 2020 at the earliest, but could be delayed beyond summer 2021 if the CPUC . However, the schedule could potentially be delayed to 2021 or after due to uncertainty when the construction permit is granted by the CPUC.
3	Barre-Villa Park 230 kV line thermal loading concern	N-1: Barre-Lewis 230 kV line	See above		
4	Serrano-Villa Park #2 230 kV line thermal loading concern	N-1: Serrano-Villa Park #1 230kV line	See above		
5	Sylmar-Eagle Rock 230kV line thermal loading concern	N-1: Sylmar-Gould 230kV line	See above		

Electric generation impact due to gas curtailments under various gas outage scenarios (after the most critical reliability constraint is mitigated)

			Gas Curtailment Scenarios with Aliso Canyon Gas Storage Outage			
Row	Description	Formula	Scenario 1: Aliso Canyon Gas Storage Outage	Scenario 2: With Other Storage Outage	Scenario 3: With Major Pipeline Outage	Scenario 4: Overlapping Outages (1+2+3)
1	Original Curtailment for day - Volume by SCG (MMcfd) (Calculated by SCG)		180	480	600	1,100
2	Number of Hours of Curtailment		8	8	8	8
3	Curtailment Volume - During 8 hour Peak Period (MMcf for 8 hour)(	(Row 1/24)*1.4*Row 2	84	224	280	513
4	Total ISO Balancing Area in SoCalGas system Gas Burn with minimum generation (MMcf)	6997 MW*8 hours/103 MWh/MMcf	543	543	543	543
5	Total LADWP Balancing Area Minimum Generation Burn (MMcf)		124	124	124	124
6	Combined ISO and LADWP Minimum Gen Gas Burn (MMcf)	Row 4 + Row 5	667	667	667	667
7	Actual ISO SCG system September 9, 2015 Gas Burn (MMcf)		760	760	760	760
8	Actual LADWP September 9 Gas Burn (MMcf)		163	163	163	163
9	Combined Actual ISO And LADWP Gas Burns		923	923	923	923
10	(ISO + LADWP) Actual Burns - Total Gas Curtailment (MMcf)	Row 9 - Row 3	839	699	643	410
11	ISO + LADWP Gas Burn Short/Surplus (Delta) (MMcf)	Row 10 - Row 6	172	32	-24	-258
12	ISO+LADWP Energy Conversion of Gas Burn Short/Surplus for the day (MWh)	Row 11*103MWh/MMcf	17,669	3,249	-2,519	-26,552
13	ISO+LADWP MW Conversion of Gas Burn Short per hour (MW)	Row 12/Row 2	2,209	406	-315	-3,319
14	Customer Impacted	Row 13*700	0	0	220,413	2,323,329

Summary of Findings

- The potential impact to electric generation due to various gas curtailment scenarios for summer 2017 exhibits similar trend as was evaluated for summer 2016
  - Gas burn shortfall is observed for three gas curtailment scenarios (i.e., #2 through 4), similar to the Joint Agency Task Force findings
- Both Huntington Beach synchronous condensers Units #3 and 4 are needed to maintain post-transient voltage stability for the minimum gas generation condition for the P1 reliability criteria
- The following are observed (see slides 11 and 13):
  - The gas burn for minimum generation requirement would be reduced by 543 MMcf (about 500 MW of generation) if the most critical reliability concern (i.e., post transient voltage instability) can be mitigated by the timely addition of planned dynamic reactive supports. These planned transmission projects, however, are under construction and cannot be placed in service until December 2017 at the earliest.
  - With this reduction, a gas burn shortfall would occur for two gas curtailment scenarios instead of three (i.e., Scenarios #3 and 4)

Summary of Findings (cont'd)

- The next reliability concern, after the post-transient stability issue is mitigated, is thermal loading concern for a number of 230 kV lines in the Orange County and Los Angeles County areas
  - The Mesa Loop-In project, which was approved by the ISO Board, will be able to mitigate these various thermal loading concerns
  - This project is currently under review by the CPUC as part of the environmental permitting process. The project currently has a planned in-service date of December 2020 if a final decision is granted for the Permit to Construct by December 2016. Potential delay for the project's in-service date beyond summer 2021 could occur if the final decision is delayed beyond December 2016 timeframe.
- The ISO has also evaluated other options for potential interim solutions for mitigating thermal loading constraints. However, high capacity transmission lines in the LA Basin (due to bundled conductor construction), coupled with congested real estate conditions, pose a significant challenge in implementing interim solution in a timely manner.
- Additionally, since the primary transmission constraint is related to the post transient voltage stability concern, mitigating this issue with planned transmission projects is needed before potential benefits of other options for thermal loading mitigation can be realized.

Next steps

- A longer planning horizon (summer 2026) reliability assessment will be performed with the following assumptions included in the power flow study case:
  - Once-through-cooled generation is retired in the LA Basin and San Diego subarea;
  - Long term procurement plan resources (preferred resources and conventional resources) that were approved by the CPUC;
  - Energy storage projects that were approved by the CPUC;
  - Transmission projects that were approved by the ISO Board.
- Study results for the long-term assessment will be presented at the third ISO stakeholder meeting in November 2016.

Frequency Response Assessment-Generation Modeling Special Study – Update

Irina Green

Senior Advisor, Regional Transmission North

2016-2017 Transmission Planning Process Stakeholder Meeting

September 21-22, 2016

Drivers for the Study

- Frequency response studies performed in the 2015-2016 Transmission Plan showed optimistic results regarding frequency response
- Actual measurements of the generators' output were lower that the generators' output in the simulations
- Therefore models update and validation is needed
- New NERC Standards MOD-032-1 and MOD -033-1 require to have accurate validated models
- Generation owners are responsible for providing the data, and the ISO is responsible for the model validation

Study Plan and Methodology

- Identify missing models or missing model components
- Identify models that have deficiencies and require upgrades
- Point to generators that are modeled with generic models with typical parameters and obtain more accurate models of the units
- The models with deficiencies will be identified by comparison of the real time measurements and the simulation results, or if measurements are not available, by unrealistic performance in the simulations
- This task will be performed in coordination with the System Operations who will provide the real-time measurement data.
- Updated models will be reported to WECC to be included in the dynamic stability model database.
- Details provided in June 13, 2016 Stakeholder Call material

Key activities under ISO control on track, with models with concerns identified through:

- Reviewed WECC Dynamic Master File and identified old models, missing models, models with wrong type, or models with typical generic data.
- Based on the transient stability study results for the 2016-2017 TPP, identified renewable projects that were tripped by under- or over-voltage and frequency protection with three-phase faults even if they were supposed to have Fault-Ride-Through Capability.
- Identified thermal units that showed oscillations in transient stability simulations with three-phase faults in their vicinity, most likely caused by errors in exciter models or incorrect tuning (high gains)
- Based on the frequency response studies performed for the 2015-2016 TPP, identified several hydro units with inadequately high frequency response.
- Identified approximately 460 generators with issues needing resolution by generation owners

The common model errors:

- Renewable generators are modeled using the first generation or unapproved models instead of second generation models (RE_ model series).
- Many renewable generators do not have low/high voltage and frequency ride-through models.
- Models are missing for some generators.
- Generators are modeled with typical data.
- Small generators are modeled as 100 MVA.
- Unsatisfactory simulation results, such as oscillations, high governor response.

Other activities

- Work is continuing on other tracks as well to identify problematic modeling:
  - Comparing responses observed in DSA to that in state estimator for events during 2016 and see how the models can be modified to provide comparable averages for the 20 to 52 second time period.
  - Validating existing dynamic models using two recent (2016) system events.
  - The work on validation will complete by 10/31/2016
- PTOs are being notified of modeling issues with generators in their territories and being advised to contact generation owners
- If required, the ISO may also contact the owners whose generators have potential issues that have already been identified, explain their issues and request to update the models, preferably by testing their units. All notifications will be sent out by 11/30/2016.

QUESTIONS?

COMMENTS?

A Bulk Energy Storage Resource Case Study with 50% RPS

Shucheng Liu
Principal, Market Development

2016-2017 Transmission Planning Process Stakeholder Meeting
September 21-22, 2016

Purpose of the ISO bulk energy storage case study:

- To assess a bulk storage resource’s ability to reduce
  - production cost
  - renewable curtailment
  - CO2 emission
  - renewable overbuild to achieve the RPS target
- To analyze the economic feasibility of the bulk storage resource
- To consider the locational benefits of known potential bulk energy storage locations in ISO footprint

Plan for the bulk energy storage study in the 2016-17 planning cycle

- The 2016-2017 planning cycle will include the bulk energy storage study using 2016-2017 updated assumptions

- The study will also consider transmission-related economic benefits including congestion benefits provided by the bulk energy storage at potential sites

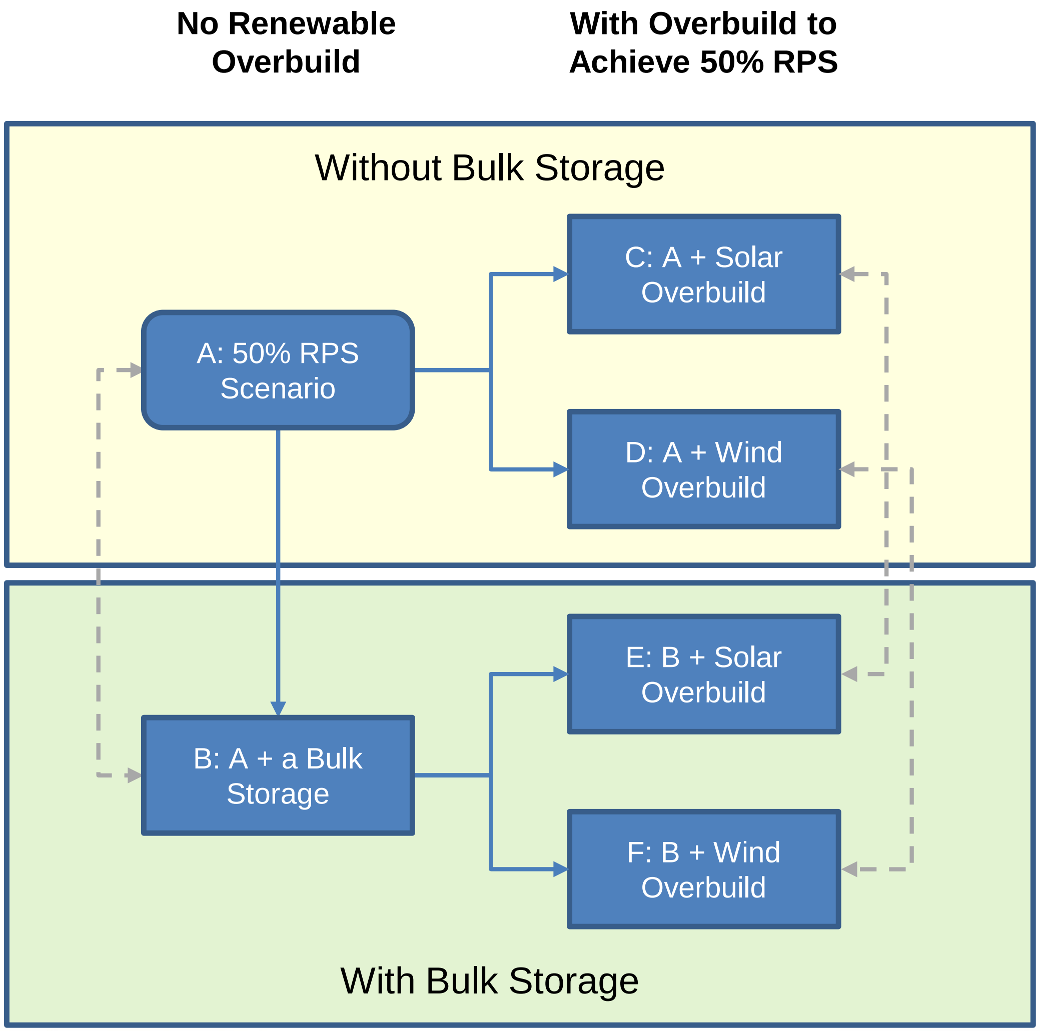
Summary of system-wide study assumptions

- The study will initially be based on the Default Scenario of the CPUC ALJ Ruling on the Assumptions and Scenarios for 2016 LTPP and the ISO 2016-17 TPP
  - 1-in-2 peak mid case of 2015 IEPR demand forecast
  - Double AAEE by 2030, interpolated to 2026
  - 43.3% RPS portfolio in 2026
  - Diablo Canyon retired in 2024/25
- The 43.3% RPS portfolio may be replaced with a 50% RPS portfolio for special study from the CPUC

System-wide study approach

- Using a zonal model, with only inter-zonal transmission constraints enforced
- Analyzing two renewable build baselines, with and without a new bulk energy storage resource,
  - No overbuild of renewable resources
  - Overbuilding renewables to achieve 50% RPS target
- Overbuilding only solar or wind to demonstrate the benefits of more diversified RPS portfolios

Definition of the study cases and expected takeaways



This study quantifies

- reduction of production cost, renewable curtailment and CO2 emission,
- quantity and cost of renewable overbuild
- cost and market revenue of the bulk storage resource

It does not quantify

- transmission impact

Assumptions of the new pumped storage resource, which represents the bulk energy storage

Item	Value
Number of units	**2**
Max pumping capacity per unit (MW)	**300**
Minimum pumping capacity per unit (MW)	75
Maximum generation capacity per unit (MW)	**250**
Minimum generation capacity per unit (MW)	5
Pumping ramp rate (MW/min)	**50**
Generation ramp rate (MW/min)	**250**
Round-trip efficiency	**83%**
VOM Cost ($/MWh)	**3**
Maintenance rate	8.65%
Forced outage rate	6.10%
Upper reservoir maximum capacity (GWh)	8
Upper reservoir minimum capacity (GWh)	2
Interval to restore upper reservoir water level	Monthly
Pump technology	**Variable speed**
Reserves can provide in generation and pumping modes	**Regulation, spinning and load following**
Reserves can provide in off modes	**Non-spinning**
Location	Southern California

Assumptions of revenue requirements and RA revenue of the new resources

Item	Revenue Requirement ($/kW-year)		NQC Peak Factor [1]	RA Revenue ($/kW-year) [2]
	Generation Resource [3]	Transmission Upgrade [4]		
Large Solar In-State	327.12	22.00	47%	16.13
Large Solar Out-State	306.26	22.00	47%	16.13
Small Solar In-State	376.99	11.00	47%	16.13
Solar Thermal In-State	601.71	22.00	90%	30.89
Wind In-State	286.62	16.50	17%	5.83
Wind Out-State	261.13	72.00	45%	15.44
Pumped Storage In-State	383.62	16.50	100%	34.32

[1] References https://www.caiso.com/Documents/2012TACAreaSolar-WindFactors.xls and https://www.wecc.biz/Reliability/2024-Common-Case.zip
[2] Reference http://www.cpuc.ca.gov/NR/rdonlyres/2AF422A2-BFE8-4F4F-8C19-827ED4BA8E03/0/2013_14ResourceAdequacyReport.pdf
[3] References https://www.wecc.biz/Reliability/2014_TEPPC_GenCapCostCalculator.xlsm and https://www.wecc.biz/Reliability/2014_TEPPC_Generation_CapCost_Report_E3.pdf
[4] Reference http://www.transwestexpress.net/scoping/docs/TWE-what.pdf and the CAISO assumptions.

Locational benefits – Gridview and powerflow/stability analysis

- Known potential sites: Lake Elsinore, Eagle Mountain, San Vicente
- Consider local resource adequacy capacity benefits using local capacity requirements study
- Consider transmission line loss benefits through powerflow analysis
- Consider congestion management benefits through Gridview production simulation analysis
  - 2016-2017 economic study parameters
  - Potential gaps between assumptions of system-wide analysis and location-constrained analysis

Other considerations:

- Consider distributed batteries as an alternative?
- Consider a single level of pumped storage for transmission unconstrained results and scale results to varying sizes employed in locational analysis?

Questions?

Economic Early Retirement of Gas Fired Generation Special Study – Scope and Methodology Update

Jeff Billinton

Manager - Regional Transmission -North

September 21-22, 2016

2016-2017 Transmission Planning Process Stakeholder Meeting

Study Approach

- Preliminarily screening to identify areas of potential early retirement using the ISO’s 2015-2016 production cost models (PCM) with 50% renewable portfolios
- Power flow and stability studies modeling the identified potential early retirement using ISO’s 2016-2017 power flow cases
- Assessment of congestion and system requirements, ancillary and flexibility, using ISO’s 2016-2017 PCM

Revised Study Methodology

- The following criteria are used to identify potential early retirement
  - Capacity factor below typical historical values, and
  - Not required to meet Local Capacity Requirement (LCR)
- The latest long-term LCR results will be used
  - 2020 LCR for PG&E areas
  - 2025 LCR for SCE and SDG&E areas
- LCR generators will be selected up to the LCR need based upon the capacity factor in preliminary production cost modeling screening.
  - Sensitivity of LCR generators to meet LCR need that will replace system generators with similar technical specifications will also be assessed

Revised Study Methodology *(continued)*

- Assessment to be conducted to determine generation to retire based upon capacity factor
- With scenarios of generation identified for potential early retirement assessment will be undertaken to:
  - Determine if adequate generation to meet ancillary service requirements
  - Determine if adequate generation to meet flexibility requirements
  - Determine if there are any reliability or path limitations

Next steps

- Conducting preliminary screening
- Power flow and stability studies using 2016-2017 ISO's power flow cases
- Production cost simulation using 2016-2017 ISO's PCM with 50% renewable portfolios
- Will provide update at the November 16 stakeholder meeting

California ISO

Economic Planning-
Production cost model development

Yi Zhang
Regional Transmission Engineer Lead

2016-2017 Transmission Planning Process Stakeholder Meeting
September 21-22, 2016

Steps of economic planning studies

Economic planning studies

(Step 1)
Unified study assumptions

→

(Step 2)
Development of production cost model

→

(Step 3)
Preliminary study results

→

(Step 4)
Final study results

↑ Economic planning study requests

Database development

- Starting point
  - TEPPC 2026 Common Case V1.3 released by TEPPC in August, 2016
- ISO's major updates by September, 2016
  - Latest CEC load forecast for all CAISO areas,
    - BTM and AAEE are modeled as hourly resources
  - Local constraints identified in reliability and LCR assessments
  - Frequency response requirements for combine cycle units and batteries at unit level
  - All ISO approved transmission projects
  - Renewable generators to meet 33% RPS
  - 50% portfolios

Next steps

- Continue on database development, mainly:
  - Update transmission constraints based on the latest reliability study results
  - Coordinate with WECC on the modeling issues in TEPPC Common Case identified by planning regions and WECC
- Conduct production cost simulations and congestion analysis
- Conduct simulations for 50% renewable portfolios
- Provide update in the November 16 Stakeholder Meeting

Questions/Comments?

Next Steps

Kim Perez
Stakeholder Engagement and Policy Specialist

2016-2017 Transmission Planning Process Stakeholder Meeting
September 21-22, 2016

2016-2017 Transmission Planning Process
Next Steps

- Comments due October 6
  - (slow response resource special study extended to October 10)
- Request window closes October 15
- ISO recommended projects:
  - For management approval of reliability projects less than $50 million will be presented at November stakeholder session
  - For Board of Governor approval of reliability projects over $50 will be included in draft plan to be issued for stakeholder comments by January 31, 2015