Opening

2014-2015 Transmission Planning Process Stakeholder Meeting

Tom Cuccia
Lead Stakeholder Engagement and Policy Specialist
November 19-20, 2014

Yesterday's Agenda – November 19th

Topic	Presenter
Opening	Tom Cuccia
Introduction & Overview	Neil Millar
San Francisco Peninsula Extreme Event Reliability Assessment	Jeff Billinton
Over Generation Assessment	Irina Green
Recommendations for Management Approval of Reliability Projects less than $50 Million	ISO Regional Transmission Engineers
Long-Term Local Capacity Need Analysis	Catalin Micsa and David Le
Locational Effectiveness Factors	David Le

Today's Agenda – November 20st

Topic	Presenter
Opening	Tom Cuccia
RPS Portfolio Assessment	ISO Regional Transmission Engineers
Summary of LA Basin/San Diego and Imperial Area Interaction	Robert Sparks
2013-2014 CAISO Transmission Planning Process Harry Allen – El Dorado 500 kV Project Economic Analysis	Robert Sparks
Economic Study Assessment	Yi Zhang
Long-Term CRR Assessment	Chris Mensah-Bonsu

Policy Driven Planning Deliverability Assessment Assumptions

2014-2015 Transmission Planning Process Stakeholder Meeting

Lyubov Kravchuk
Senior Regional Transmission Engineer
November 19-20, 2014

Overview

- Deliverability assessment is performed for the base portfolio in all areas and the sensitivity portfolio in selected areas.
- Follow the same on-peak deliverability assessment methodology as used in generation interconnection study.

Objectives of Portfolio Deliverability Assessment

- Determine deliverability of the Target Maximum Import Capability
- Determine deliverability of renewable resources inside CAISO BAA
- Identify transmission upgrades to support full deliverability of the renewable resources and Target MIC

Import Assumptions

- Maximum summer peak simultaneous historical import schedules (2015 Maximum RA Import Capability)
- Historically unused Existing Transmission Contracts are initially modeled by equivalent generators at the tie point.
- IID import through IID-SCE and IID-SDGE branch groups is increased from 2015 MIC to support porfolio renewables in IID.

Generation Assumptions

- Deliverability assessment is performed for generating resources in the base portfolio.
- Generation capacity tested for deliverability
  - Existing non-intermittent resources: most recent summer peak NQC
  - New non-intermittent resources: installed capacity in the base portfolio
  - Intermittent resources: 50% (low level) and 20% (high level) exceedance during summer peak load hours

Load and Transmission Assumptions

- ISO 2024 1-in-5 load
- Same transmission assumptions as power flow studies.
  - Existing transmission
  - Approved transmission upgrades

Policy Driven Planning Deliverability Assessment Results – SCE/VEA Area

2014/2015 Transmission Planning Process Stakeholder Meeting

Lyubov Kravchuk
Senior Regional Transmission Engineer
November 19-20, 2014

Overview of renewable zones that impact SCE area

Renewable Zone	Base Portfolio MW
Distributed Solar - SCE	565
Imperial	1000
Kramer	642
Mountain Pass	658
Nevada C	516
Non-CREZ	48
Riverside East	3800
San Bernardino - Lucerne	87
Tehachapi	1,653

Deliverability Assessment Results for SCE Area – North of Inyokern

Overloaded Facility	Contingency	Flow
Inyo 115kV phase shifter	Base Case	102.66%

North of Inyokern Deliverability Constraint	
Constrained Renewable Zones	Kramer (north of Inyokern)
Total Renewable MW Affected	64 MW
Deliverable MW w/o Mitigation	< 60 MW
Mitigation	Upgrade Inyo phase shifter
	Local constraint to be addressed in generation interconnection

Deliverability Assessment Results for SCE Area – West of Coolwater 115kV

Overloaded Facility	Contingency	Flow
Coolwater – RPSC0015 115kV	Base Case	226.28%
	Dunnside – PRCS0015 115kV	220.76%
	Dunnside – Baker – Mountain Pass 115kV	220.10%
	Mountain Pass – Ivanpah 115kV	203.99%
Diverged	Coolwater – RPS0015 115kV	--
Coolwater - Tortilla - Segs2 115kV No. 1 (Tortilla leg)	Kramer - Coolwater 115kV No. 1	107.94%

Deliverability Assessment Results for SCE Area – West of Coolwater 115kV (Cont.)

West of Coolwater 115kV Deliverability Constraint	
Constrained Renewable Zones	Kramer (Coolwater 115kV)
Total Renewable MW Affected	230 MW
Deliverable MW w/o Mitigation	< 80 MW
Mitigation	2nd Coolwater – RPSC0015 115kV line and SPS tripping generation
	Local constraint to be addressed in generation interconnection

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Deliverability Assessment Results for SCE Area – East of Riverside East 500kV

Overloaded Facility	Contingency	Flow
Devers – Red Bluff 500kV No. 1	Devers – Red Bluff 500kV No. 2	123.70%
Devers – Red Bluff 500kV No. 2	Devers – Red Bluff 500kV No. 1	120.28%

Riverside East 500kV Deliverability Constraint	
Constrained Renewable Zones	Riverside East
Total Renewable MW Affected	3800 MW
Deliverable MW w/o Mitigation	< 2900 MW
Mitigation	SPS bypassing the series cap on the overloaded line to bring the flow below 30-min rating; then re-dispatch to bring the flow below 4-hr rating.
	Mitigated by SPS and operating procedure

Policy Driven Planning Deliverability Assessment Results – SDG&E Area

2014-2015 Transmission Planning Process Stakeholder Meeting

Luba Kravchuk
Sr. Regional Transmission Engineer
November 19-20, 2014

Overview of renewable zones that impact SDG&E area – Base Portfolio

Renewable Zone	Base Portfolio MW
Arizona	400
Baja	100
Distributed Solar – SDG&E	143
Imperial	1,000

Deliverability Assessment Results for SDG&E Area – Miguel 500/230 kV transformers (Base Portfolio)

Overloaded Facility	Contingency	Flow
Miguel 500/230 kV #1	Miguel 500/230 kV #2	104%
Miguel 500/230 kV #2	Miguel 500/230 kV #1	103%

Constrained Renewable Zones	Baja, Imperial
Total Renewable MW Affected	1,100 MW
Mitigation	Modify IV SPS to include generation tripping following Miguel 500/230 kV transformer N-1 outages

Deliverability Assessment Results for SDG&E Area – Otay Mesa-Tijuana 230 kV line (Base Portfolio)

Overloaded Facility	Contingency	Flow
Otay Mesa-Tijuana 230 kV	Otay Mesa-Miguel 230 kV #1 and Otay Mesa-Miguel 230 kV #2	114%
RUM-ROA 230 kV		143%
ROA-HRA 230 kV		133%
RUM-HRA 230 kV		132%
MEP-TOY 230 kV		103%

Constrained Renewable Zones	N/A
Total Renewable MW Affected	N/A
Mitigation	modify existing Otay Mesa SPS due to Miguel Tap Reconfiguration Project

Overview of renewable zones that impact SDG&E area – Commercial Sensitivity (CS) Portfolio

Renewable Zone	Commercial Sensitivity Portfolio MW
Arizona	400
Baja	100
Distributed Solar – SDG&E	143
Imperial	2,500

Deliverability Assessment Results for SDG&E Area – (CS Portfolio)

Overloaded Facility	Contingency	Flow
Miguel 500/230 kV #1	Miguel 500/230 kV #2	110%
Miguel 500/230 kV #2	Miguel 500/230 kV #1	109%
Sycamore-Suncrest 230 kV #2	Sycamore-Suncrest 230 kV #1	104%
Sycamore-Suncrest 230 kV #1	Sycamore-Suncrest 230 kV #2	104%
Suncrest 500/230 kV #2	Suncrest 500/230 kV #1	105%
Suncrest 500/230 kV #1	Suncrest 500/230 kV #2	105%
Miguel-Bay Boulevard 230 kV #1	Miguel-Mission 230 kV #1 and #2	102%

Deliverability Assessment Results for SDG&E Area – (CS Portfolio) – cont.

Overloaded Facility	Contingency	Flow
IV-ECO 500 kV	Suncrest-Ocotillo 500 kV	116%
	Suncrest-Sycamore 230 kV #1 and #2	116%
	Imperial Valley-Ocotillo 500 kV	111%
ECO-Miguel 500 kV	Suncrest-Ocotillo 500 kV	118%
	Suncrest-Sycamore 230 kV #1 and #2	117%
	Imperial Valley-Ocotillo 500 kV	112%
Sycamore-Suncrest 230 kV #1	ECO-Miguel 500 kV	111%
	Imperial Valley-ECO 500 kV	110%
Sycamore-Suncrest 230 kV #2	ECO-Miguel 500 kV	111%
	Imperial Valley-ECO 500 kV	110%

Deliverability Assessment Results for SDG&E Area – (CS Portfolio) – cont.

Overloaded Facility	Contingency	Flow
Path 46 (West of River)	Base Case	102%

Deliverability Assessment Results for SDG&E Area – (CS Portfolio) – cont.

Constrained Renewable Zones	Baja, Imperial
Total Renewable MW Affected	2,600 MW
Mitigation	By-pass series capacitors on ECO-Miguel 500 kV and ECO-Suncrest 500 kV lines Modify IV SPS to include generation tripping following Miguel 500/230 kV transformer N-1 outages Above mitigation is sufficient for 1,900 to 2,100 MW of portfolio generation Midway-Devers 500 kV line or STEP project would be expected to increase West of River WECC path rating to accommodate the full 2600 MW of Baja and Imperial generation

Policy Driven Assessment Results – Southern CA Area Power Flow and Stability

2014-2015 Transmission Planning Process Stakeholder Meeting

Sushant Barave
Sr. Regional Transmission Engineer

November 19-20, 2014

Study summary (to be updated)

- Consolidated PG&E, SCE, SDGE and VEA 2024 peak load base cases to have a system wide base cases
- Modeled 2014/2015 33% RPS base portfolio
- Modeled renewable generation output, and EOR (Path 49) flow as identified in the last planning cycle
- OTC replacement amounts authorized by CPUC LTPP Track 1 and Track 4 were modeled

Commercial Interest Portfolio – South

	Biogas	Biomass	Geo-thermal	Hydro	Large Scale Solar PV	Small Solar PV	Solar Thermal	Wind	Grand Total
Arizona	-	-	-	-	400	-	-	-	**400**
Baja	-	-	-	-	-	-	-	100	**100**
Distributed Solar - SCE	-	-	-	-	-	565	-	-	**565**
Distributed Solar - SDGE	-	-	-	-	-	143	-	-	**143**
Imperial	-	-	30	-	791	10	-	169	**1,000**
Kramer	-	-	64	-	230	20	250	78	**642**
Mountain Pass	-	-	-	-	300	-	358	-	**658**
Nevada C	-	-	116	-	400	-	-	-	**516**
NonCREZ	5	103	25	-	-	52	-	-	**185**
Riverside East	-	-	-	-	3,038	20	742	-	**3,800**
San Bernardino - Lucerne	-	-	-	-	45	-	-	42	**87**
Tehachapi	10	-	-	-	1,007	98	-	538	**1,653**

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Commercial Sensitivity Portfolio – South

	Biogas	Biomass	Geo-thermal	Hydro	Large Scale Solar PV	Small Solar PV	Solar Thermal	Wind	Grand Total
Arizona	-	-	-	-	400	-	-	-	**400**
Baja	-	-	-	-	-	-	-	100	**100**
Distributed Solar - SCE	-	-	-	-	-	565	-	-	**565**
Distributed Solar - SDGE	-	-	-	-	-	143	-	-	**143**
Imperial	-	-	572	-	1,638	25	-	265	**2,500**
Kramer	-	-	64	-	230	20	250	78	**642**
Mountain Pass	-	-	-	-	300	-	358	-	**658**
Nevada C	-	-	116	-	400	-	-	-	**516**
NonCREZ	5	103	25	-	-	49	-	-	**182**
Riverside East	-	-	-	-	800	-	600	-	**1,400**
San Bernardino - Lucerne	-	-	-	-	-	-	-	42	**42**
Tehachapi	10	-	-	-	1,007	98	-	368	**1,483**

High DG Portfolio – South

	Biogas	Biomass	Geo-thermal	Hydro	Large Scale Solar PV	Small Solar PV	Solar Thermal	Wind	Grand Total
Arizona	-	-	-	-	400	-	-	-	**400**
Baja	-	-	-	-	-	-	-	100	**100**
Distributed Solar - SCE	-	-	-	-	-	1,988	-	-	**1,988**
Distributed Solar - SDGE	-	-	-	-	-	157	-	-	**157**
Imperial	-	-	30	-	791	10	-	169	**1,000**
Kramer	-	-	-	-	-	-	62	-	**62**
Mountain Pass	-	-	-	-	-	-	165	-	**165**
Nevada C	-	-	116	-	150	-	-	-	**266**
NonCREZ	5	103	25	-	-	-	-	-	**133**
Riverside East	-	-	-	-	800	-	600	-	**1,400**
San Bernardino - Lucerne	-	-	-	-	-	-	-	42	**42**
Tehachapi	10	-	-	-	887	20	-	368	**1,285**

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Comparison of three portfolios

	CI	CS	HDG
Arizona	400	400	400
Baja	100	100	100
Distributed Solar - SCE	565	565	1,988
Distributed Solar - SDGE	143	143	157
Imperial	1,000	2,500	1,000
Kramer	642	642	62
Mountain Pass	658	658	165
Nevada C	516	516	266
NonCREZ	185	182	133
Riverside East	3,800	1,400	1,400
San Bernardino - Lucerne	87	42	42
Tehachapi	1,653	1,483	1,285

Overview of renewable zones that impact SDG&E area – Base Portfolio

Renewable Zone	Base Portfolio MW
Arizona	400
Baja	100
Distributed Solar – SDG&E	143
Imperial	1,000

RPS Reliability Results for SDG&E Area – Miguel 500/230 kV transformers (Base Portfolio)

Overloaded Facility	Contingency	Base
Miguel 500/230 kV Bank 80	Miguel 500/230 kV Bank 81	123%
Miguel 500/230 kV Bank 81	Miguel 500/230 kV Bank 80	121%

Mitigation
• 30-min emergency rating of 1615 MVA is not sufficient • Modify IV SPS to include generation tripping following Miguel 500/230 kV transformer N-1 outages

RPS Reliability Results for SDG&E Area – ROA-HRA 230 kV line (Base Portfolio)

Overloaded Facility	Contingency	Flow
ROA-HRA 230 kV line	Otay Mesa-Miguel 230 kV #1 and Otay Mesa-Miguel 230 kV #2	141%

Mitigation
• Modify existing Otay Mesa SPS due to Miguel Tap Reconfiguration Project

RPS Reliability Results for SDG&E Area – IV 500/230 kV Banks (Base Portfolio)

Overloaded Facility	Contingency	Flow
IV 500/230 kV Bank 80	IV Breaker 8022 (N. Gila – IV 500kV + IV 500/230 Bank 81)	118%
IV 500/230 kV Bank 82	IV Breaker 8022 (N. Gila – IV 500kV + IV 500/230 Bank 81)	105%

Mitigation
• Rely on 30-min emergency ratings (900 MVA for Bank 80 and 1680 MVA for Bank 82)

RPS Reliability Results for SDG&E Area – IV-ECO and ECO-Miguel 500 kV lines (Base Portfolio)

Overloaded Facility	Contingency	Flow
IV – ECO 500 kV line	Suncrest-Sycamore 230 kV #1 and #2	107%
ECO-Miguel 500 kV line	Suncrest-Sycamore 230 kV #1 and #2	111%

Mitigation
• SPS to trip generation for Suncrest – Sycamore 230kV line outages

RPS Reliability Results for SDG&E Area – Bay Blvd – Miguel 230 kV line (Base Portfolio)

Overloaded Facility	Contingency	Flow
Bay Blvd-Miguel 500 kV line	Miguel-Mission 230kV line #1 and #2	102%

Mitigation
• Congestion management, dispatch internal SDG&E generation or Pio Pico SPS

RPS Reliability Results for SDG&E Area – Voltage Issues (Base Portfolio)

Overvoltage Issues	Contingency	Voltage (pu)
Borrego 69kV	Base case	1.07
Narrows 69kV		1.06
Crestwood 69kV		1.06
North Gila 500kV		1.07

Mitigation
• Portfolio generation and DG to provide 0.95 lead/lag power factor

Overview of renewable zones that impact SDG&E area – Commercial Sensitivity (CS) Portfolio

Renewable Zone	Commercial Sensitivity Portfolio MW
Arizona	400
Baja	100
Distributed Solar – SDG&E	143
Imperial	2,500

RPS Reliability Results for SDG&E Area – Miguel 500/230 kV transformers (CS Portfolio)

Overloaded Facility	Contingency	CS
Miguel 500/230 kV Bank 80	Miguel 500/230 kV Bank 81	137%
Miguel 500/230 kV Bank 81	Miguel 500/230 kV Bank 80	134%

Mitigation
• 30-min emergency rating of 1615 MVA is not sufficient. Modify IV SPS to include generation tripping following Miguel 500/230 kV transformer N-1 outages

RPS Reliability Results for SDG&E Area – IV 500/230 kV transformers (CS Portfolio)

Overloaded Facility	Contingency	CS
IV 500/230 kV Bank 80	IV 500/230 kV Bank 81	129%
	IV 500/230 kV Bank 82	122%
	IV Breaker 8022 (N. Gila – IV 500kV + IV 500/230 Bank 81)	145%
IV 500/230 kV Bank 81	IV 500/230 kV Bank 80	101%
	IV 500/230 kV Bank 82	120%
	IV Breaker 11T (IV 500/230 kV Bank 80 + IV – CFE PST)	102%
IV 500/230 kV Bank 82	IV 500/230 kV Bank 81	116%
	IV Breaker 8022 (N. Gila – IV 500kV + IV 500/230 Bank 81)	130%

Mitigation
• 30-min emergency rating is sufficient except in case of Bank 80 for the IV breaker 8022 outage.

RPS Reliability Results for SDG&E Area – IV-ECO-Miguel 500 kV sections (CS Portfolio).

Overloaded Facility	Contingency	CS
IV-ECO 500 kV	Suncrest – Ocotillo 500 kV	135%
	Suncrest-Sycamore 230 kV #1 and #2	117%
ECO-Miguel 500 kV	Suncrest – Ocotillo 500 kV	137%
	Suncrest-Sycamore 230 kV #1 and #2	116%

Mitigation
• By-pass series capacitors on ECO-Miguel 500 kV and ECO-Suncrest 500 kV lines • SPS to trip generation for N-1 contingency of Suncrest-Sycamore 230 kV lines • Limit Imperial portfolio generation to 1700 to 1800 MW

RPS Reliability Results for SDG&E Area – Suncrest-Sycamore 230 kV lines (CS Portfolio)

Overloaded Facility	Contingency	CS
Suncrest-Sycamore 230 kV #1	Suncrest-Sycamore 230 kV #2	111%
	Miguel-ECO 500 kV	106%
	IV CB 8032 (ECO-IV + IV Bank 82)	102%
Suncrest-Sycamore 230 kV #2	Suncrest-Sycamore 230 kV #1	111%
	Miguel-ECO 500 kV	106%
	IV CB 8032 (ECO-IV + IV Bank 82)	102%

Mitigation
• By-pass series capacitors on ECO-Miguel 500 kV and ECO-Suncrest 500 kV lines • SPS to trip generation for N-1 contingency of Suncrest-Sycamore 230 kV lines • Limit Imperial portfolio generation to 1700 to 1800 MW

RPS Reliability Results for SDG&E Area – Suncrest 500/230 kV transformers (CS Portfolio)

Overloaded Facility	Contingency	CS
Suncrest 500/230kV Bank 80	Suncrest 500/230kV Bank 81	112%
Suncrest 500/230kV Bank 81	Suncrest 500/230kV Bank 80	112%

Mitigation
• Utilize the 30-min emergency rating • By-pass series capacitors on ECO-Miguel 500 kV and ECO-Suncrest 500 kV lines • Limit Imperial portfolio generation to 1700 to 1800 MW

RPS Reliability Results for SDG&E Area – Miguel-Bay Blvd 230kV line (CS Portfolio)

Overloaded Facility	Contingency	CS
Miguel-Bay Boulevard 230 kV #1	Miguel-Mission 230 kV #1 and #2	111%
	Sycamore-Artesan 230 kV + Sycamore-Penasquitos 230 kV	109%

Mitigation
• Congestion management, dispatch internal SDG&E generation or Pio Pico SPS

Policy-driven Assessment Results for SDG&E Area – Recommended Mitigation

1. By-pass series capacitors on ECO-Miguel 500 kV and ECO-Suncrest 500 kV lines

2. Modify IV SPS to include generation tripping following Miguel 500/230 kV transformer N-1 outages

3. Rely on 30 min emergency rating of 500/230kV banks at IV and Suncrest

Above mitigation is sufficient for 1,700 to 1,800 MW of incremental portfolio generation in Imperial CREZ

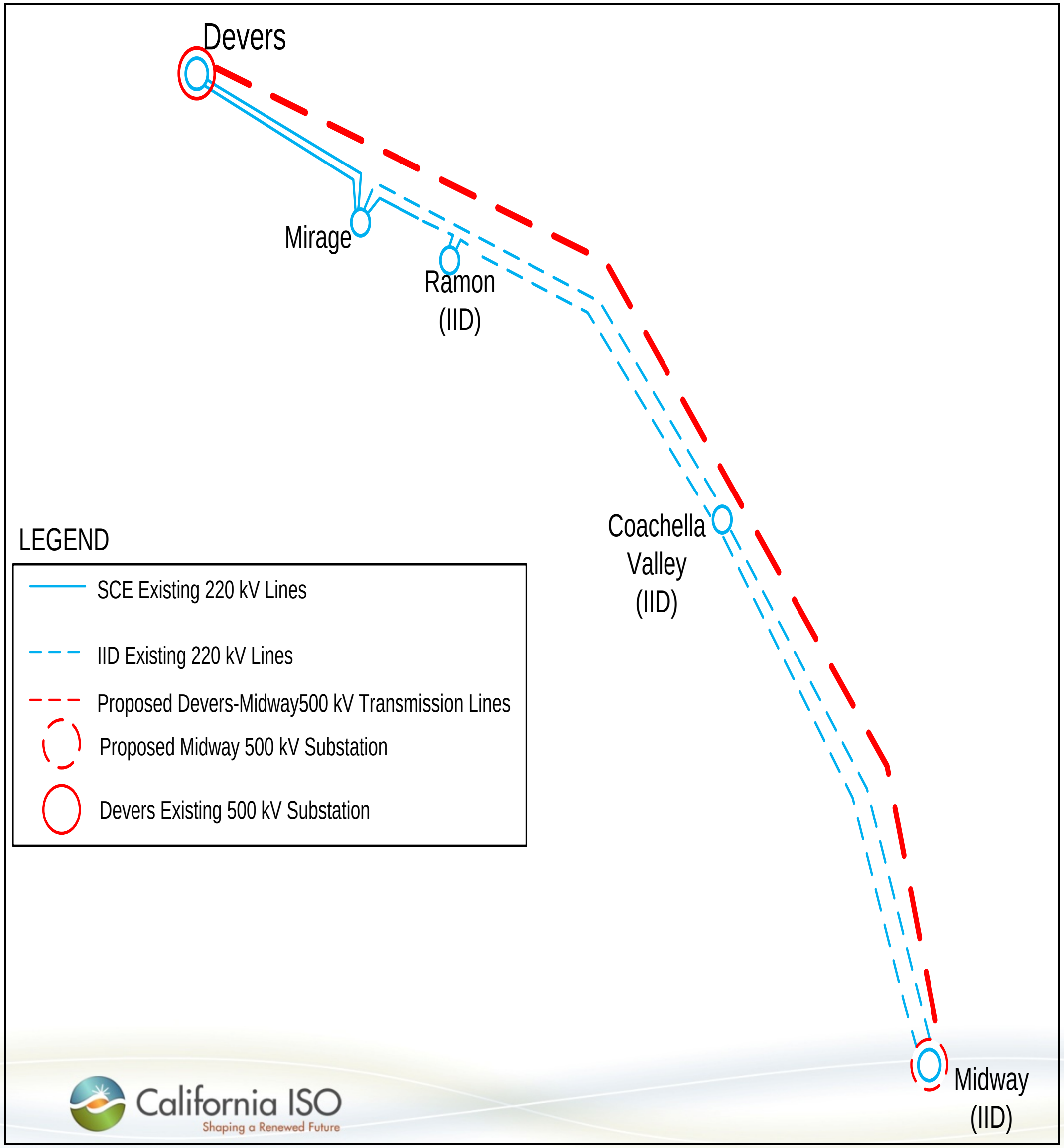
Summary of forecast available deliverability with identified mitigations and approved reinforcements

- Forecast deliverability from Imperial area: 1700 to 1800 MW incremental above existing generation
  - Note 330 MW solar ISO-connected, and 462 MW import from IID were considered “existing” in development of portfolios
- Renewable generation operational or under construction needing deliverability
  - Approximately 850 to 1000 MW connected to ISO
  - Approximately 200 MW in IID
- Subject to specific siting of new generation, 500 MW to 750 MW of additional deliverability may be available
  - Note that the ISO queue contains interconnection requests for several thousand MW, which may or may not proceed

Update on examination of alternatives to achieve 2500 MW Imperial area sensitivity:

- Effectiveness of two alternatives tested so far:
  - Midway-Devers 500 kV AC line
  - STEP transmission project
- Electrical performance of other proposals can be inferred from results for similar proposals, additional study may be required:
  - “SoCal-CETP” proposal (including phase 2 – Miguel area to Imperial Valley)
  - Midway-Devers DC line

Deliverability Assessment Results for SDG&E Area – Alternative Mitigation I



<u>Devers – Midway 500 kV line</u>

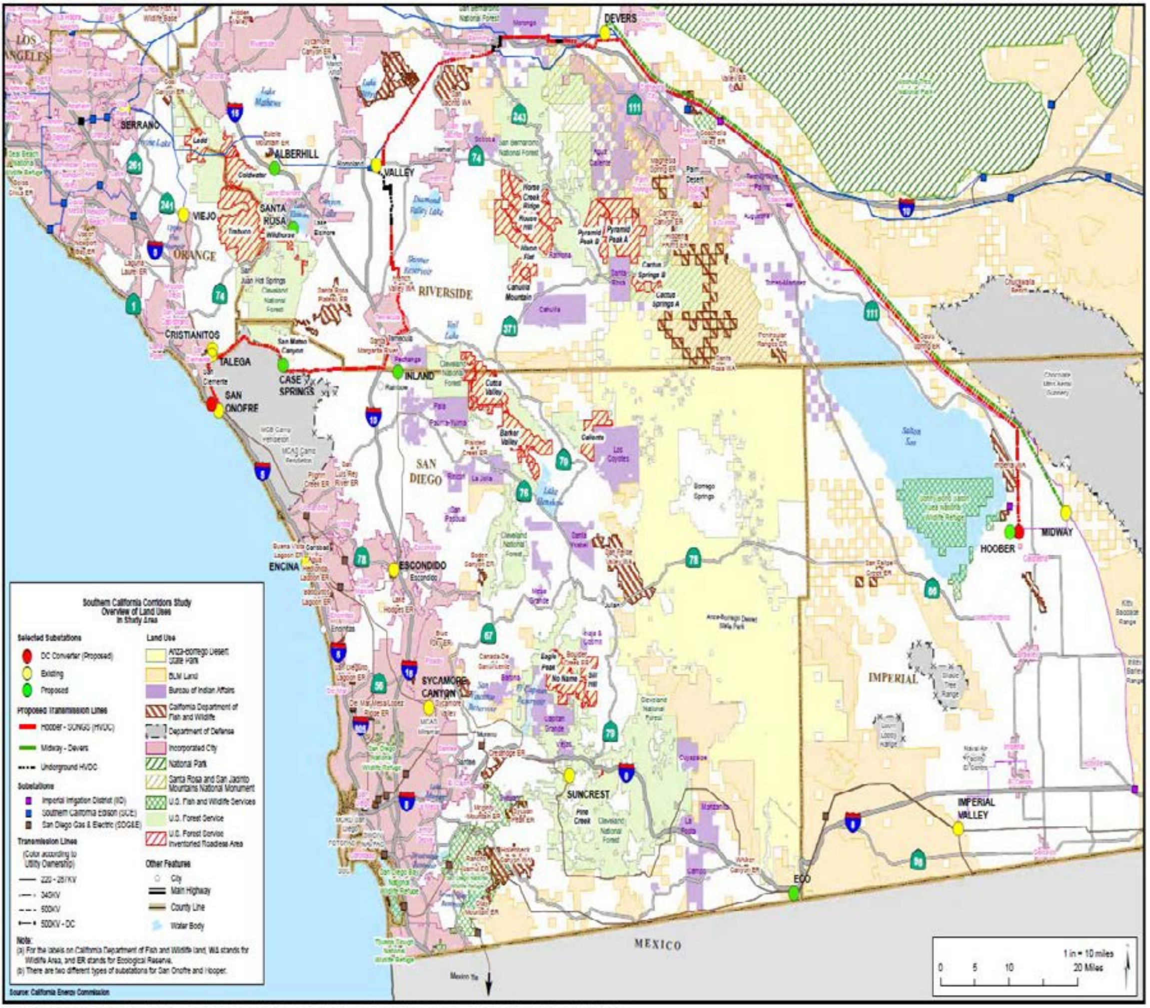
Based on the powerflow and stability studies, we believe that this upgrade in conjunction with the recommended mitigations would also mitigate deliverability constraints and

- Provide deliverability for the 2500 Imperial zone sensitivity portfolio

Alternative mitigation I scope -

1. By-pass series capacitors on ECO-Miguel 500 kV and ECO-Suncrest 500 kV lines
2. Modify IV SPS to include generation tripping following Miguel 500/230 kV transformer N-1 outages
3. Rely on 30 min emergency rating of 500/230kV banks at IV and Suncrest
4. Devers – Midway 500 kV line

Deliverability Assessment Results for SDG&E Area – Alternative Mitigation II



<u>Strategic Transmission Expansion Project (STEP)</u>

Based on the powerflow and stability studies, we believe that this upgrade in conjunction with the recommended mitigations would also

- Provide deliverability for the 2500 Imperial zone sensitivity portfolio.
- Provide LCR reduction benefit for LA Basin/SDG&E area (refer to LCR discussion)

Alternative mitigation II scope -

1. By-pass series capacitors on ECO-Miguel 500 kV and ECO-Suncrest 500 kV lines
2. Modify IV SPS to include generation tripping following Miguel 500/230 kV transformer N-1 outages
3. Rely on 30 min emergency rating of 500/230kV banks at IV and Suncrest
4. STEP

Conclusions

- The recommended mitigations and approved projects largely restore overall deliverability from the Imperial area to pre-SONGS retirement levels
- Generation connecting directly to the ISO grid (operational or under construction) is relying on some of that deliverability
- A modest amount (500 MW to 750 MW) is available for future generation (ISO or IID-connected)
- Significant reinforcements will be necessary to achieve the levels tested in the information-only sensitivity portfolio

Policy Driven Planning Deliverability Assessment Results – PG&E Area

Binaya Shrestha
Senior Regional Transmission Engineer

2014-2015 Transmission Planning Process Stakeholder Meeting
November 19-20, 2014

Overview of renewable zones that impact PG&E area

Renewable Zone	Base Portfolio MW
Carrizo South	900
Merced	5
Westlands	484
NonCREZ	137
Distributed Generation – PG&E	984
Total	2,510

Deliverability Assessment Results for PG&E Area – Mendota-San Joaquin-Helm 70 kV line

Overloaded Facility	Contingency	Flow
Mendota-San Joaquin-Helm 70 kV Line	Normal	110%

Mendota-San Joaquin-Helm 70 kV Line Deliverability Constraint	
Constrained Renewable Zones	Westlands
Total Renewable MW Affected	28 MW
Deliverable MW w/o Mitigation	25 MW
Mitigation	Local constraint to be addressed in generation interconnection

Deliverability Assessment Results for PG&E Area – Coburn 230/60 kV Transformer #2

Overloaded Facility	Contingency	Flow
Coburn 230/60 kV Transformer #2	Coburn 230/60 kV Transformer #1	137%

Coburn 230/60 kV Transformer #2 Deliverability Constraint	
Constrained Renewable Zones	Coburn Area (60 kV) PG&E DG
Total Renewable MW Affected	28 MW
Deliverable MW w/o Mitigation	0 MW
Mitigation	Local constraint to be addressed in generation interconnection

Deliverability Assessment Results for PG&E Area – Arco-Carneras 70 kV Line

Overloaded Facility	Contingency	Flow
Arco-Carneras 70 kV Line	Carneras-Taft 70 kV Line	107%

Arco-Carneras 70 kV Line Deliverability Constraint	
Constrained Renewable Zones	Westlands and PG&E DG
Total Renewable MW Affected	56 MW
Deliverable MW w/o Mitigation	53 MW
Mitigation	Local constraint to be addressed in generation interconnection

Deliverability Assessment Results for PG&E Area – Fellows-Taft 115 kV Line

Overloaded Facility	Contingency	Flow
Fellows-Taft 115 kV Line	Midway-Taft 115 kV Line	105%

Fellows-Taft 115 kV Line Deliverability Constraint	
Constrained Renewable Zones	Kern Area (115 kV) and PG&E DG
Total Renewable MW Affected	82 MW
Deliverable MW w/o Mitigation	76 MW
Mitigation	Local constraint to be addressed in generation interconnection

Deliverability Assessment Results for PG&E Area – Delevan-Cortina 230 kV line

Overloaded Facility	Contingency	Flow
Delevan-Cortina 230 kV Line	Delevan-Vaca Dixon No.2 230 kV Line and Delevan-Vaca Dixon No.3 230 kV Line	104%

Delevan-Cortina 230 kV Line Deliverability Constraint	
Constrained Renewable Zones	Cottonwood Area (115 kV)
Total Renewable MW Affected	40 MW
Deliverable MW w/o Mitigation	0 MW
Mitigation	Under evaluation

PG&E Area Policy Driven Powerflow and Stability Results

Irina Green
Regional Transmission Engineer Lead

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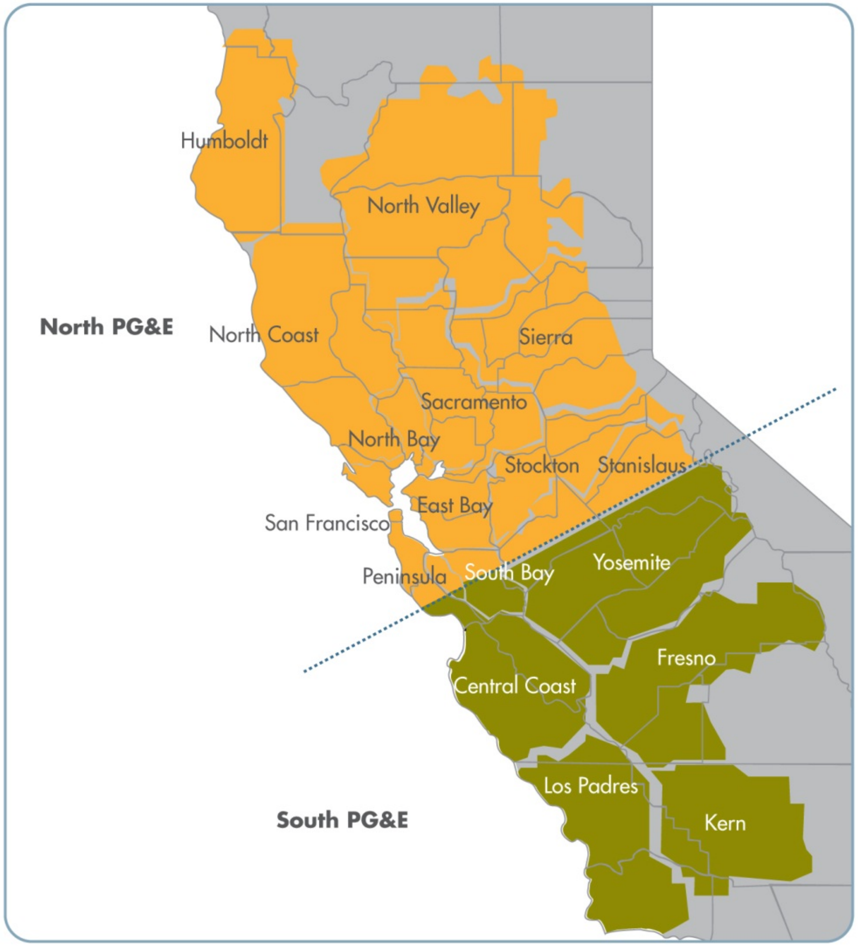
PG&E Area



	Planning Areas	Renewable Zones
PG&E North	Humboldt North Coast/North Bay Greater Bay Area North Valley Central Valley	
PG&E South	Central Coast /Los Padres Yosemite Fresno Kern	Carrizo South Merced Westlands

Portfolio	Capacity
Commercial Interest (Base)	2,509 MW
High DG	4,275 MW

Studies Performed

- **Bulk System Studies**
  - Post-transient and transient stability analysis for both portfolios
  - Peak conditions
  - All single and double 500 kV outages studied, large generation outages, three-phase faults with normal clearing, single-phase-to-ground faults with delayed clearing
- **Local Area Studies**
  - Thermal, voltage and transient stability studies for all three portfolios
  - Peak conditions
  - All Category, B, selected C and D contingencies

Bulk System Results

Thermal Overloads, Bulk System North PG&E

- No new or increased overloads compared with the Reliability Studies

Transient and Voltage Stability, Bulk System North PG&E

- No new concerns compared with the Reliability Studies

Flow on COI was lower than in the Reliability studies: 4195 MW in Commercial Interest case, 4173 MW in high DG case

Overload was less than in the Reliability case: fewer facilities were overloaded, and loading was lower

Thermal Overloads, Bulk System South PG&E

- No concerns in addition to those identified in the Reliability Studies

- Path 26 flow was 4000 MW both in the Commercial Interest and High DG cases

Transient Stability, Bulk System South PG&E

- No concerns in addition to those identified in the Reliability Studies

- Used new dynamic stability models for Inverter-based renewable projects

Local Areas

Humboldt Area Overview

Renewable generation modeled in Humboldt area

Humboldt	CI (MW)	HDG (MW)
DG	0	43
NonCREZ	0	0

North Coast / North Bay Area Overview

Renewable generation modeled in North Coast/North Bay area

North Coast / North Bay	CI (MW)	HDG (MW)
DG	0	349
NonCREZ	25	25

Greater Bay Area Overview

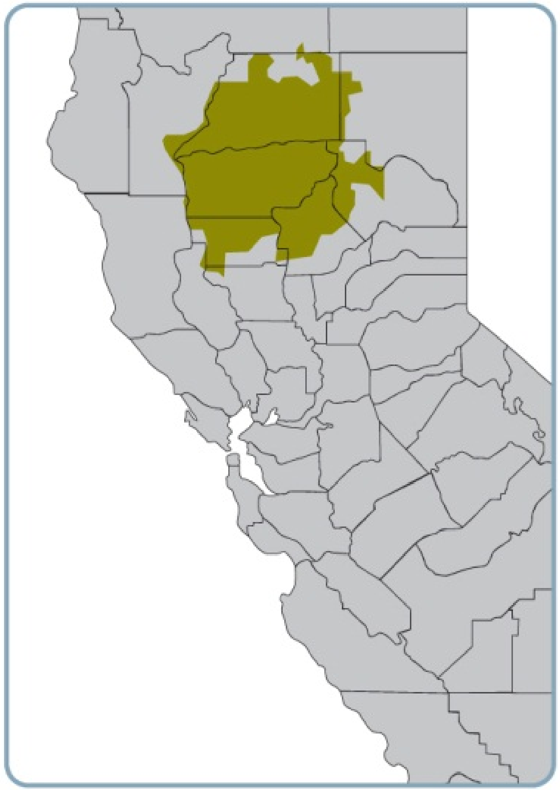
Renewable generation modeled in Greater Bay area

Greater Bay Area	CI (MW)	HDG (MW)
DG	145	812
NonCREZ	5	5

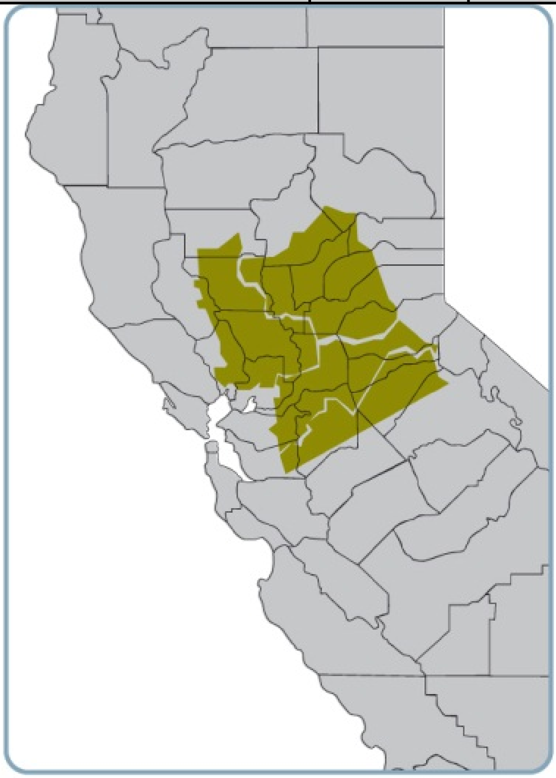
North Valley & Central Valley Area Overview

Renewable generation modeled in North Valley / Central Valley area

North Valley	CI (MW)	HDG (MW)
DG	0	314
NonCREZ	58	58



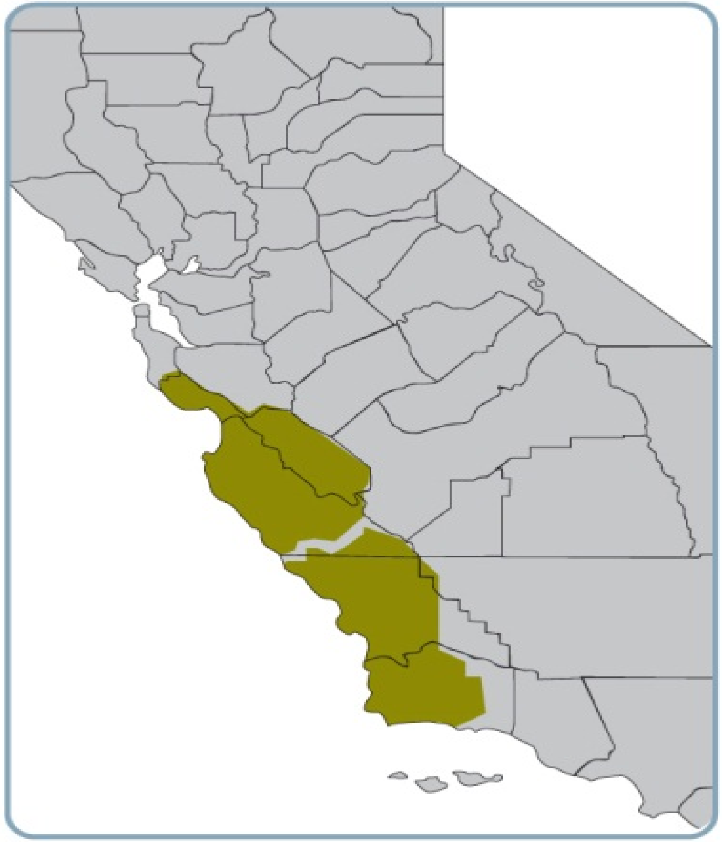
Central Valley	CI (MW)	HDG (MW)
DG	0	721
NonCREZ	49	45



California ISO
Shaping a Renewed Future

Central Coast & Los Padres Areas Overview

Renewable generation modeled in Central Coast / Los Padres area

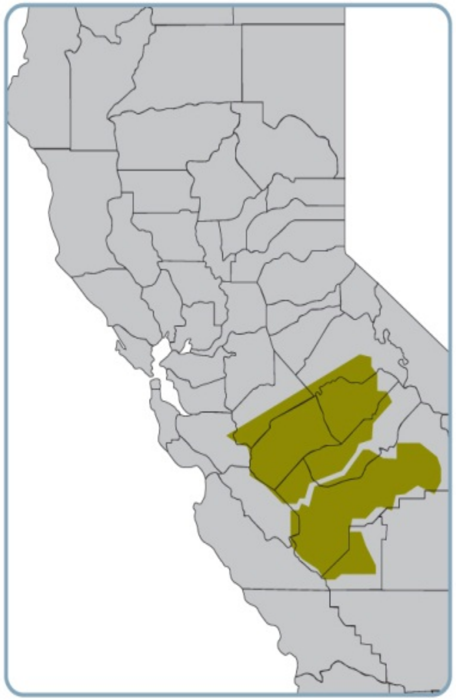


Central Coast & Los Padres	CI (MW)	HDG (MW)
DG	152	106
Carrizo South	900	406

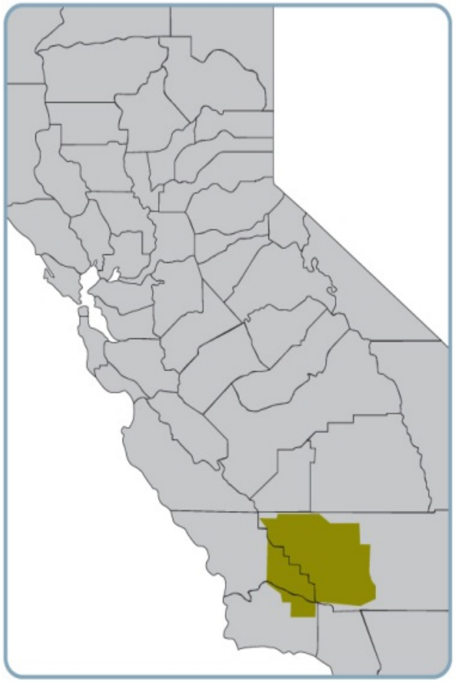
Fresno & Kern Area Overview

Renewable generation modeled in Fresno/Kern areas

Fresno	CI (MW)	HDG (MW)
DG	360	685
Merced	5	5
Westlands	484	389



Kern	CI (MW)	HDG (MW)
DG	326	372



Local Areas – Summer Peak Results

- **No thermal overloads** in addition to those identified in the Reliability Studies
- **No additional voltage concerns** in addition to those identified in the Reliability Studies

Summary of LA Basin/San Diego and Imperial area interaction

Robert Sparks
Manager Regional Transmission - South

2014-2015 Transmission Planning Process Stakeholder Meeting
November 19-20, 2014

Complex interaction between LA Basin/San Diego reliability needs and Imperial area deliverability:

- LA Basin/San Diego reliability needs (LCR analysis):
  - Approved transmission and authorized procurement meet needs, however…
  - We need to consider backup or alternative plans due to the considerable uncertainty over the ultimate success of procurement of authorized preferred resources and other forecast assumptions.
- Imperial Area deliverability
  - Approved transmission and recommended mitigations restore overall <u>forecast</u> deliverability to the area to pre-SONGS retirement levels, however,
  - Potential further development may exceed remaining forecast deliverability after considering projects already moving forward in ISO and in IID.

Various options provide a blend of benefits:

- Options have been explored for informational purposes focusing on each issue in turn, then assessing the benefits they provide to the other.
- Some reinforcements improve LA Basin/San Diego needs (Group 2 type projects), but provide little benefit to improving deliverability from the Imperial area
- Others provide the Imperial area deliverability benefits but little local capacity benefit.
- Larger more comprehensive solutions have also been proposed (STEP)
- Combination of individual solutions that each provide specific benefits must also be considered

Other considerations must also be taken into account in considering backup plans:

- Timing and emergence of need for additional mitigation for one or both potential needs.
- Feasibility of various developments (drawing on Imperial area consultation efforts and the CEC/Aspen high-level environmental assessment analysis).
- These factors favor a more staged approach:
  - Projects that work well together but are not fully dependent on the other project proceeding, such as Midway-Devers 50 kV AC or DC, and Valley-Talega 500 kV
- Further analysis will be required as needs evolve, including consideration of a larger picture that benefits both California and Mexico clean energy objectives
  - e.g. CFE – ISO Bulk 500 kV or HVDC Transmission

Harry Allen-Eldorado 500 kV line Economic Benefit Analysis

Robert Sparks
Manager Regional Transmission - South

Transmission Planning Process Stakeholder Meeting
November 19-20, 2014

Contents

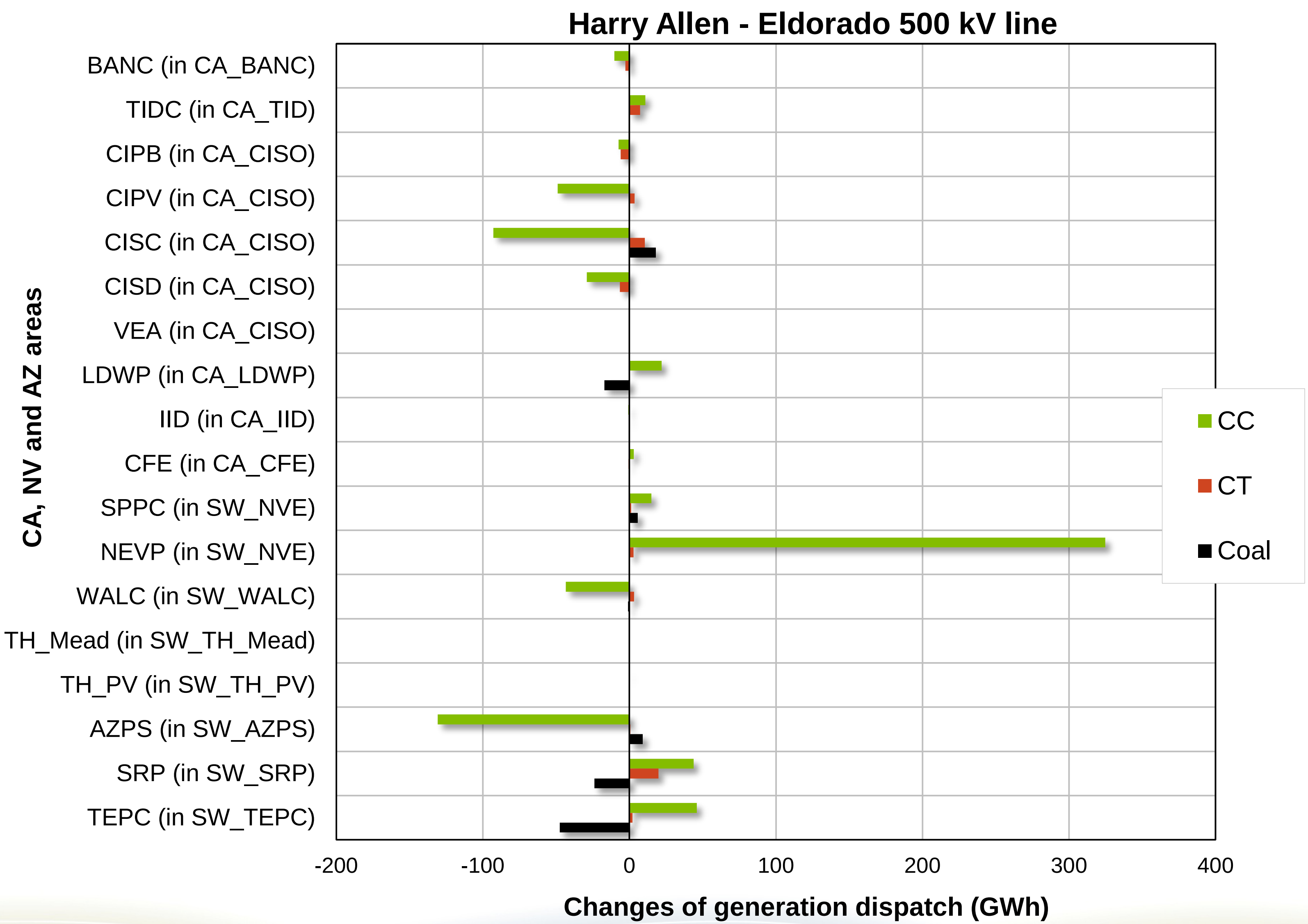
- Benefits Assessment to Date
  - Economic Dispatch Savings
  - Capacity Savings
- Present Value Analysis of Line
  - Present Value of Benefits over 50 years
  - Revenue Requirement Calculation
  - Benefit-Cost Ratio by Scenario

Harry Allen-El Dorado 500 kV project evaluation – 2024 base case

- 2019 and 2024 Gridview Base Cases:
  - TEPPC 2024 V1.0 (8/1/2014) used as a starting case
  - Updated as described in Luba Kravchuk's September 24, 2014 stakeholder presentation

Incremental changes of generation dispatch

With addition of the Harry Allen-Eldorado 500 kV line



Simulation year 2023

Determination of yearly production benefits

With addition of the Harry Allen-Eldorado 500 kV line

Year	Total Benefits		Consumer	Producer	Transmission
2019	$9.4M	=	$12.7M	-$2.9M	-$0.4M
2024	$8.5M	=	$10M	-$1.8M	$0.3M

$\underbrace{\text{Consumer} \quad \text{Producer} \quad \text{Transmission}}$

Computed by GridView production simulation for 8,760 hours in each study year by comparison of “pre-project” and “post-project” cases

Economic Dispatch Savings: Current Base Cases

- Current GridView base cases show the following annual TEAM benefits from adding Harry Allen-Eldorado Line (all values in 2014$):
  - In 2019: **$9.4 million**
  - In 2024: **$8.5 million**
- Savings largely driven by reduction in LMPs in SCE, slightly offset by reductions in UOG profits
  - Dispatch changes largely from INCs on NVE CCGTs, DECs on CCGTs in CAISO & slightly lower CA imports from other areas

Sensitivity Analysis

	Total Benefits ($M)
2024 Base Case	8.5
Sensitivity analyses	
Load - High (+6% above forecast)	15
Load - Low (-6% below forecast)	3
Natural gas prices - High (+25%)	13
Natural gas prices - Low (-25%)	9
CA RPS 33% portfolio - #2 (Sensitivity)	11
CA RPS 33% portfolio - #3 (High DG)	0
Flexible reserve - High (+25%)	13
Flexible reserve - Low (-25%)	9

The ISO continues to refine incorporation of the EIM into its transmission planning model and planning analysis.

Import Capacity Benefit Evaluation

- Assessed the transfer capability on Path 46 with and without Harry Allen-Eldorado 500 kV line project
- Studies on CAISO’s 2014/2015 TPP 2024 summer peak base case with 33% RPS base portfolio
- Assessed capacity price differences between Desert Southwest and California
- Estimated capacity cost benefits based on incremental increase in Path 46 transfer capability and capacity price difference

Simulation results

H Allen - El Dorado	WOR flow	Incremental Capacity	Critical contingency	Limiting constraint	Percentage
Not modeled	10178		Devers - RedBluff N-2	Mead-Marketplace	99.92%
Modeled 70% s-cap	10380	202	Devers - RedBluff N-2	Victorville-Lugo	99.94%

Starting from 2024 Policy driven power flow basecase with Commercial Interest portfolio

Capacity Benefits of Harry Allen-Eldorado Line

- Capacity benefit analysis assumes load resource balance year of
  - 2020 for CA,
  - 2025 for Desert Southwest
  - Consistent with TPP’s 2013-14 planning cycle
  - Small updates to CT value, dollar year, etc.

- This results in **$10.2M** in annual capacity savings based on 200 MW of increased import capacity

Present Value of Gross Savings

- Interpolating 2019 and 2024 analysis and assumed to grow at rate of inflation (constant real savings after 2024)
- Benefits calculate for 50 year period (2020-2069), discounted at
  - 7% real discount rate = **$263M** in present value benefits in 2020 (project in-service year)
    - $122M in energy savings
    - $141M in capacity savings
  - 5% real discount rate = **$339M** in present value benefits in 2020
    - $160M in energy savings
    - $179M in capacity savings

Present Value of Revenue Requirement for Harry Allen-Eldorado Line

- Capital Costs assumptions for line (in 2014$)
  - $182M cost, including series caps & 10% contingency

- Present value of revenue requirement (50 year horizon, 2020-2069), discounted at:
  - 7% real discount rate = **$248M** present value cost in 2020
  - 5% real discount rate = **$297M** in present value cost in 2020

- Revenue requirement assumptions
  - 10% ROE, 7% state income tax

Calculation of benefit to cost ratio (BCR) for line – All values are Present Value to 2020 in-service year

Assumptions	5% Real Discount Rate	7% Real Discount Rate
Dispatch Benefits	$160	$122
Capacity Benefits	$179	$141
Total Gross Benefits	**$339**	**$263**
Revenue Requirement for line	**$297**	**$248**
BCR	**1.143**	**1.063**

Economic Planning Studies Preliminary Results

2014-2015 Transmission Planning Process Stakeholder Meeting

Yi Zhang

Regional Transmission Engineering Lead

November 19-20, 2014

Database development

Category	Type	2024	2019
Starting database		TEPPC 2024 V1.0 (8/1/2014)	CAISO 2024 database
Load	In-state load	CEC 2013 IEPR with AAEE forecast for 2024	CEC 2013 IEPR with AAEE forecast for 2019
	Out-of-state load	Latest WECC LRS 2012 forecast for 2024	Latest WECC LRS 2012 forecast for 2019
	Load profiles	TEPPC profiles plus CPUC profiles for DG	TEPPC profiles plus CPUC profiles for DG
	Load distribution	Four seasonal load distribution patterns	Four seasonal load distribution patterns
Generation	RPS	CPUC/CEC 2014 RPS portfolios	CPUC/CEC 2014 RPS portfolios - removed resources with in-service dates after 2019
	Once-Thru-Cooling	ISO 2014 Unified Study Assumptions	ISO 2014 Unified Study Assumptions
	Natural gas units	ISO 2014 Unified Study Assumptions	ISO 2014 Unified Study Assumptions
	Natural gas prices	CEC 2013 IEPR final (2024)	CEC 2013 IEPR final (2019)
	Other fuel prices	TEPPC fuel prices	TEPPC fuel prices
	GHG prices	CEC 2013 IEPR final (2024)	CEC 2013 IEPR final (2019)
Transmission	Reliability upgrades	Already-approved projects	Already-approved projects
	Policy upgrades	Already-approved projects	Already-approved projects
	Economic upgrades	Delany - Colorado River 500 kV line	No
Other models	PacifiCorp-ISO EIM	Modeled	Modeled
	NVE-ISO EIM	Modeled	Modeled

Summary of congestions

	2019		2024		
Constraints Name	***Costs (K$)***	***Duration (Hrs)***	***Costs (K$)***	***Duration (Hrs)***	***Average cost***
Path 26	2,259	297	3,244	242	2,752
BARRE-LEWIS 230 kV line	2,890	163	-	-	1,445
LEWIS-VILLA PK 230 kV line	1,637	82	-	-	818
CC SUB-C.COSTA 230 kV line #1	691	473	773	368	732
Path 15 Corridor (Path 15, Midway - Gates 500 kV and 230 kV lines)	200	24	808	38	504
P24 PG&E-Sierra	190	437	184	365	187
WESTLEY-LOSBANOS 230 kV line	73	26	232	34	152
J.HINDS-MIRAGE 230 kV line #1	3	6	290	31	146
LODI-EIGHT MI 230 kV line #1	51	67	201	194	126
MARBLE 60.0/69.0 kV transformer #1	1	34	168	1,205	84
Path 45	112	419	47	906	79
P25 PacifiCorp/PG&E 115 kV Interconnection	-	-	71	296	35
INYO 115/115 kV transformer #1	25	23	39	41	32
MAGUNDEN-PASTORIA 230 kV line #2	6	2	-	-	3
COI	3	2	-	-	1
VACA-DIX-TESLA 500 kV line #1	2	1	-	-	1
WARNERVL-WILSON 230 kV line	0	1	-	-	0

Top 5 congestions of 2014~2015 planning cycle

	2019		2024		
Constraints Name	***Costs (K$)***	***Duration (Hrs)***	***Costs (K$)***	***Duration (Hrs)***	***Average cost***
Path 26	2,259	297	3,244	242	2,752
CC SUB-C.COSTA 230 kV line #1	691	473	773	368	732
Path 15 Corridor (Path 15, Midway - Gates 500 kV and 230 kV lines)	200	24	808	38	504
WESTLEY-LOSBANOS 230 kV line	73	26	232	34	152
LODI-EIGHT MI 230 kV line #1	51	67	201	194	126

Previous cycles' top 5 congestions

	2011~2012	2012~2013	2013~2014
1	Path 26 (Northern-Southern California)	Path 26 (Northern-Southern California)	Path 26 (Northern-Southern California)
2	Greater Fresno Area (GFA)	Los Banos North (LBN)	North of Lugo (Kramer – Lugo 230 kV)
3	Greater Bay Area (GBA)	Path 61 (Lugo-Victorville)	North of Lugo (Inyo 115 kV)
4	Los Banos North (LBN)	Central California Area (CCA)	SCIT limits
5	Path 60 (Inyo-Control 115 kV tie)	Kramer area	LA metro area

- Highlighted previous top 5 also in this cycle's top 5
- No economic justifications for network upgrades were identified for congestions on Path 26, GBA, and LBN in previous cycles
- Reliability upgrades were approved in previous cycles in CCA, congestions still observed (Path 15 corridor) in this cycle
- Detail study is conducted for congestion on Lodi – Eight Miles in this cycle

Economic assessment for mitigating congestion on Lodi – Eight Miles 230 kV line

Binaya Shrestha
Senior Regional Transmission Engineer

2014-2015 Transmission Planning Process Stakeholder Meeting
November 19-20, 2014

Simulation results - congestions

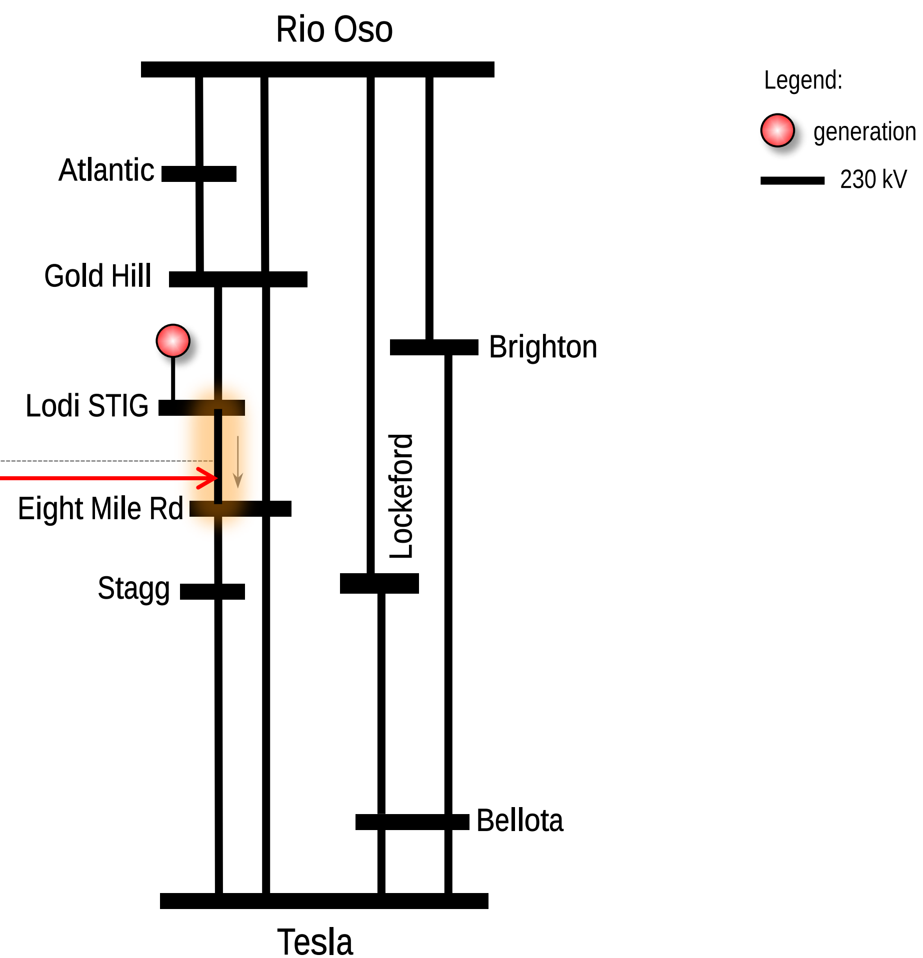
<u>Limiting constraints</u>:
Normal Condition

<u>Limiting elements</u>:
Lodi – Eight Mile 230 kV line conductor

Congestion hours

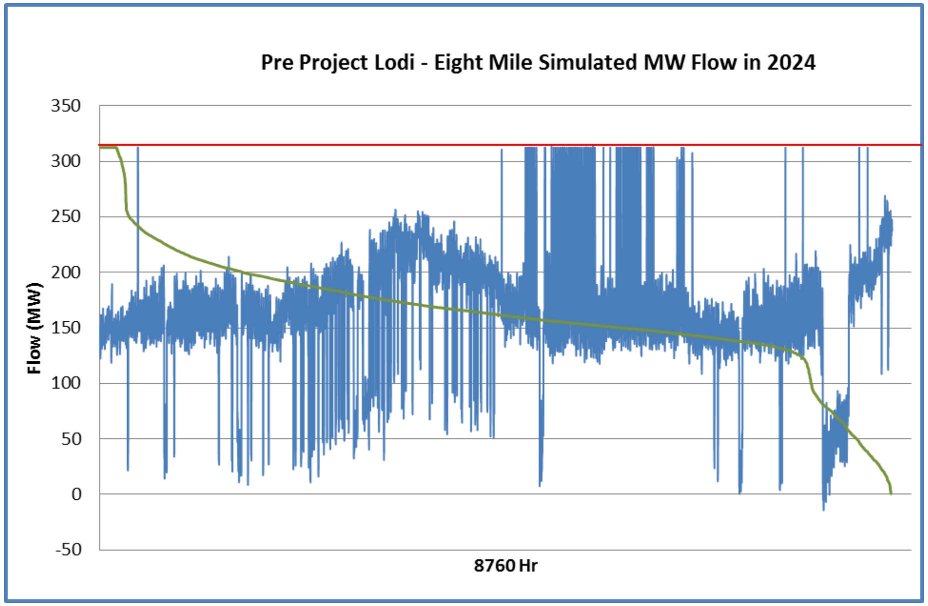
2019	2024
67	194

Reconductor Cost: $6.5M

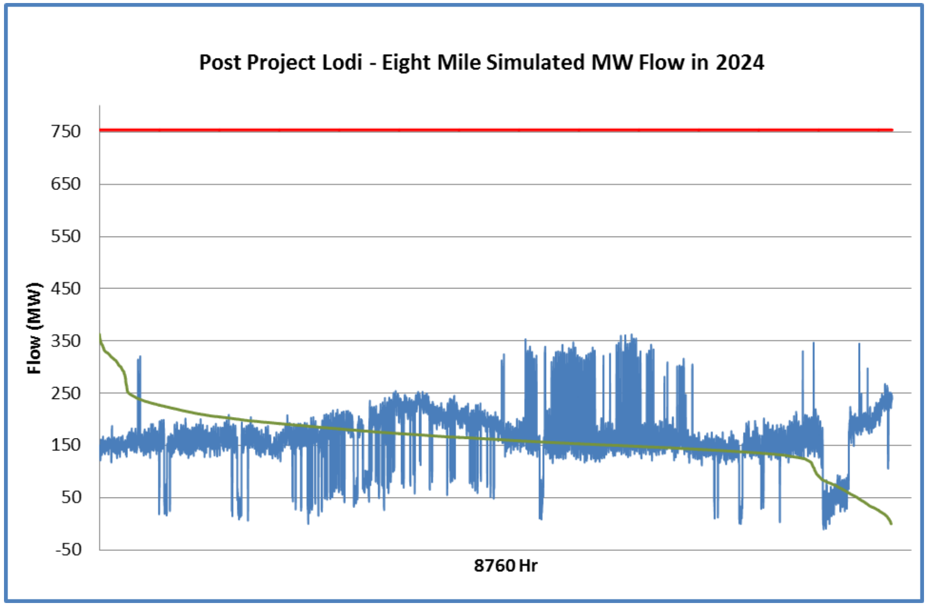


Simulation results
Power flow on Lodi – Eight Mile 230 kV Line in 2024

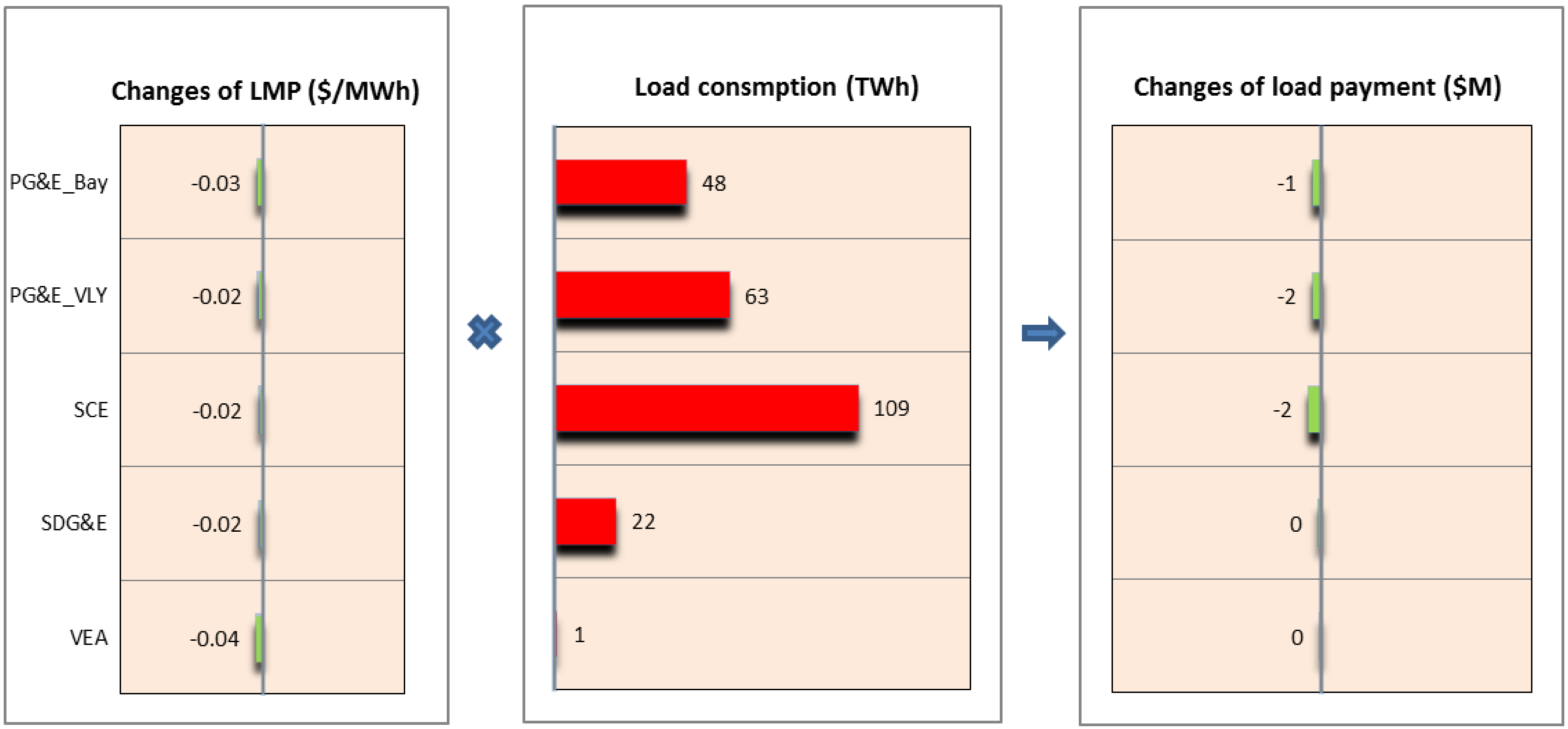
Pre Project



Post Project



Load payment reductions in the ISO-controlled grid With upgrade of Lodi – Eight Mile 230 kV Line



Simulation year 2024

The “Changes of LMP ($/MWh)” is the difference of annual averages

Determination of yearly production benefits With upgrade of Lodi-Eight Mile 230 kV Line

Year	Production		Part 1		Part 2
2019	$4M	=	$4M	+	$0M
2024	$3M	=	$3M	+	$0M

Where:

Part 1		Consumer	Producer	Transmission
$4M	=	$3M	$1M	$0M
$3M	=	$3M	$0M	$0M

Computed by GridView production simulation for 8,760 hours in each study year by comparison of "pre-project" and "post-project" cases

Part 2		Losses reduction benefit
$0M	=	~0 MW * 8760 hours * $42.19/MWh

Losses reduction estimated

Average LMP in 2024 in PG&E Valley area

Cost-benefit analysis
Upgrade Lodi-Eight Mile 230 kV Line

Million US$

	2019	2020	2021	2022	2023	2024	2025	2026	20xx
Production benefit	4	4	4	3	3	3	3	3	...
Capacity benefit	-	-	-	-	-	-	-	-	...
Total yearly benefit	4	4	4	3	3	3	3	3	...

Assumed operation year →	2019
Total benefit Sum of discounted yearly benefits	42
Total cost Total revenue requirement	10

Note: assume the economic life of the upgraded transmission facilities is 40 years

7	Capital cost

Net benefit	32
Benefit-cost ratio	3.2

Summary of preliminary results
Evaluation of economic benefits to the ISO ratepayers

ID	Proposed congestion mitigation measures			Economic assessment		
	Alt	Transmission Facilities	Op.Yr	Benefit	Cost	Comment
PGV	1	Lodi – Eight Mile 230 kV line reconductor	2019	~42M	$10M	Appears economic

Note:
The US dollars are in year 2014 values
The benefits and costs are valued at the proposed operation year
The "benefit" is the total economic benefit determined by the economic planning study
The "cost" is the total capital cost

Exclamation:
The current results are preliminary and subject to change. Going forward, when further modeling enhancements are made and open issues are resolved, it is possible that some results may differ significantly from the preliminary findings

CAISO Long Term Congestion Revenue Rights Simultaneous Feasibility Test

CAISO Area

2014-2015 ISO Transmission Planning Process

Chris Mensah-Bonsu, PhD
Sr. Regional Transmission Engineer
November 19-20, 2014

Objectives

- CAISO is required by tariff to perform the Congestion Revenue Rights (CRR) Simultaneous Feasibility Test (SFT) as part of its annual Transmission Planning Process (TPP)

- To ensure that existing LT CRRs remain feasible over their full term

  - ✓ Long-Term CRR (LTCRR) has a 10-year term

Study Assumptions

- Based on the CAISO Tariff and BPM for Transmission Planning Process (TPP)
  - ✓ Existing Long-Term CRRs must be feasible
- Transmission Assumptions
  - ✓ Transmission projects and element are considered
  - ✓ Projects must not adversely impact LTCRRs
- Market Data and Systems
  - ✓ Scheduling locations and price nodes
  - ✓ Full Network Model
  - ✓ CRR suite of applications

Study Scenarios

- Six market scenarios reflecting seasonal and time-of-use conditions are considered
  - ✓ Four (4) seasons
  - ✓ On-peak and off-peak conditions

Conclusions

- In compliance with Section 24.4.6.4 of the ISO tariff, ISO followed the LTCRR SFT study steps outlined in Section 4.2.2 of the BPM for TPP in order to determine whether, there are any existing released LTCRRs that could be "at risk" and for which appropriate mitigation measures should be developed

- Based on the results of this analysis, the ISO has determined that there are:
  - ✓ No existing released LT CRRs "at-risk"

Wrap-Up

2014-2015 Transmission Planning Process Stakeholder Meeting

Tom Cuccia
Lead Stakeholder Engagement and Policy Specialist
November 19-20, 2014

Next Steps

Date	Milestone
November 20 – December 4	Stakeholder comments to be submitted to regionaltransmission@caiso.com
January 2015	2014-2015 Draft Transmission Plan posted
February 2015	Stakeholder Meeting on contents of draft Transmission Plan