Opening

2013/2014 Transmission Planning Process Stakeholder Meeting

Tom Cuccia
Sr. Stakeholder Engagement and Policy Specialist
November 20-21, 2013

Today's Agenda – November 20th

Topic	Presenter
Opening	Tom Cuccia
Introduction & Overview	Neil Millar
RPS Portfolio Assessment	ISO Regional Transmission Engineers
Economic Planning Assessment	Xiaobo Wang
Delaney-Colorado River Incremental Capacity Assessment	Yi Zhang

Tomorrow's Agenda – November 21st

Topic	Presenter
Opening	Tom Cuccia
Recommendations for Management Approval of Reliability Projects less than $50 Million	ISO Regional Transmission Engineers
Long-Term CRR Simultaneous Feasibility Test	Chris Mensah-Bonsu

California ISO
Shaping a Renewed Future

Introduction and Overview
Policy-Driven and Economic Assessment

Neil Millar
Executive Director, Infrastructure Development

2013/2014 Transmission Planning Process Stakeholder Meeting
November 20-21, 2013

2013/2014 Transmission Planning Cycle

April 2013 — **March 2014** — **October 2014**

Coordination of Conceptual Statewide Plan

ISO Board Approval of Transmission Plan

Phase 1

Development of ISO unified planning assumptions and study plan

- **Incorporates State and Federal policy requirements and directives**
- **Demand forecasts, energy efficiency, demand response**
- **Renewable and conventional generation additions and retirements**
- **Input from stakeholders**
- **Ongoing stakeholder meetings**

Phase 2

Technical Studies and Board Approval

- **Reliability analysis**
- **Renewable delivery analysis**
- **Economic analysis**
- **Wrap up of studies continued from previous cycle**
- **Publish comprehensive transmission plan**
- **ISO Board approval**

Phase 3

Receive proposals to build identified reliability, policy and economic transmission projects.

Continued regional and sub-regional coordination

Development of 2013/2014 Annual Transmission Plan

Reliability Analysis
(NERC Compliance)

33% RPS Portfolio Analysis
- **Incorporate GIP network upgrades**
- **Identify policy transmission needs**

Economic Analysis
- **Congestion studies**
- **Identify economic transmission needs**

Other Analysis
(OTC, AB 1318)

Results

2013/2014 Ten Year Plan Milestones

- Preliminary reliability study results were posted on August 15
- Stakeholder session September 25th and 26th
- Comments received October 10
- **Today's session - preliminary policy and economic study results**
- Comments due by December 5
- Draft plan to be posted January, 2014

Issues

- Assumptions for Policy and Economic studies
- Unique challenges in this year’s policy driven analysis
- Management approval of certain reliability projects less than $50 million
- Statewide transmission plan

Renewable Portfolio Standard Policy Assumptions

- Assumptions based on additional resource production scenarios to complement the reliability analysis.
- Portfolios received from the CPUC and CEC on February 7, 2013
  - Posted to ISO website February 8
  - CPUC and CEC conducted a workshop on December 19, 2012 followed by a written comment period.
- As in 2012/2013 cycle, the “commercial interest” portfolio recommended as the base portfolio.
- Minor adjustments made to portfolios as resources were mapped into ISO cases.

Commercial Interest Portfolio (MW)

Zone	Biogas	Biomass	Geothermal	Hydro	Large Scale Solar PV	Small Solar PV	Solar Thermal	Wind	Grand Total
Alberta								450	450
Arizona					550				550
Carrizo South					900				900
Central Valley North		0			25				25
Distributed Solar - PG&E						984			984
Distributed Solar - SCE						565			565
Distributed Solar - SDGE						143			143
El Dorado					150		407		557
Imperial	15		403		1015	30		252	1715
Kramer			64		320	72	250	56	762
Los Banos					370				370
Merced	5				57				62
Mountain Pass					300		345		645
Nevada c			166						166
NonCREZ	104	52	15			2			173
Northwest								104	104
Riverside East					800	9	400		1209
Round Mountain									0
San Bernardino - Lucerne								42	42
Solano	3				30			167	200
Tehachapi	10				911	110		1070	2101
Westlands		5			108	121			233
Grand Total	136	57	648	0	5535	2034	1402	2142	11954

California ISO
Shaping a Renewed Future

Environmentally Constrained Portfolio (MW)

Zone	Biogas	Biomass	Geothermal	Hydro	Large Scale Solar PV	Small Solar PV	Solar Thermal	Wind	Grand Total
Alberta								450	450
Arizona					550				550
Carrizo South					900				900
Central Valley North		18			155				173
Distributed Solar - PG&E						1529			1529
Distributed Solar - SCE						1255			1255
Distributed Solar - SDGE						190			190
El Dorado					150		407		557
Imperial	15		30		535	30		265	875
Kramer						20	42		62
Los Banos									0
Merced	5				57				62
Mountain Pass					300		345		645
Nevada c			166						166
NonCREZ	110	180	15	21		2			328
Northwest								104	104
Riverside East					900	9	400		1309
Round Mountain		34							34
San Bernardino - Lucerne								42	42
Solano									0
Tehachapi	10				986	150		1110	2256
Westlands		5			1056	309			1370
Grand Total	139	237	211	21	5589	3494	1194	1971	12855

High Distributed Generation Portfolio (MW)

Zone	Biogas	Biomass	Geothermal	Hydro	Large Scale Solar PV	Small Solar PV	Solar Thermal	Wind	Grand Total
Alberta								450	450
Arizona					550				550
Carrizo South					300				300
Central Valley North					25				25
Distributed Solar - PG&E						3449			3449
Distributed Solar - SCE						2345			2345
Distributed Solar - SDGE						157			157
El Dorado					150		407		557
Imperial	15		30		616	30		184	875
Kramer						40	22		62
Los Banos									0
Merced	5				57				62
Mountain Pass					300		345		645
Nevada c			166						166
NonCREZ	104	52	15			2			173
Northwest								104	104
Riverside East					800	9	400		1209
Round Mountain									0
San Bernardino - Lucerne								42	42
Solano									0
Tehachapi	10				911	110		1070	2101
Westlands		5			108	121			233
Grand Total	133	57	211	0	3816	6263	1174	1850	13504

Unique challenge in this year's cycle

- Heightened reliability issues beyond OTC retirement issues:
  - Early SONGS retirement
  - Consideration of potential retirement of aging thermal generation
  - Enhanced consideration of preferred resources
- Consequences:
  - Uncertainty of potential reliability mitigations makes analysis of policy-driven needs more challenging
  - Analysis assumed local resources meet local needs – and reconsideration will be necessary depending on reliability mitigations that are ultimately selected.

Management is considering approving a number of reliability transmission projects less than $50 million

- Approving these projects allows streamlining the review and approval process of the annual transmission plan in March
- Only those projects less than $50 million are considered for management approval that:
  - Can reasonably be addressed on a standalone basis
  - Are not impacted by policy or economic issues that are still being assessed.
  - Are not impacted by the approval of the transmission plan (and reliability projects over $50 million) by the Board of Governors in March, 2014
- Management will only approve these projects after the December Board of Governors meeting
- Other projects less than $50 million will be dealt with in the approval of the comprehensive plan in March.

ISO statewide transmission plan

- Posted on October 31st
- Comment period from November 1st to November 20th
- Was developed based previous California Transmission Planning Group efforts and updated for this planning cycle with publicly available information from our neighbors' plans.

South Policy Driven Powerflow and Stability Results

2013/2014 Transmission Planning Process Stakeholder Meeting

Yi Zhang
Senior Regional Transmission Engineer
November 20-21, 2013

Study summary

- Consolidated PG&E, SCE, SDGE and VEA 2023 peak load basecases to have a system wide basecases
- Modeled 2013/2014 33% RPS base portfolio
- Modeled renewable generation output, and EOR (Path 49) flow as well, at the same level as identified in the last planning cycle
- Assumed 520 MW new generation in northwest San Diego

Observations

- The renewable generation along the borders between CA and AZ/NV is at about 70~75% of the capacity for Solar, and 90% for Geothermal
  - Import on WOR and renewable generation are stressing the transmission system
  - Upgrades or curtailment may be needed to maintain system reliability

Study results

EOR flow	WOR flow	SCIT flow	Critical contingency	Limiting Components	Flow or voltage or voltage dip
5000	10730	16206	IV-ECO N-1 with SPS, ECO-Miguel with SPS , and WITHOUT cross-tripping	TJI-230 to OtayMesa 230 kV line	105%
			IV-ECO N-1 with SPS, ECO-Miguel with SPS, and WITH cross-tripping	Suncrest – Sycamore 230 kV lines #1 and #2 Suncrest 230 and 500 kV buses voltage dip	110.1% 7%
			Basecase	Miguel – BayBlvd 230 kV line	102%

Commercial Interest Portfolio – South

Sum of CommInt MW							
Row Labels	**Biogas**	**Geothermal**	**Large Scale Solar PV**	**Small Solar PV**	**Solar Thermal**	**Wind**	**Grand Total**
Arizona			550				550
Distributed Solar - SCE				565			565
Distributed Solar - SDGE				143			143
El Dorado			150		407		557
Imperial	15	403	1015	30		252	1715
Kramer		64	320	72	250	56	762
Mountain Pass			300		345		645
Nevada C		50					50
NonCrez	99						99
Riverside East			800	9	400		1209
San Bernardino - Lucerne						42	42
Tehachapi	10		911	110		1070	2101
Grand Total	**124**	**517**	**4046**	**928**	**1402**	**1420**	**8438**

Environmental Constrained Portfolio - South

Sum of Env MW							
Row Labels	**Biogas**	**Geothermal**	**Large Scale Solar PV**	**Small Solar PV**	**Solar Thermal**	**Wind**	**Grand Total**
Arizona			550				550
Distributed Solar - SCE				1255			1255
Distributed Solar - SDGE				190			190
El Dorado			150		407		557
Imperial	15	30	535	30		265	875
Kramer				20	42		62
Mountain Pass			300		345		645
Nevada C		50					50
NonCrez	105						105
Riverside East			900	9	400		1309
San Bernardino - Lucerne						42	42
Tehachapi	10		986	150		1110	2256
Grand Total	**130**	**80**	**3421**	**1654**	**1194**	**1417**	**7896**

California ISO
Shaping a Renewed Future

High DG Portfolio - South

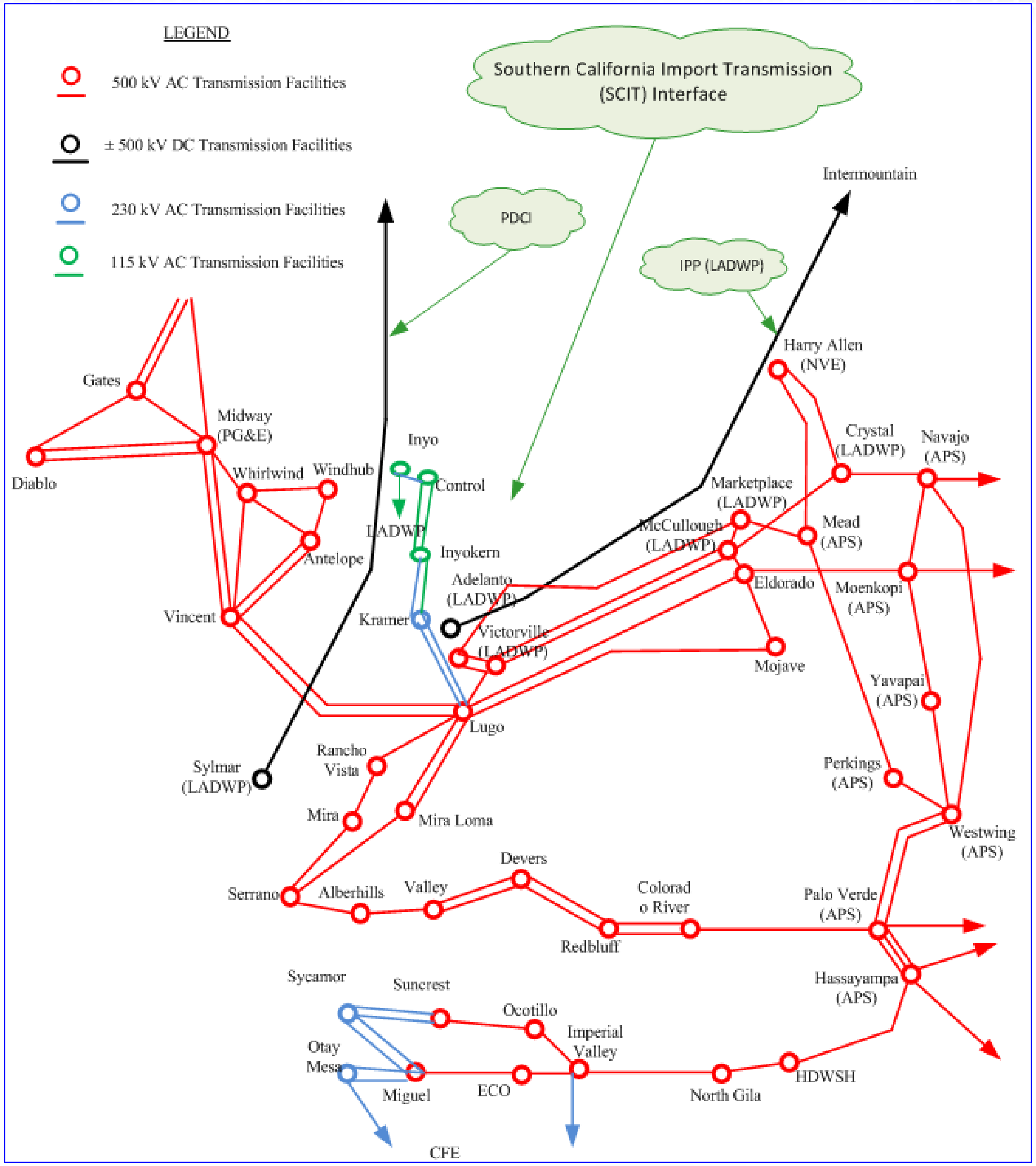
Sum of HDG MW							
Row Labels	**Biogas**	**Geothermal**	**Large Scale Solar PV**	**Small Solar PV**	**Solar Thermal**	**Wind**	**Grand Total**
Arizona			550				550
Distributed Solar - SCE				2345			2345
Distributed Solar - SDGE				157			157
El Dorado			150		407		557
Imperial	15	30	616	30		184	875
Kramer				40	22		62
Mountain Pass			300		345		645
Nevada C		50					50
NonCrez	99						99
Riverside East			800	9	400		1209
San Bernardino - Lucerne						42	42
Tehachapi	10		911	110		1070	2101
Grand Total	**124**	**80**	**3327**	**2691**	**1174**	**1296**	**8692**

Comparison of three portfolios

Zone	CI (MW)	EC (MW)	HDG (MW)
Arizona	550	550	550
Distributed Solar - SCE	565	1255	2345
Distributed Solar - SDGE	143	190	157
El Dorado	557	557	557
Imperial (IID)	867	225	225
Imperial (SDGE)	848	650	650
Kramer	762	62	62
Mountain Pass	645	645	645
Riverside East	1209	1309	1209
San Bernardino - Lucerne	42	42	42
Tehachapi	2101	2256	2101

Comparison of three portfolios (cont.)

- With the same WOR flow, we have the following observations in EC and HDG portfolios:
  - The stressed patterns are similar in all three portfolios
  - The flow on Inyo phase shifter would be less since there are less renewable in Kramer zone, than in CI portfolio
  - Suncrest – Sycamore 230 kV lines would still be overloaded following the same disturbance reported in Slide 6
  - Suncrest 230 kV and 500 kV buses would still have voltage dip violations following the same disturbance reported in Slide 6



LEGEND
500 kV AC Transmission Facilities
± 500 kV DC Transmission Facilities
230 kV AC Transmission Facilities
115 kV AC Transmission Facilities
Southern California Import Transmission (SCIT) Interface
PDCI
IPP (LADWP)
Intermountain
Harry Allen (NVE)
Gates
Midway (PG&E)
Diablo
Whirlwind
Windhub
Inyo
Control
LADWP
Inyokern
Antelope
Vincent
Kramer
Adelanto (LADWP)
Victorville (LADWP)
Marketplace (LADWP)
McCullough (LADWP)
Crystal (LADWP)
Navajo (APS)
Mead (APS)
Eldorado
Moenkopi (APS)
Mojave
Yavapai (APS)
Lugo
Sylmar (LADWP)
Rancho Vista
Mira
Mira Loma
Perkings (APS)
Westwing (APS)
Serrano
Alberhills
Valley
Devers
Colorad o River
Redbluff
Palo Verde (APS)
Hassayampa (APS)
Sycamor
Suncrest
Ocotillo
Imperial Valley
Otay Mesa
Miguel
ECO
North Gila
HDWSH
CFE

Preliminary recommendation of upgrades

- Category 1
  - IV/CFE flow control device and Suncrest SVC
    - Install a phase shifter between Imperial Valley 230 kV and CFE's ROA-230 230 kV buses at Imperial Valley substation
      - +/-45 degree
      - 800/1000 MVA rating
      - Estimated cost $55M based on similar proposal
    - Install 150 MVAr SVC at Suncrest 230 kV bus
      - Estimated cost $33M based on similar proposal

Note: Need to coordinate with Post-SONGS mitigation alternatives being evaluated in the reliability analysis

Preliminary recommendation of upgrades (cont.)

- As alternative to the Phase shifter/SVC upgrade
  - Upgrade Miguel – Bay Blvd to have higher normal rating
    - Estimated cost $12M based on GIP study
  - 3rd 230 kV line out of Suncrest
    - Upgrade Los Coches 138 kV to 230 kV
    - Build new 230 kV line from Suncrest to Los Coches
    - Loop Miguel-Sycamore line into Los Coches
    - Estimated cost $260M based on similar proposed project
  - 450 MVAR SVC at Suncrest 230 kV
    - about $100M

Policy Driven Planning Deliverability Assessment Assumptions

2013/2014 Transmission Planning Process Stakeholder Meeting

Songzhe Zhu
Lead Regional Transmission Engineer
November 20-21, 2013

Overview

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

Objectives of Base 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 (2014 Maximum RA Import Capability)
- Historically unused Existing Transmission Contracts are initially modeled by equivalent generators at the tie point.
- 1400 MW total import from IID between IID-SCE branch group and IID-SDGE branch group.

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 2023 1-in-5 load
- Same transmission assumptions as power flow studies.
  - Existing transmission
  - Approved transmission upgrades

Policy Driven Planning Deliverability Assessment Results – SCE Area

2013/2014 Transmission Planning Process Stakeholder Meeting

Songzhe Zhu
Lead Regional Transmission Engineer
November 20-21, 2013

Overview of renewable zones that impact SCE area

Renewable Zone	Base Portfolio MW
Arizona	550
Distributed Solar - SCE	565
Imperial	1,715
Kramer	762
Mountain Pass	645
Nevada C	50
Non-CREZ	99
Riverside East	1209
San Bernardino - Lucerne	42
Tehachapi	2,101
El Dorado	557

Deliverability Assessment Results for SCE Area – North of Inyokern

Overloaded Facility	Contingency	Flow
Inyo 115kV phase shifter	Base Case	155.73%
	Inyo - Owenscon 230 kV No. 1	176.28%
	Rinaldi - Victorville 500kV No. 1 & Rinaldi - Adelanto 500kV No. 1	166.33%
Control - Inyo 115kV No. 1	Base Case	110.72%
	Inyo - Owenscon 230 kV No. 1	129.57%
	Control - Inyokern - Coso 115kV No. 1	128.57%
	Control - Inyokern 115kV No. 1	128.36%
	Rinaldi - Victorville 500kV No. 1 & Rinaldi - Adelanto 500kV No. 1	120.41%
	Lugo - Victor 230kV No. 1 and No. 2	107.50%
	Lugo 500/230kV bank No. 1 or No. 2	103.58%
Inyo 230/115 bank No. 1 or 2	Inyo - Owenscon 230 kV No. 1	103.63%

Deliverability Assessment Results for SCE Area – North of Inyokern (Cont.)

North of Inyokern Deliverability Constraint	
Constrained Renewable Zones	Kramer (north of Ransberg); Nevada C (Control)
Total Renewable MW Affected	114.30 MW
Deliverable MW w/o Mitigation	< 20 MW
Mitigation	Upgrade Inyo phase shifter
	Local constraint to be addressed in generation interconnection

California ISO
Shaping a Renewed Future

Deliverability Assessment Results for SCE Area – Kramer A Bank

Overloaded Facility	Contingency	Flow
Kramer 230/115kV bank No. 1	Kramer - Victor 115kV No. 1 & Kramer - Victor - Roadway 115kV No. 1	119.25%
Kramer 230/115kV bank No. 2	Kramer - Victor 115kV No. 1 & Kramer - Victor - Roadway 115kV No. 1	102.81%

Kramer A Bank Deliverability Constraint	
Constrained Renewable Zones	Kramer (115kV); Nevada C (Control)
Total Renewable MW Affected	463.30 MW
Deliverable MW w/o Mitigation	< 350 MW
Mitigation	SPS tripping generation
	Local constraint to be addressed in generation interconnection

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

Overloaded Facility	Contingency	Flow
Coolwater - Tortilla - Segs2 115kV No. 1 (Tortilla leg)	Kramer - Coolwater 115kV No. 1	116.41%
Kramer - Coolwater 115kV No. 1	Coolwater - Tortilla - Segs2 115kV No. 1	109.74%

West of Coolwater 115kV Deliverability Constraint	
Constrained Renewable Zones	Kramer (Coolwater 115kV); Mountain Pass
Total Renewable MW Affected	620 MW
Deliverable MW w/o Mitigation	< 570 MW
Mitigation	SPS tripping generation
	Local constraint to be addressed in generation interconnection

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

Overloaded Facility	Contingency	Flow
Ivanpah - Mountain Pass - Baker - Dunnsiding - Coolwater 115kV No. 1	Kramer - Coolwater 115kV No. 1 & Coolwater - Tortilla - Segs2 115kV No. 1	voltage instability
	Kramer - Coolwater 115kV No. 1 & Kramer - Tortilla 115kV No. 1	voltage instability

East of Coolwater 115kV Deliverability Constraint	
Constrained Renewable Zones	Kramer (Coolwater 115kV)
Total Renewable MW Affected	230 MW
Deliverable MW w/o Mitigation	0 MW
Mitigation	SPS tripping generation
	Local constraint to be addressed in generation interconnection

Deliverability Assessment Results for SCE Area – Antelope-Neenach-Bailey

Overloaded Facility	Contingency	Flow
Antelope - Neenach 66kV	Bailey - Neenach - Westpac 66kV No. 1	180.10%
Bailey - Neenach - Westpac 66kV No. 1 (Bailey leg)	Antelope - Neenach 66kV	116.18%
Bailey - Neenach - Westpac 66kV No. 1 (Neenach leg)	Base Case	103.34%
	Antelope - Neenach 66kV	130.77%

Antelope - Neenach - Bailey Deliverability Constraint	
Constrained Renewable Zones	Tehachapi (Neenach 66kV)
Total Renewable MW Affected	128.7 MW
Deliverable MW w/o Mitigation	< 70 MW
Mitigation	Open breaker at Neenach on Antelope - Neenach 66kV line and reconductor Bailey - Neenach - Westpac 66kV line
	Local constraint to be addressed in generation interconnection

Deliverability Assessment Results for SCE Area – Julian Hinds-Mirage

Overloaded Facility	Contingency	Flow
J. Hinds – Mirage 230kV No. 1	Base Case	104.18%

Julian Hinds – Mirage Deliverability Constraint	
Constrained Renewable Zones	Riverside East (Blythe)
Deliverability Affected	Existing Blythe generators
Deliverable MW w/o Mitigation	< 475 MW
Mitigation	Re-configure generation interconnection
	Local constraint caused by renewables outside ISO BAA and to be addressed in generation interconnection

Deliverability Assessment Results for SCE Area – Desert Area

Overloaded Facility	Contingency	Flow
Market Place - Adelanto 500kV No. 1	Victorville - McCullough 500kV No. 1 & 2	101.62%
Lugo - Victorville 500kV No. 1	Lugo - Eldorado 500kV No. 1	104.22%

Deliverability Assessment Results for SCE Area – Desert Area (Cont.)

Desert Area Deliverability Constraint	
Constrained Renewable Zones	Eldorado, Mountain Pass, Riverside East, Imperial (SDG&E), Non-CREZ (Big Creek/Ventura)
Total Renewable MW Affected	3048.2 MW
Deliverable MW w/o Mitigation	1260 ~ 2840 MW
Mitigation	Upgrade series cap and terminal equipment at Mohave on Lugo - Mohave 500kV line. Operate Lugo - Mohave 500kV line at 70% compensation level.
Deliverable MW w/ Mitigation	2820 ~ 6070 MW

Policy Driven Planning Deliverability Assessment Results – SDG&E Area

2013/2014 Transmission Planning Process Stakeholder Meeting

Luba Kravchuk
Regional Transmission Engineer
November 20-21, 2013

Overview of renewable zones that impact SDG&E area

Renewable Zone	Base Portfolio MW
Arizona	550
Distributed Solar – SDG&E	143
Imperial (IID)	867
Imperial (SDGE)	848
Non-CREZ	25

Deliverability Assessment Results for SDG&E Area – Miguel-Bay Boulevard 230 kV

Overloaded Facility	Contingency	Flow
Miguel-Bay Boulevard 230 kV	Base Case	110%
	Miguel-Mission 230 kV #1 and #2	114%
	Miguel-Mission 230 kV #2 and Jamul-Telecanyon-Miguel 138 kV	104%
	Miguel-Mission 230 kV and Los Coches-Jamul 138 kV	102%
	Sycamore-Palomar 230 kV and Sycamore-Penasquitos 230 kV	108%

Deliverability Assessment Results for SDG&E Area – Miguel-Bay Boulevard 230 kV (Cont.)

Miguel-Bay Boulevard Deliverability Constraint	
Constrained Renewable Zones	Imperial
Total Renewable MW Affected	1083 MW
Deliverable MW w/o Mitigation	< 100 MW
Mitigation	• Upgrade line to mitigate normal overload – identified in GIP C3C4 • SPS to trip Otay Mesa and IV generation to mitigate contingency overloads – identified in GIP C1C2 and C3C4, need to expand to include existing Otay Mesa generation

Deliverability Assessment Results for SDG&E Area – Miguel 500/230 kV transformers

Overloaded Facility	Contingency	Flow
Miguel 500/230 kV #1	Miguel 500/230 kV #2	111%
Miguel 500/230 kV #2	Miguel 500/230 kV #1	108%

Miguel 500/230 kV Transformers Deliverability Constraint	
Constrained Renewable Zones	Imperial
Total Renewable MW Affected	1083 MW
Deliverable MW w/o Mitigation	<100 MW
Mitigation	SPS to trip generation at IV and rely on short term ratings of banks

Deliverability Assessment Results for SDG&E Area – Imperial Valley/ECO/Ocotillo

Overloaded Facility	Contingency	Flow
IV-ECO 500 kV	Suncrest-Ocotillo 500 kV	102%
	Suncrest-Sycamore 230 kV #1 and #2	102%
	Imperial Valley-Ocotillo 500 kV	101%
ECO-Miguel 500 kV	Suncrest-Ocotillo 500 kV	102%
	Suncrest-Sycamore 230 kV #1 and #2	102%
	Imperial Valley-Ocotillo 500 kV	101%
Imperial Valley-La Rosita 230 kV	ECO-Miguel 500 kV	104%
	Imperial Valley-ECO 500 kV	106%
Rumorosa-La Rosita 230 kV	Imperial Valley-ECO 500 kV	105%
	ECO-Miguel 500 kV	103%

Deliverability Assessment Results for SDG&E Area – Imperial Valley/ECO/Ocotillo (Cont.)

Overloaded Facility	Contingency	Flow
Sycamore-Suncrest 230 kV #1	Sycamore-Suncrest 230 kV #2	105%
	ECO-Miguel 500 kV	107%
	Imperial Valley-ECO 500 kV	108%
Sycamore-Suncrest 230 kV #2	Sycamore-Suncrest 230 kV #1	105%
	ECO-Miguel 500 kV	107%
	Imperial Valley-ECO 500 kV	108%

Deliverability Assessment Results for SDG&E Area – Imperial Valley/ECO/Ocotillo (Cont.)

Imperial Valley/ECO/Ocotillo Deliverability Constraint	
Constrained Renewable Zones	Imperial
Total Renewable MW Affected	1083 MW
Deliverable MW w/o Mitigation	<100 MW
Mitigation	SPS to trip generation at IV

Deliverability Assessment Results for SDG&E Area – Otay Mesa-Tijuana 230 kV

Overloaded Facility	Contingency	Flow
Otay Mesa-Tijuana 230 kV	Imperial Valley-ECO 500 kV	118%
	ECO-Miguel 500 kV	118%

Otay Mesa-Tijuana 230 kV Deliverability Constraint	
Constrained Renewable Zones	Imperial
Total Renewable MW Affected	1083 MW
Deliverable MW w/o Mitigation	<100 MW
Mitigation	SPS to trip IV generation and one of the following alternatives: • open Otay Mesa-Tijuana 230 kV line and upgrade Sycamore-Suncrest 230 kV lines • open Otay Mesa-Tijuana 230 kV line, Los Coches 230 kV upgrade and upgrade Ocotillo-Suncrest 500 kV series cap and terminal equipment • flow control device on CFE 230 kV parallel system • add more northwest San Diego generation

Deliverability Assessment Results for SDG&E Area – Encina-San Luis Rey 230 kV

Overloaded Facility	Contingency	Flow
Encina Tap-San Luis Rey 230 kV	Encina-San Luis Rey 230 kV	111%
	Encina-San Luis Rey 230 kV and Encina-Penasquitos 230 kV	109%
Encina-San Luis Rey 230 kV	Palomar-Sycamore 230 kV and Encina-San Luis Rey-Palomar 230 kV	104%
San Luis Rey 138/69 kV	Encina-San Luis Rey 230 kV and Encina-San Luis Rey-Palomar 230 kV	129%

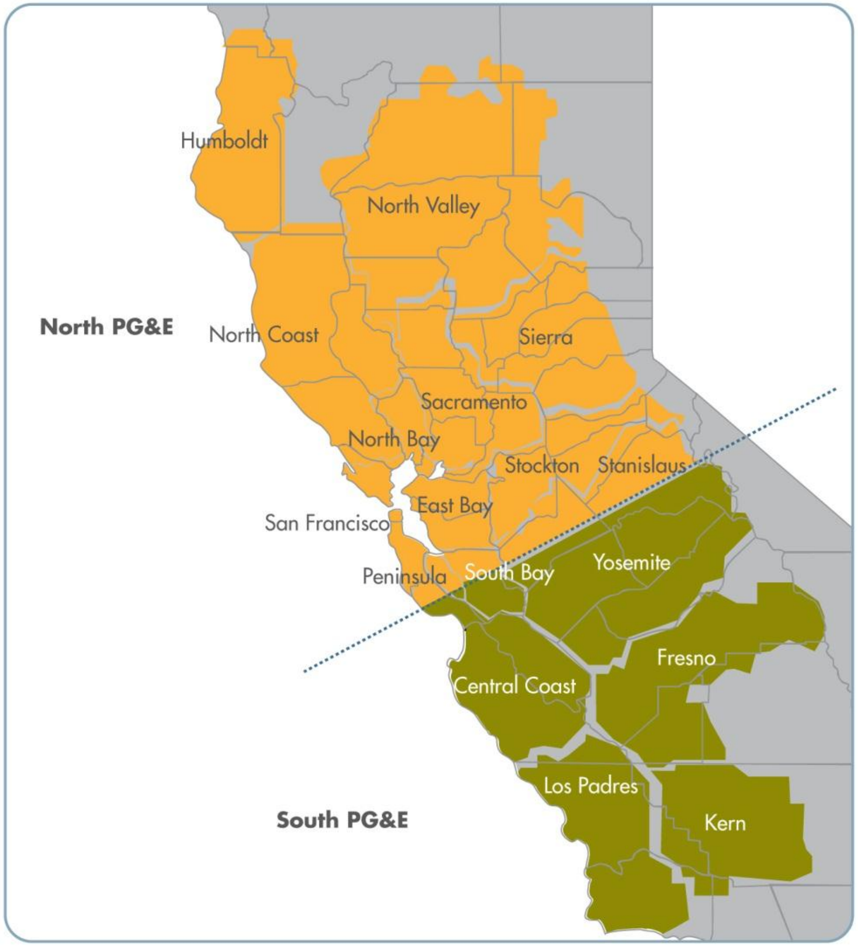
Encina-San Luis Rey 230 kV Deliverability Constraint	
Total San Diego MW Affected	6,094 MW
Deliverable MW w/o Mitigation	5,300 ~ 5,700 MW
Mitigation	• Reconductor Encina Tap-San Luis Rey 230 kV and Encina-San Luis Rey 230 kV or SPS to trip generation • SPS to trip generation to protect San Luis Rey 138/69 kV

PG&E Area Policy Driven Powerflow and Stability Results

2013/2014 Transmission Planning Process Stakeholder Meeting

Binaya Shrestha
Sr. Regional Transmission Engineer
November 20-21, 2013

PG&E Area



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

Portfolio	Capacity
Commercial Interest (Base)	2,762 MW
Environmental	4,171 MW
High DG	4,057 MW

Studies Performed

- **Bulk System Studies**
  - Post-transient and transient stability analysis for all three portfolios
  - Peak and off-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 and off-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

Thermal Overloads, Bulk System South PG&E

- Westley-Los Banos 230 kV line
  - Section between Los Banos and the new project interconnection overloaded under normal conditions, Category B and C contingencies in the Environmental Scenario in the off-peak case
  - The same section overloaded under the Category C contingency in all scenarios in the off-peak cases

- It was assumed that the section between Westley and the new project interconnection is upgraded according to the GIP studies

Transient Stability, Bulk System South PG&E

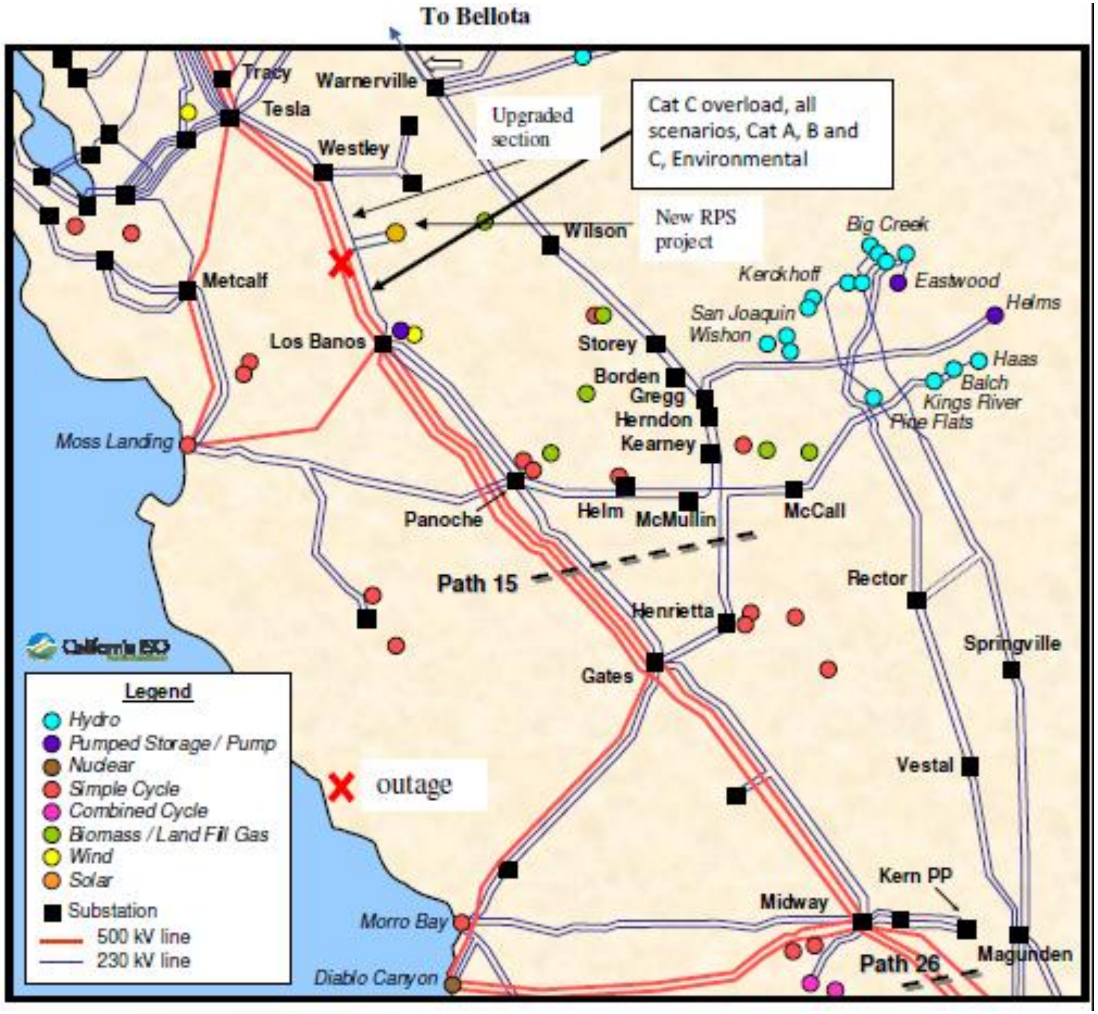
- No concerns in addition to those identified in the Reliability Studies

230 kV Line Overload in Central California – Los Banos-Westley 230 kV

- The new project will upgrade the section to Westley (in LGIP)

Mitigation of the Los Banos-RPS interconnection section

- Congestion management
- Line upgrade
- Modifying RAS for North of Los Banos 500 kV double outage may not be sufficient



Humboldt Area Results

Humboldt Area Overview

Renewable generation modeled in Humboldt area

Humboldt	CI (MW)	ENV (MW)	HDG (MW)
DG	0	0	42
NonCREZ	0	65	0

Overview of Identified Issues in Humboldt

Portfolio	Thermal Overloads		Voltage Concerns	
	Peak	Off-peak	Peak	Off-peak
Commercial Interest (Base)	0	0	0	0
Environmental	1	0	0	0
High DG	0	0	0	0

Humboldt Area – Summer Peak Results

- **Thermal Overloads**

North PG&E, Peak Load 2023, Thermal Overloads							
Humboldt Area							
Overloaded Facility	Worst Contingency	Category	Category Description	Loading (%)			Potential Mitigation
				CI	ENV	HDG	
Rio Dell – Bridgeville 60 kV Line	Humboldt – Bridgeville 115 kV Line	B	L-1	<95%	101.7%	<95%	Localized concern. Should be addressed in GIP.

- **No voltage concerns identified**

Humboldt Area – Summer Off-peak Results

- **No Off-Peak Thermal violations were identified**
- **No additional voltage concerns identified**

North Coast/North Bay Area Results

North Coast / North Bay Area Overview

Renewable generation modeled in North Coast/North Bay area

North Coast / North Bay	CI (MW)	ENV (MW)	HDG (MW)
DG	0	44	339
NonCREZ	32	95	32

Overview of Identified Issues in North Coast/North Bay

Portfolio	Thermal Overloads		Voltage Concerns	
	Peak	Off-peak	Peak	Off-peak
Commercial Interest (Base)	0	0	0	0
Environmental	0	1	0	0
High DG	0	0	0	0

North Coast / North Bay Area – Summer Peak Results

- **No Peak load thermal violations were identified.**
- **No voltage concerns identified**

Central Valley Area – Summer Off-Peak Results

- **Thermal Overloads**

North PG&E, Peak Load 2023, Thermal Overloads							
North Coast / North Bay Area							
Overloaded Facility	Worst Contingency	Category	Category Description	Loading (%)			Potential Mitigation
				CI	ENV	HDG	
Hopland Jct 115/60kV transformer	Bus Fault at Eagle Rock 115kV	C	Bus	<95%%	108.3%	32%	Localized concern. Should be addressed in GIP.

- **No voltage concerns identified**

Greater Bay Area Results

Greater Bay Area Overview

Renewable generation modeled in Greater Bay area

Greater Bay Area	CI (MW)	ENV (MW)	HDG (MW)
DG	145	441	737
NonCREZ	0	2	0
Solano	200	0	0

Overview of Identified Issues in Greater Bay Area

Portfolio	Thermal Overloads		Voltage Concerns	
	Peak	Off-peak	Peak	Off-peak
Commercial Interest (Base)	2	0	1	0
Environmental	2	0	1	0
High DG	1	0	1	0

Greater Bay Area – Summer Peak Results

- **Thermal Overloads**

GBA PG&E, Peak Load 2023, Thermal Overloads							
San Jose Area							
Overloaded Facility	Worst Contingency	Category	Category Description	Loading (%)			Potential Mitigation
				CI	ENV	HDG	
Metcalf-Morgan Hill 115 kV Line	C127b_BUS FAULT AT 35648 LLAGAS F 115.00	C1	Bus	111%	110%	97%	Localized concern. Should be addressed in GIP.
Metcalf-Llagas 115 kV Line	C127b_BUS FAULT AT 35648 LLAGAS F 115.00	C1	Bus	120%	118%	105%	Localized concern. Should be addressed in GIP.

Greater Bay Area – Summer Peak Results

- **Voltage concerns identified**

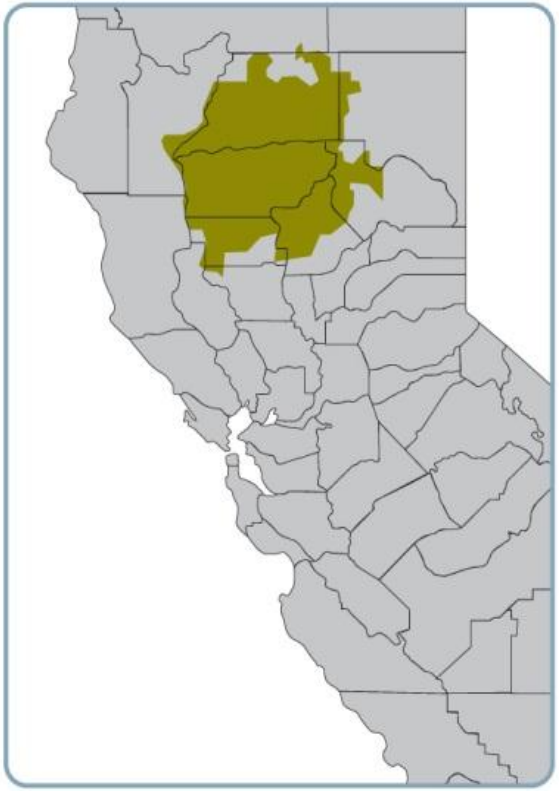
GBA PG&E, Peak Load 2023, Thermal Overloads							
San Jose Area							
Overloaded Facility	Worst Contingency	Category	Category Description	Voltage Deviation (%)			Potential Mitigation
				CI	ENV	HDG	
ALMADEN 60kV	Evergreen-Almaden 60 kV Line	B	L-1	6.9%	7%	6.9%	Localized concern. Should be addressed in GIP.

North Valley / Central Valley Area Results

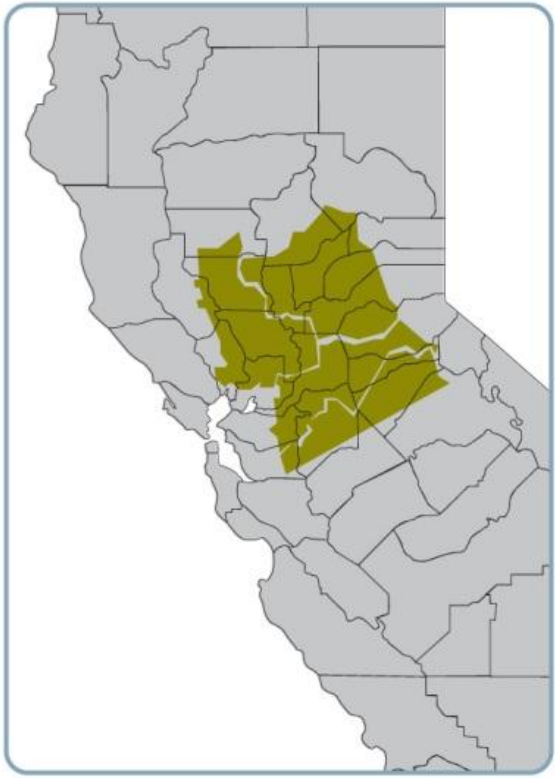
North Valley & Central Valley Area Overview

Renewable generation modeled in North Valley / Central Valley area

North Valley	CI	ENV	HDG
DG	0	0	288
NonCREZ	7	72	7



Central Valley	CI	ENV	HDG
DG	0	22	804
NonCREZ	0	21	0
Central Valley North	25	173	25



California ISO
Shaping a Renewed Future

Overview of Identified Issues in North Valley & Central Valley

Portfolio	Thermal Overloads		Voltage Concerns	
	Peak	Off-peak	Peak	Off-peak
Commercial Interest (Base)	1	0	0	0
Environmental	2	4	0	0
High DG	0	0	0	0

North Valley Area – Summer Peak Results

- **Thermal Overloads**

North PG&E, Peak Load 2023, Thermal Overloads							
North Valley Area							
Overloaded Facility	Worst Contingency	Category	Category Description	Loading (%)			Potential Mitigation
				CI	ENV	HDG	
Trinity-Keswick 60 kV Line	Trinity-Cottonwood 115 kV Line	B	L-1	25%	108%	32%	Localized concern. Should be addressed in GIP.
Keswick-Cascade 60 kV Line	Trinity-Cottonwood 115 kV Line	B	L-1	21%	114%	28%	Localized concern. Should be addressed in GIP.
Trinity-Keswick 60 kV Line	COTTONWOOD BUS PARALLEL BKR STUCK 115KV	C2	Stuck-Brk	38%	169%	56%	Localized concern. Should be addressed in GIP.
Keswick-Cascade 60 kV Line	COTTONWOOD BUS PARALLEL BKR STUCK 115KV	C2	Stuck-Brk	34%	185%	54%	Localized concern. Should be addressed in GIP.
Delevan-Cortina 230 kV Line	Delevan-Vaca Dixon No.2 230 kV Line and Delevan-Vaca Dixon No.3 230 kV Line	C5	DCTL	101%	96%	98%	SPS to curtail Colusa.

- **No additional voltage concerns identified**

North Valley Area – Summer Off-peak Results

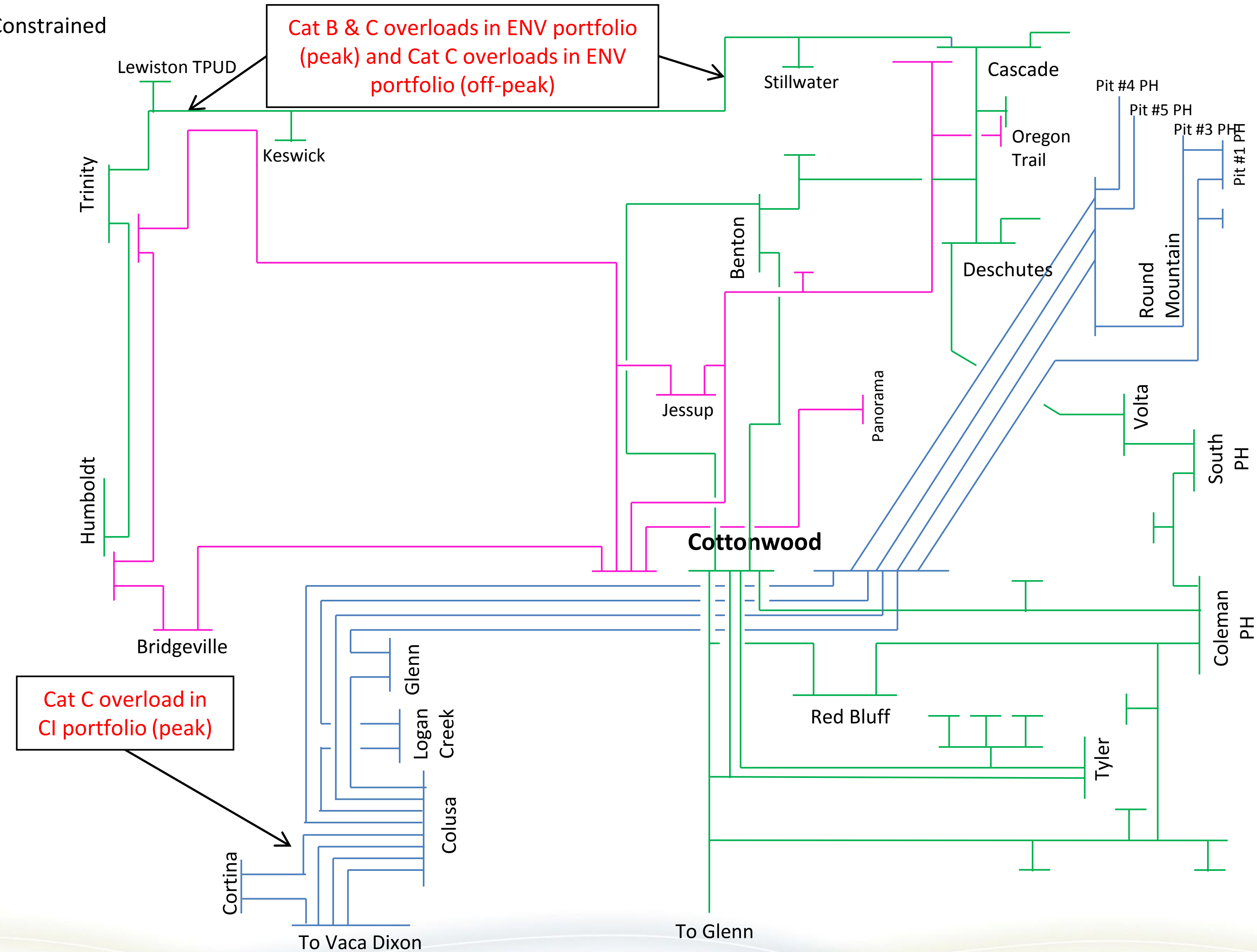
- **Thermal Overloads**

North PG&E, Off-peak Load 2023, Thermal Overloads							
North Valley Area							
Overloaded Facility	Worst Contingency	Category	Category Description	Loading (%)			Potential Mitigation
				CI	ENV	HDG	
Trinity-Keswick 60 kV Line	COTTONWOOD BUS PARALLEL BKR STUCK 115KV	C2	Stuck-Brk	72%	130%	72%	Localized concern. Should be addressed in GIP.
Keswick-Cascade 60 kV Line	COTTONWOOD BUS PARALLEL BKR STUCK 115KV	C2	Stuck-Brk	85%	146%	85%	Localized concern. Should be addressed in GIP.

- **No additional voltage concerns identified**

North Valley Area – Results

CI – Commercial Interest
ENV – Environmentally Constrained
HDG – High DG



Central Valley Area – Summer Peak Results

- **No additional thermal overloads or voltage concerns identified**

Central Valley Area – Summer Off-Peak Results

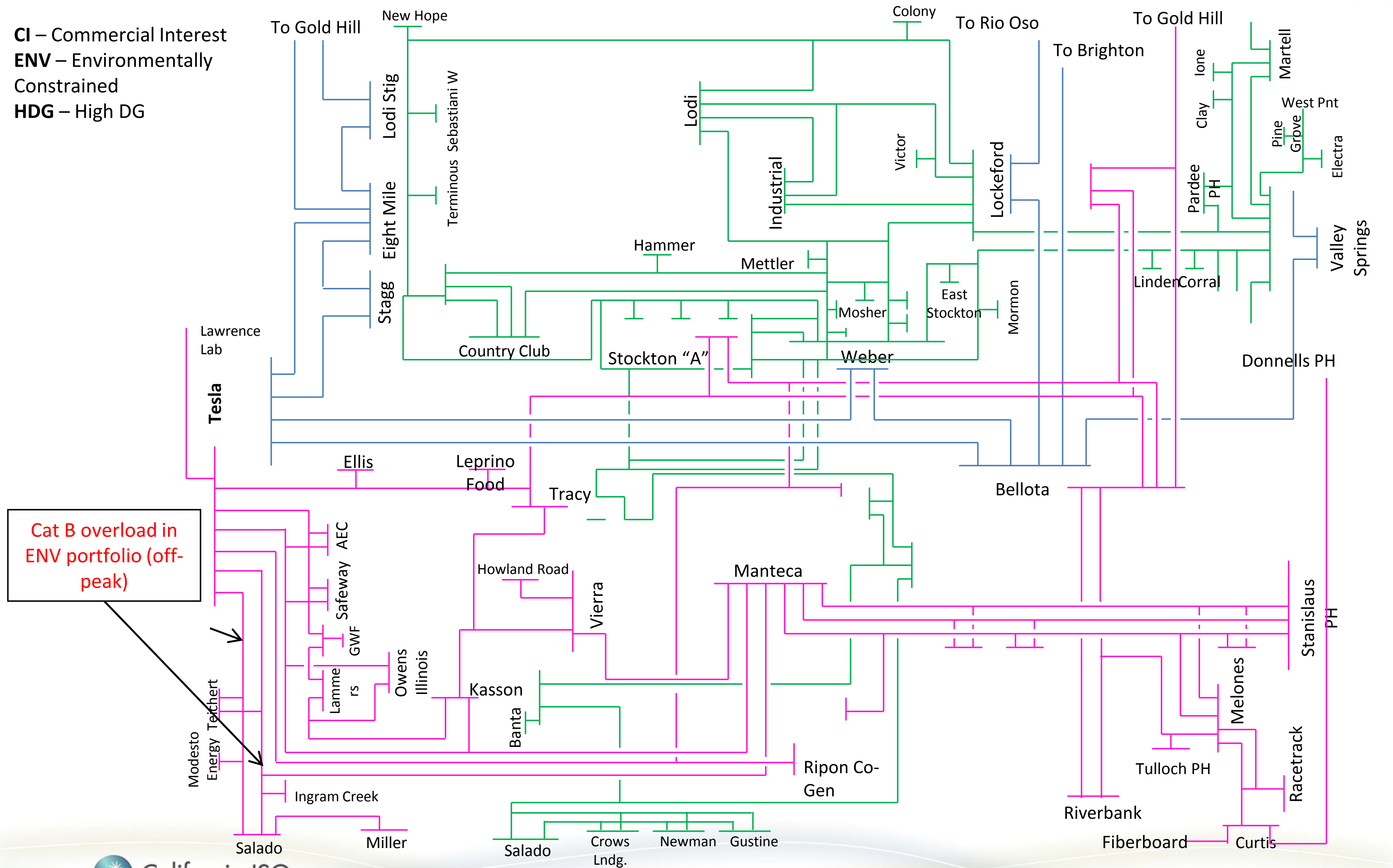
- **Thermal Overloads**

North PG&E, Off-peak Load 2023, Thermal Overloads							
Central Valley Area							
Overloaded Facility	Worst Contingency	Category	Category Description	Loading (%)			Potential Mitigation
				CI	ENV	HDG	
Tesla - Salado - Manteca 115 kV Line	Tesla - Salado 115 kV Line No. 1	B	N-1	20%	165%	20%	Localized concern. Should be addressed in GIP.
Tesla - Salado 115 kV Line No. 1	Tesla - Salado - Manteca 115 kV Line	B	N-1	19%	157%	19%	Localized concern. Should be addressed in GIP.

- **No additional voltage concerns identified**

Central Valley Area (Stockton) – Results

CI – Commercial Interest
ENV – Environmentally Constrained
HDG – High DG



Central Coast / Los Padres Area Results

Central Coast & Los Padres Areas Overview

Renewable generation modeled in Central Coast / Los Padres area

Central Coast & Los Padres	CI (MW)	ENV (MW)	HDG (MW)
DG	152	155	106
Carrizo South	900	900	300

Overview of Identified Issues in Central Coast / Los Padres

Portfolio	Thermal Overloads		Voltage Concerns	
	Peak	Off-peak	Peak	Off-peak
Commercial Interest (Base)	0	0	0	0
Environmental	0	0	0	0
High DG	0	0	0	0

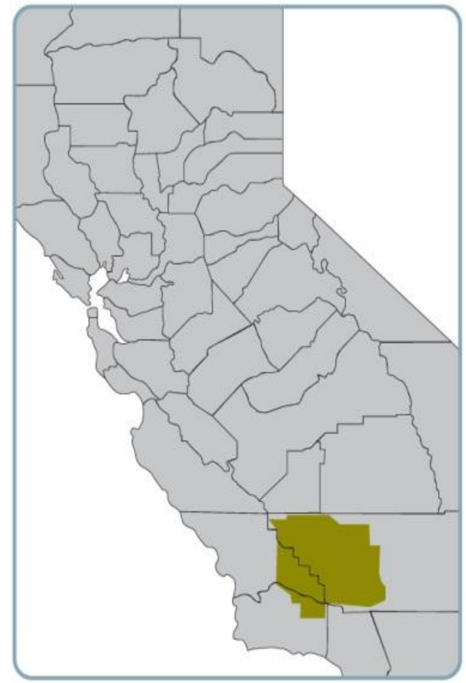
Fresno / Kern Area Results

Fresno & Kern Area Overview

Renewable generation modeled in Central Coast / Los Padres area

Fresno	CI	ENV	HDG
DG	353	421	499
Los Banos	370	0	0
Merced	62	62	62
Westlands	148	1285	148

Kern	CI	ENV	HDG
DG	326	336	372



Overview of Identified Issues for Fresno

Portfolio	Thermal Overloads		Voltage Concerns	
	Peak	Off-peak	Peak	Off-peak
Commercial Interest (Base)	0	0	0	0
Environmental	0	49	0	0
High DG	0	0	0	0

Overview of Identified Issues for Kern

Portfolio	Thermal Overloads		Voltage Concerns	
	Peak	Off-peak	Peak	Off-peak
Commercial Interest (Base)	0	1	0	0
Environmental	0	1	0	0
High DG	0	0	0	0

Fresno Area – Summer Peak Results

- **No thermal overloads**
- **No additional voltage concerns**

Kern Area – Summer Peak Results

- **No thermal overloads**
- **No additional voltage concerns**

Fresno Area – Summer Off-peak Results

- **Thermal Overloads**

Fresno Area, Off-peak Load 2023, Thermal Overloads							
Overloaded Facility	Worst Contingency	Category	Category Description	Loading (%)			Potential Mitigation
				CI	ENV	HDG	
2C577-Los Banos 230kV	Base Case	A	None	<90%	106%	<90%	Congestion Management
Corcoran #1 115/70kV	Base Case	A	None	<90%	146%	<90%	Local issue to be addressed by GIP
Corcoran-Angiola 70kV (Boswell Tap-Boswell Tomato Plant Section)	Base Case	A	None	<90%	317%	<90%	Local issue to be addressed by GIP
Kingsburg-Corcoran #1 115kV	Base Case	A	None	<90%	137%	<90%	Local issue to be addressed by GIP
Kingsburg-Waukena Sw Sta 115kV	Base Case	A	None	<90%	144%	<90%	Local issue to be addressed by GIP
Panoche-Schindler #1 115kV (Kamm-Cantua Section)	Base Case	A	None	<90%	109%	<90%	Local issue to be addressed by GIP
Panoche-Schindler #2 115kV (Panoche-Cheney Tap Section)	Base Case	A	None	<90%	107%	<90%	Local issue to be addressed by GIP
Schindler-Huron-Gates 70kV (Schindler-S532SS Section)	Base Case	A	None	<90%	122%	<90%	Local issue to be addressed by GIP

- **CatB and CatC in Panoche-Schindler-Coalinga and Corcoran areas (Overgen in OffPk)**
- **No additional voltage concerns identified**

Kern Area – Summer Off-peak Results

- **Thermal Overloads**

Kern Area, Off-peak Load 2023, Thermal Overloads							
Overloaded Facility	Worst Contingency	Category	Category Description	Loading (%)			Potential Mitigation
				CI	ENV	HDG	
Fellows-Taft 115kV (Fellows-Morgan Section)	Midway-Taft 115kV	B	L-1	114%	115%	<90%	Local issues to be addressed by GIP

- **No additional voltage concerns identified**

Policy Driven Planning Deliverability Assessment Results – PG&E Area

2013/2014 Transmission Planning Process Stakeholder Meeting

Abhishek Singh
Sr. Regional Transmission Engineer
November 20-21, 2013

Overview of renewable zones that impact PG&E area

Renewable Zone	Base Portfolio MW
Carrizo South	900
Central Valley North	25
Los Banos	370
Merced	62
Solano	200
Westlands	148
NonCREZ	73
Distributed Generation – PG&E	984
Total	2,762

Deliverability Assessment Results for PG&E North Area – Cayetano-Lone Tree 230 kV line

Overloaded Facility	Contingency	Flow
Cayetano-Lone Tree(USWP-JRW-Lone Tree) 230kV Line	Contra Costa-Moraga Nos. 1 & 2 230 kV lines	100.3%
Cayetano-Lone Tree(Cayetano-USWP-JRW) 230kV Line	Contra Costa-Moraga Nos. 1 & 2 230 kV lines	104.4%

Cayetano-Lone Tree Line Deliverability Constraint	
Constrained Renewable Zones	Contra Costa
Total Renewable MW Affected	27
Deliverable MW w/o Mitigation	0
Mitigation	Under evaluation

Deliverability Assessment Results for PG&E North 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	107%

Delevan-Cortina Line Deliverability Constraint	
Constrained Renewable Zones	Cottonwood Area (115 kV)
Total Renewable MW Affected	5.5 MW
Deliverable MW w/o Mitigation	0 MW
Mitigation	Under evaluation

Deliverability Assessment Results for PG&E South Area – Chowchilla-Kerckhoff 115 kV line

Overloaded Facility	Contingency	Flow
Chowchilla-Kerckhoff - From Chowchilla Sub To 2/16C (Chowchilla-CertanJ1)	Kerckhoff-E2 #1 & #2 115 kV Lines	156%
Chowchilla-Kerckhoff - From 2/16C To 34/9 (CertanJ1-Sharon Tap)	Kerckhoff-E2 #1 & #2 115 kV Lines	156%
Chowchilla-Kerckhoff - From 34/9 To 7/11 (Sharon Tap-Oakhurst Junction))	Kerckhoff-E2 #1 & #2 115 kV Lines	161%

Chowchilla-Kerckhoff Deliverability Constraint	
Constrained Renewable Zones	PG&E DG
Total Renewable MW Affected	6.7 MW
Deliverable MW w/o Mitigation	0 MW
Mitigation	Under evaluation (Also seen in Reliability Analysis)

Deliverability Assessment Results for PG&E South Area – Kerckhoff Clovis Sanger 115 kV line # 1

Overloaded Facility	Contingency	Flow
Shepherd to Woodward 115 kV Line.	Gregg-E1 (New) #1 & #2 230 kV Line	118%
Shepherd to E2 (New Sub) 115 kV Line.	Gregg-E1 (New) #1 & #2 230 kV Line	120%

Kerckhoff Clovis Sanger 115 kV Line # 1 Deliverability Constraint	
Constrained Renewable Zones	PG&E DG & Westlands (Corcoran 115 kV)
Total Renewable MW Affected	167 MW
Deliverable MW w/o Mitigation	0 MW
Mitigation	Under evaluation (Also seen in Reliability Analysis)

California ISO
Shaping a Renewed Future

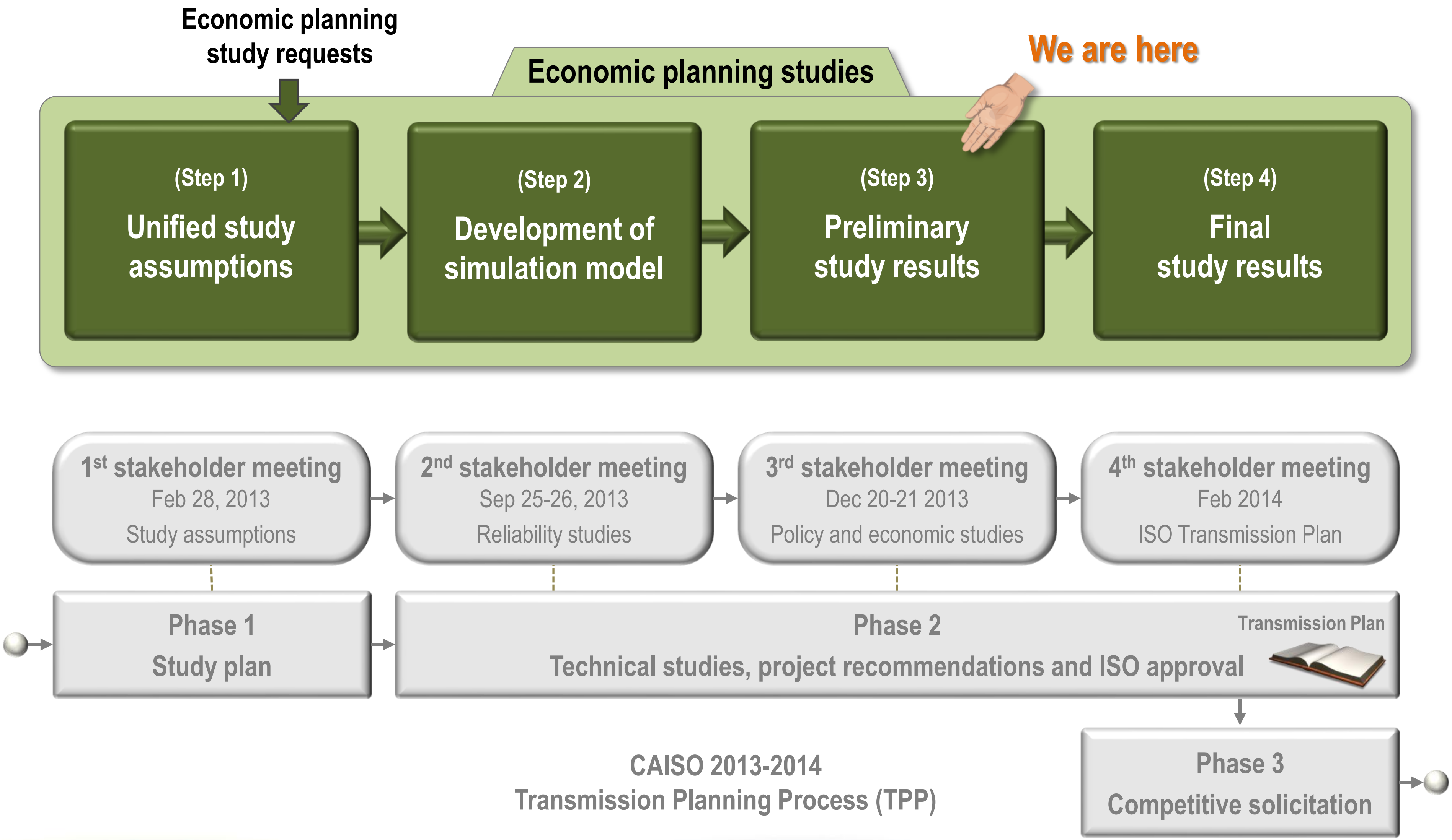
Economic Planning Studies

Part 1: Introduction

Xiaobo Wang, PhD
Regional Transmission Engineering Lead

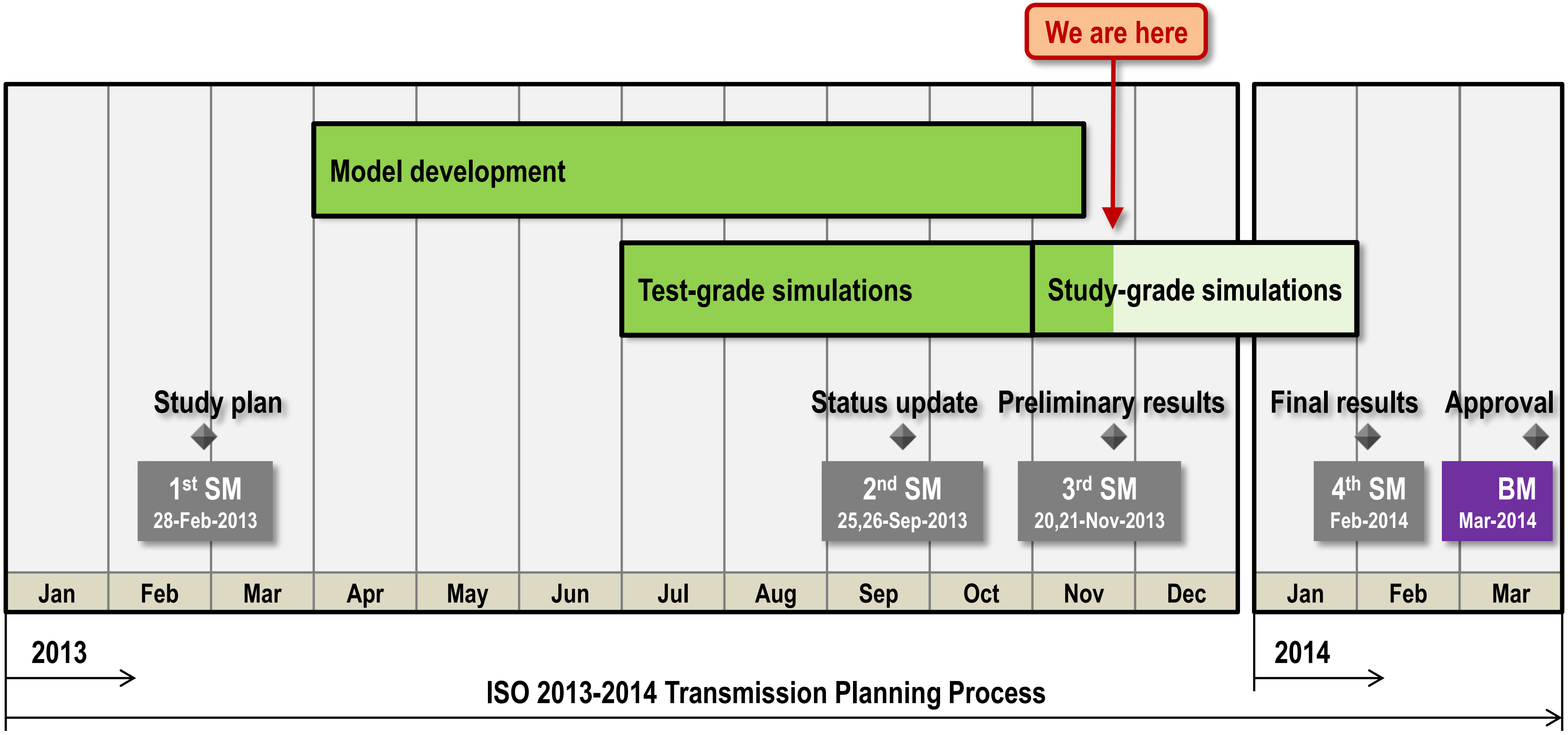
ISO Transmission Planning Stakeholder Meeting
Folsom CA
November 20-21, 2013

Steps of economic planning studies



Timeline of the economic planning studies

Model development and simulation studies



Acronyms:
SM = Stakeholder Meeting
BM = Board of Governors Meeting

California ISO
Shaping a Renewed Future

Preliminary results of the economic planning studies

ISO 2013-2014 Transmission Planning Process

Five high-priority studies and preliminary results:

ID	Transmission Facilities	Operation year	Cost	Benefit	Production benefit	Capacity benefit	BCR
P26-3	Build Midway – Vincent 500 kV line #4	2018	$1,595M	$55M	$55M	-	0.03
NWC-1	Increase PDCI capacity by 500 MW	2018	$435M	-$4M	$51M	-$55M	-0.01
SWC-1	Harry Allen – Eldorado 500 kV line	2023	$174M	$138M	$138M	TBD	0.79
SWC-2	Delaney – Colorado River 500 kV line	2020	$498M	$645M	$364M	$281M	1.30
SWC-3	North Gila – Imperial Valley 500 kV line #2	2018	$428M	$279M	$279M	-	0.65

The dollar values are in 2012$ values discounted to the assumed operational year

Note:
In the above table, the red texts are values to be determined or updated
Work is in progress to compute the capacity benefits of the studied subjects

These are *preliminary* study results

The set of presentations are organized as follows

Thanks!

Your questions and comments are welcome

For clarifying questions, please contact Xiaobo Wang at:
(916)608-1264, XBWang@caiso.com

For written comments, please send to:
RegionalTransmission@caiso.com

Economic Planning Studies

Part 2: Methodology and Database

Xiaobo Wang, PhD

Regional Transmission Engineering Lead

ISO Transmission Planning Stakeholder Meeting

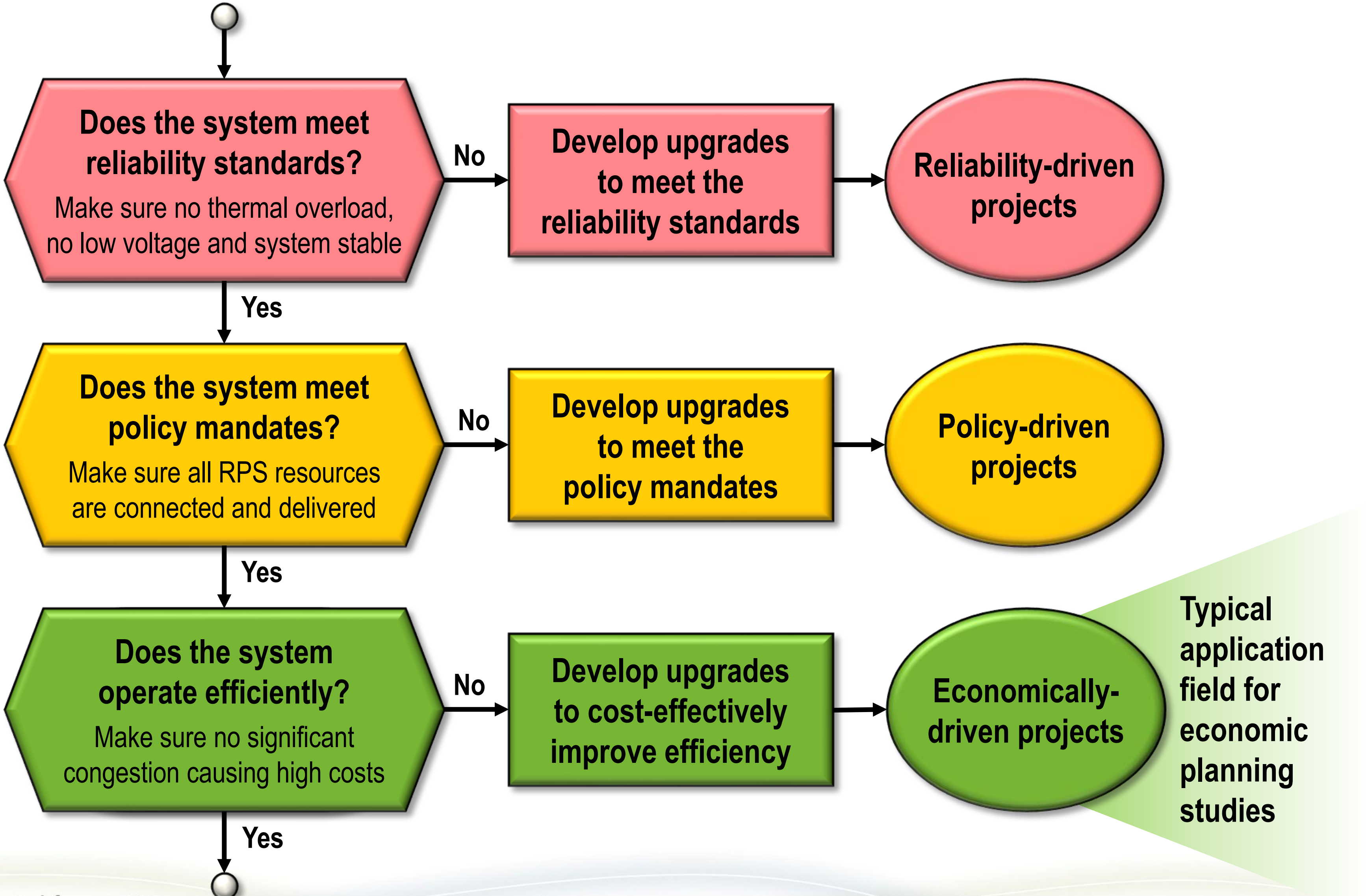
Folsom CA

November 20-21, 2013

Table of Contents

Reliability-, policy- and economically-driven upgrades

Where does economic planning study fit?

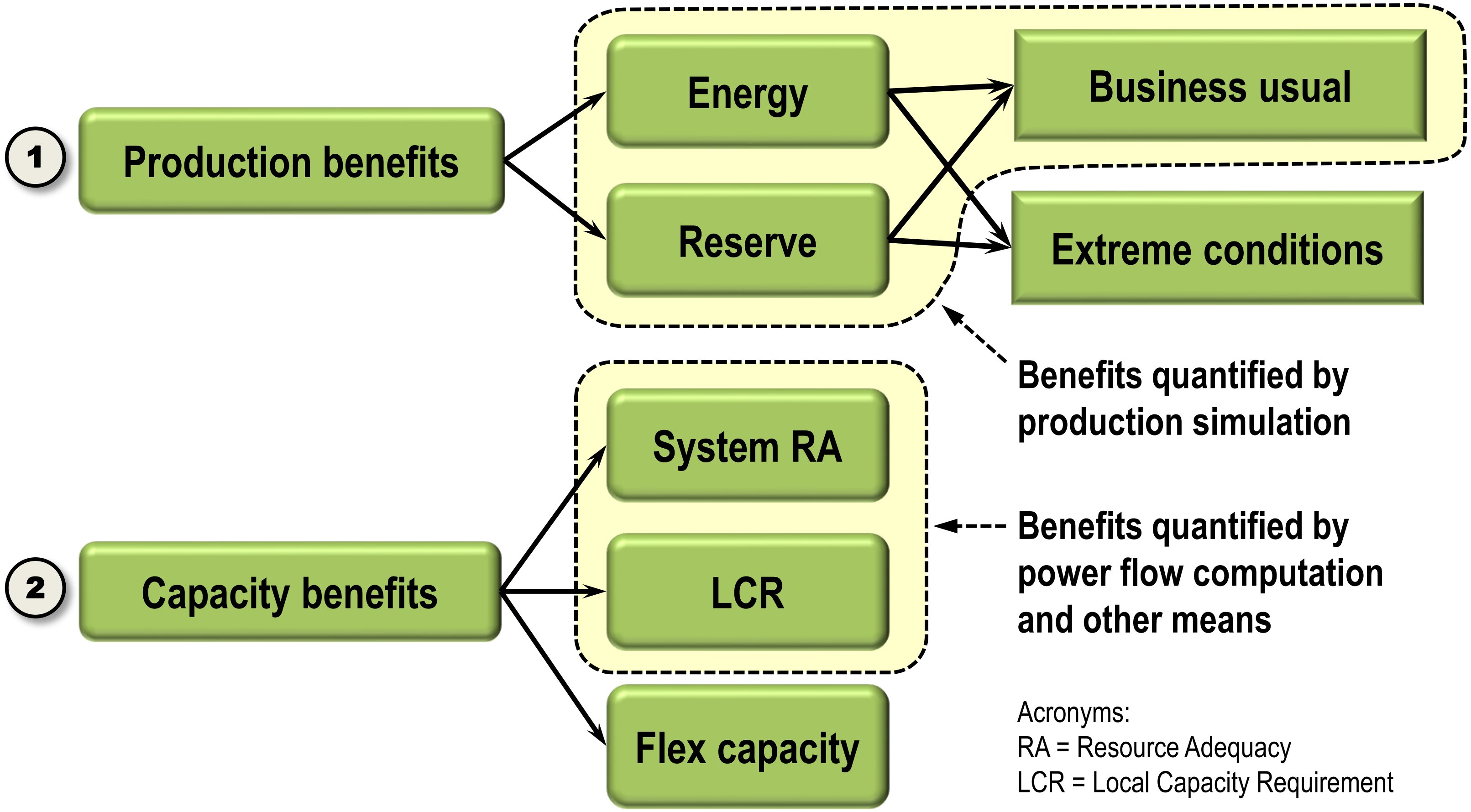


What is economic planning study?

Keywords

- Economic planning study
- Congestion study
- Significant and recurring congestion
- Economic planning study requests
- High-priority studies
- Production simulation for 8,760 hours
- Security-constrained unit commitment and economic dispatch
- Production benefits
- Capacity benefits
- Any other benefits
- Transmission Economic Assessment Methodology (TEAM)
- Benefits to the ISO ratepayers
- Capital cost
- Revenue requirement
- Cost-benefit analysis (CBA)
- Benefit-cost ratio (BCR)
- Net benefit
- Economically-driven upgrades

Components of economic benefits



3 **Other benefits**

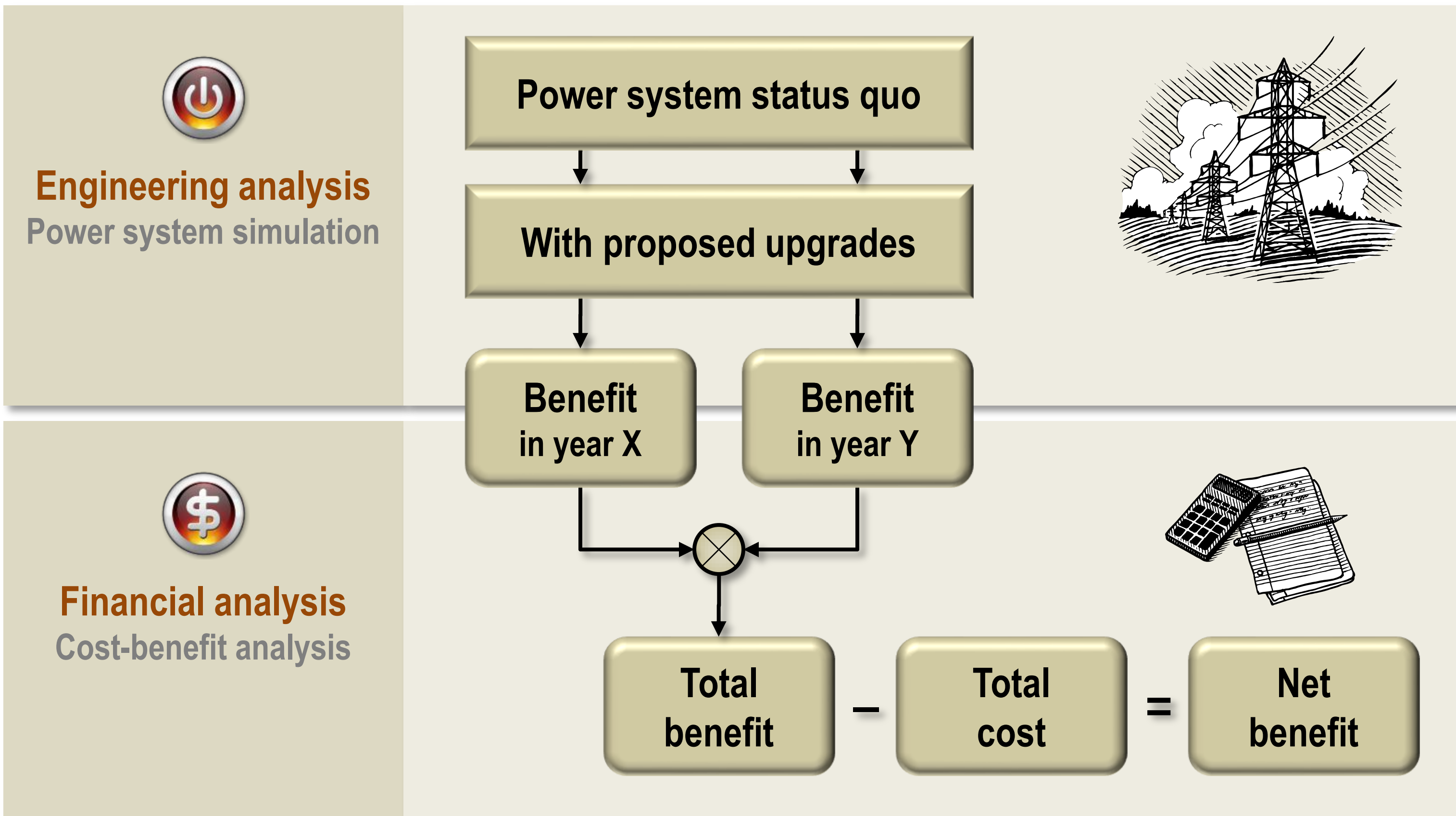
e.g. social and political

Can all benefits be quantified?

Are we on liberal or conservative side?

Economic planning studies

Engineering and accounting analyses

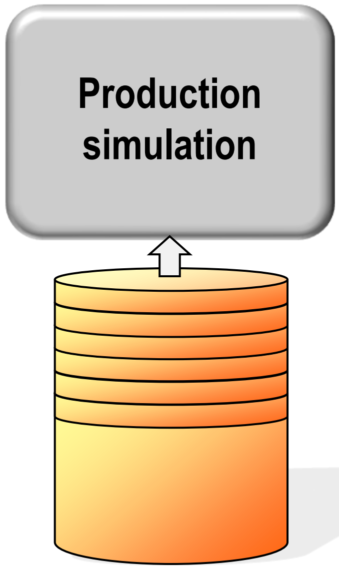


In order for a proposed network upgrade to qualify as an economic project, the study has to demonstrate a positive net benefit for the ISO ratepayers

Given multiple alternatives, the most economic solution is the alternative that has the largest net benefit

Table of Contents

Database and simulation tools



Extensive analysis throughout 8760 hours

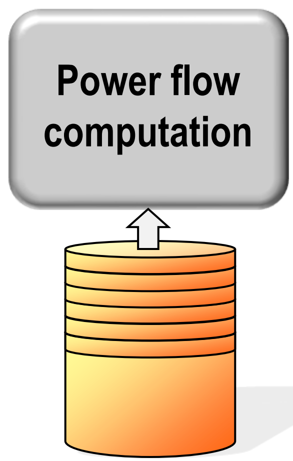
Identifies congestion based on security-constrained unit commitment (SCUC) and security-constrained economic dispatch (SCED)

Database size: 4,000 MB

ABB GridView™
Version 8.3 dated 8-Jun-2013

CAISO modeling additions
Numerous updates and improvements

WECC TEPPC product simulation database
Dataset “2022 PC1” released on 2-May-2012



Intensive analysis for selected hours

Identifies thermal overload and voltage deviation based on stressed system conditions, e.g. peak load under certain generation dispatch patterns

Database size: 12 MB

GE PSLF™
Version 18.0_01 dated 24-Oct-2011

CAISO modeling additions

WECC PCC power flow base cases

TEPPC = Transmission Expansion Planning Policy Committee
PCC = Planning Coordination Committee

CAISO modeling additions to the TEPPC database

Part 1 of 3: System modeling

#	ISO modeling additions and changes	TEPPC database
1	Representation of 31 BAAs, i.e. control areas	Representation of six geographic regions
2	Wheeling tariffs between the BAAs	Hurdle rates between the six regions
3	Trading hub models	Not available
4	VEA system joins the ISO	Not available
5	Merced Irrigation District joins the ISO	Not available
6	PacifiCorp-ISO EIM	Not available
7	Dynamic resources in the ISO market	Not available
8	ISO-calculated flexible reserve requirements	NREL-calculated flexible reserve requirements
9	California GHG emission model based on AB32	No emission model
10	CEC NAMGas natural gas model	NPCC natural gas model

Acronyms:
BAA = Balancing authority area
CEC = California Energy Commission
GHG = Green house gas
NREL = National Renewable Energy Laboratory
NPCC = Northwest Power Conservation Council

CAISO modeling additions to the TEPPC database

Part 2 of 3: Load and resources

#	ISO modeling additions and changes	TEPPC database
1	2012 load forecast based on LRS data	2011 load forecast based on LRS data
2	2012 CEC load with AAEE	Not available
3	Four seasonal load distribution patterns	Summer load distribution pattern only
4	SONGS retirement	SONGS in operation
5	Updated California OTC assumptions	Default California OTC assumptions
6	2013 CPUC/CEC 33% RPS net short portfolios	2011 CPUC/CEC 33% RPS net short portfolios
7	Recent announcement of coal retirements	Status quo conditions of coal generation

Acronyms:
AAEE = Additional achievable energy efficiency
CEC = California Energy Commission
CPUC = California Public Utility Commission
LRS = Load and Resources Subcommittee
OTC = Once-through-cooling
RPS = Renewable Portfolio Standard
SONGS = San Onofre Nuclear Generating Station

CAISO modeling additions to the TEPPC database

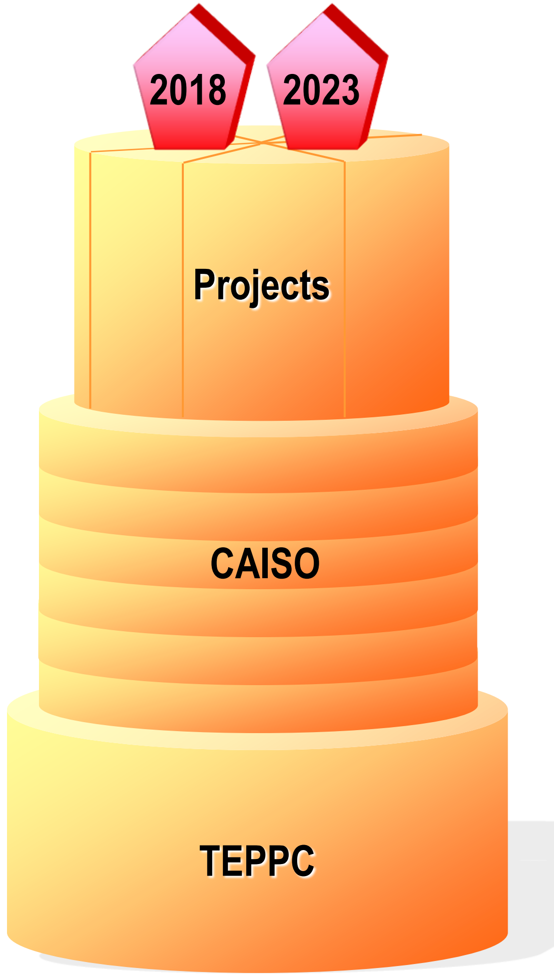
Part 3 of 3: Transmission

#	ISO modeling additions and changes	TEPPC database
1	Network upgrades approved in recent ISO Transmission Plans (230 kV and above)	Not available
2	Enforcement of all 500 kV transformer limits and 345 kV branch limits in WECC	Not enforced
3	Enforcement of all 230 kV branch limits and some 115 kV line limits in California	Summer load distribution pattern only
4	Winter ratings of California transmission lines in addition to summer ratings	Summer ratings only
5	Dynamic transmission limits on Path 15 and Path 26 based on operating procedures	The paths have fixed limits
6	What-if contingencies in the CA 500 kV and 230 kV transmission system	Not available
7	Forced outages on some backbone CA 500 kV lines	Not available

Table of Contents

Database architecture (Page 1 of 2)

Hierarchy



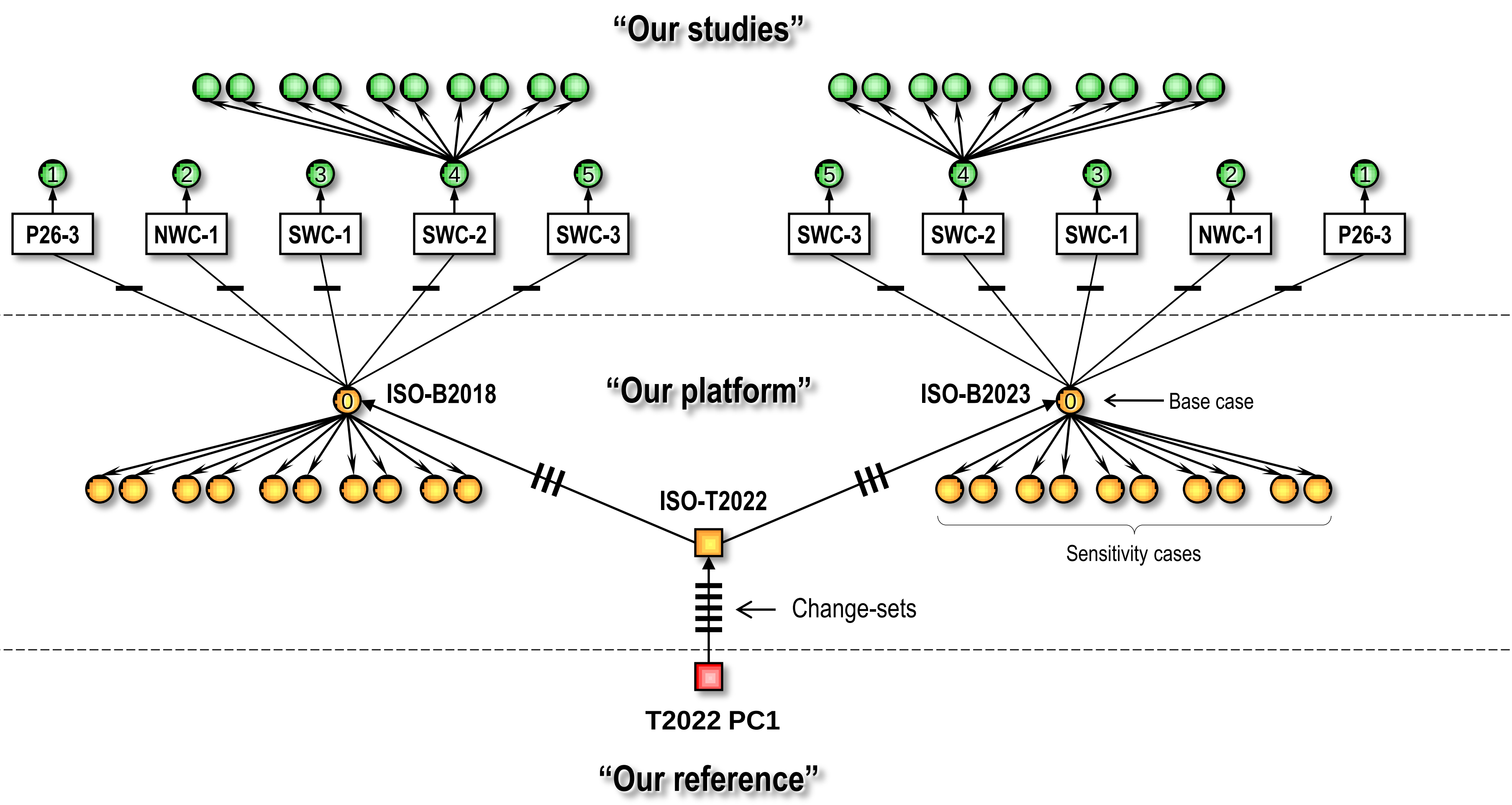
Project modeling - "Our studies"
- New lines
- New stations
- New ratings
- New non-wire solutions

CAISO database - "Our platform"
- 2018 and 2023 load
- 2018 and 2023 fuel prices
- 2018 and 2023 RPS portfolios
- New generation projects
- New transmission projects
- More detailed modeling of the system

TEPPC database - "Our reference"
- 2022 WECC dataset

Database architecture (Page 2 of 2)

Tree structure



In this diagram, a total of 52 cases are shown
Each case takes 15 hours to run 8,760 hourly production simulation
If all cases are calculated in serial, it would take 33 days to run the simulations!

ISO production simulation model

Database development and releases

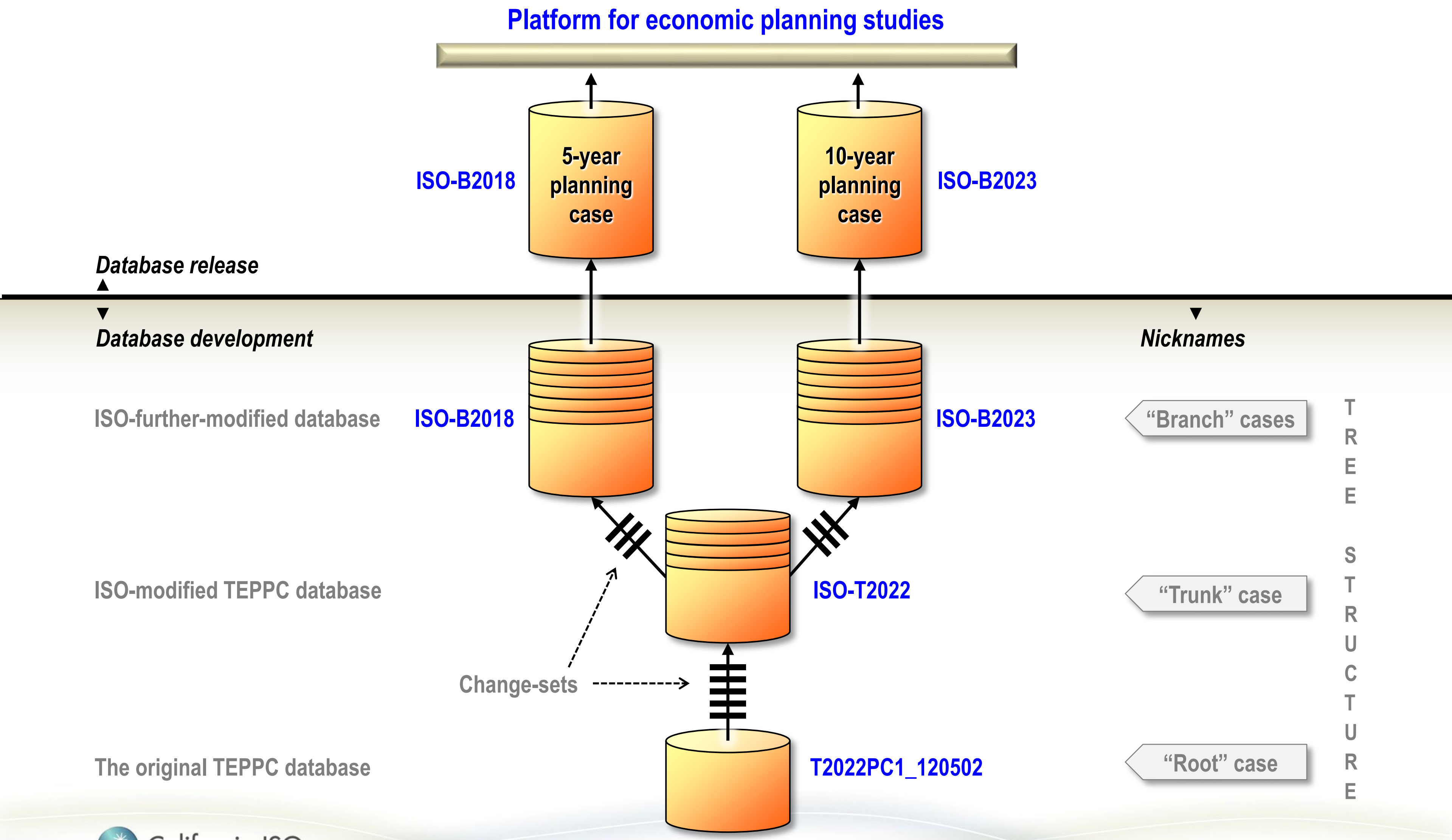
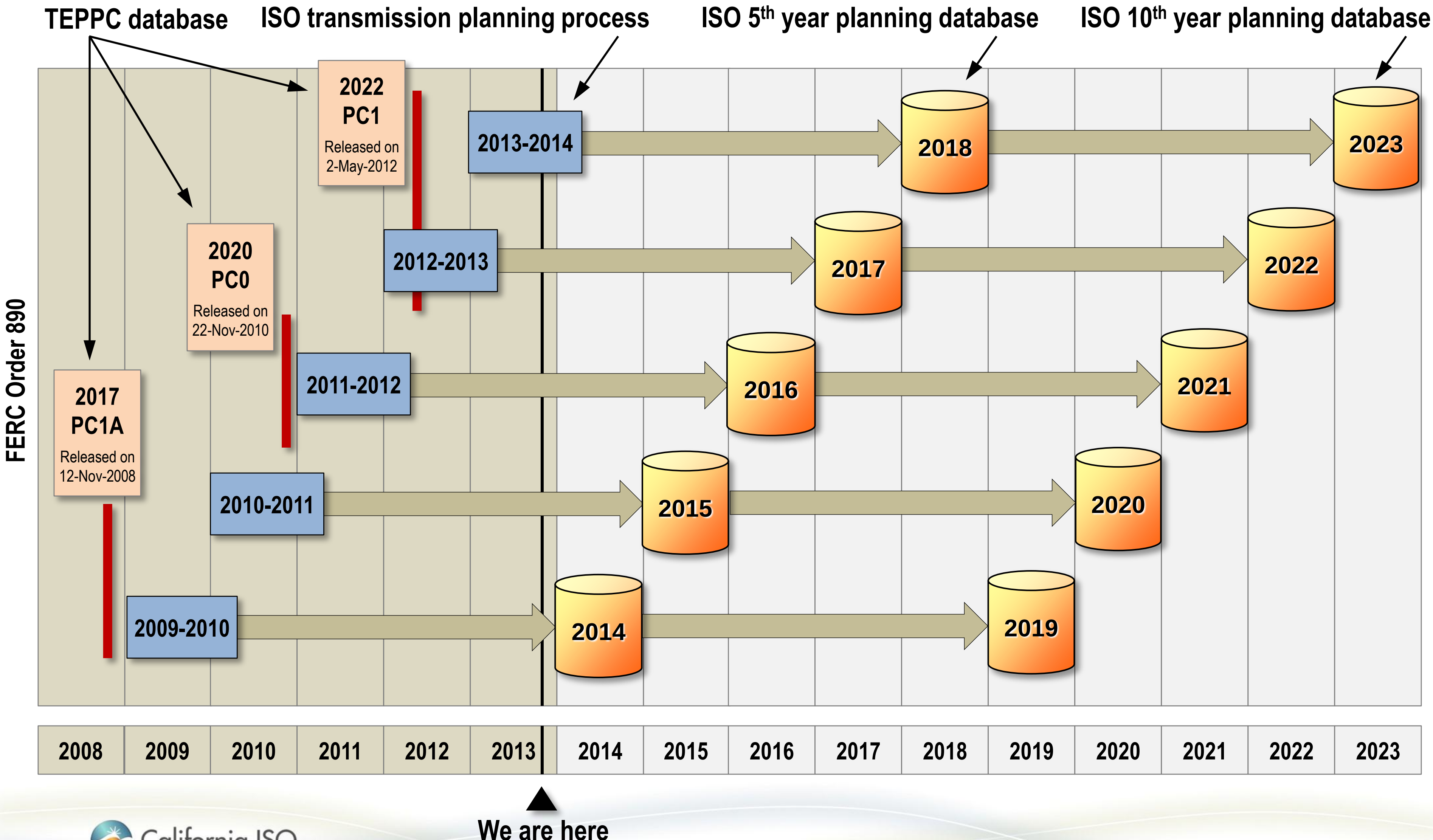


Table of Contents

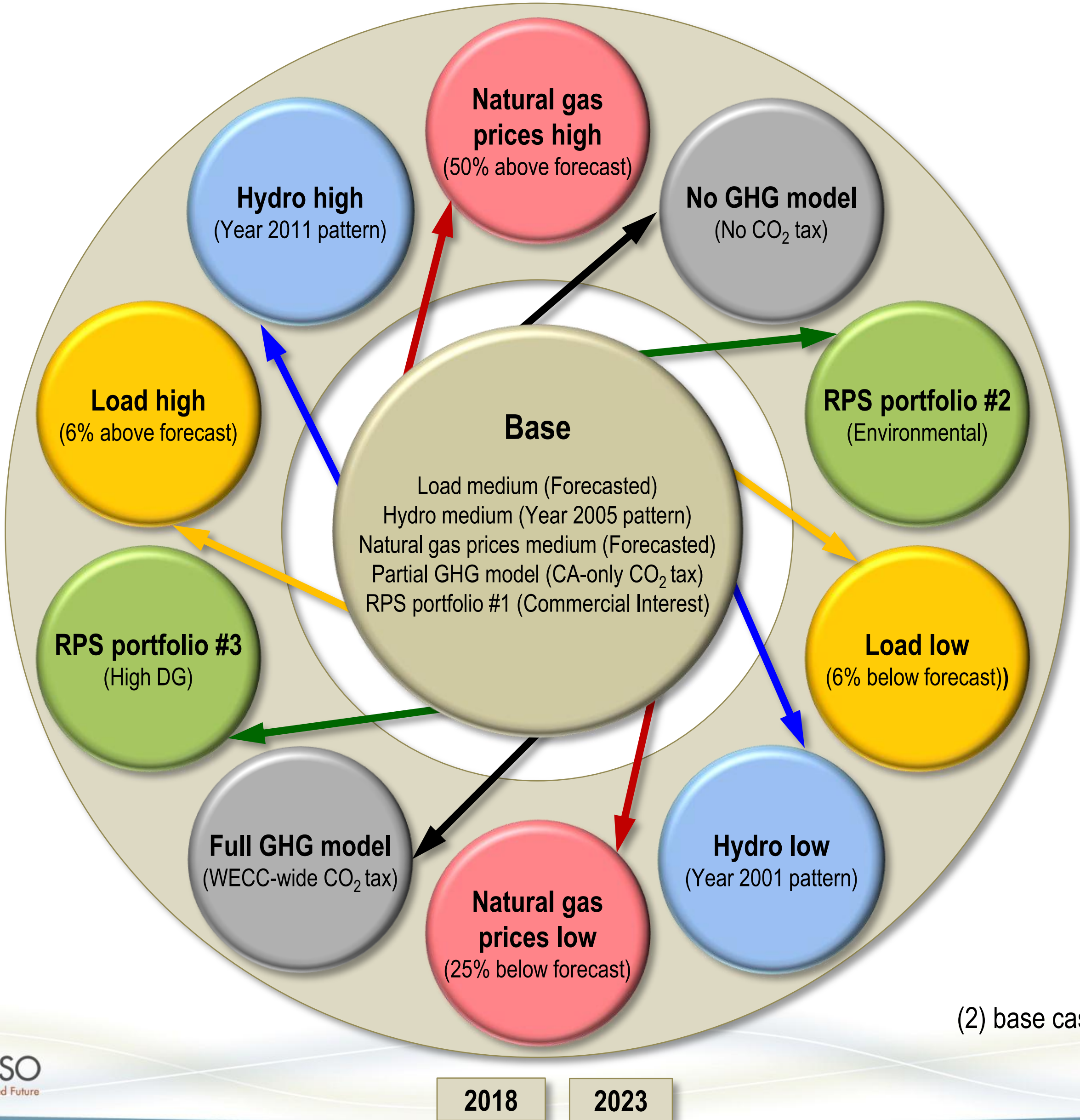
ISO production simulation model

Database developed in recent years



ISO production simulation model

Base cases and sensitivity cases



Count:
(2) base cases and (20) sensitivity cases

ISO production simulation model

Base cases and sensitivity cases

ISO database "DB131112"

		Descriptions	Year 2018 case	Year 2023 case
Base	Load Hydro Natural gas prices GHG model CA RPS portfolio	Medium load (Forecasted) Medium hydro (Year 2005 pattern) Medium natural gas prices (Forecasted) Partial (CA-only CO_2 tax) RPS portfolio #1 (Commercial Interest)	ISO-B2018_131112	ISO-B2023_131112
Sensitivity	Load	High (+6% above the forecast)	ISO-B2018_131112_L+6%	ISO-B2023_131112_L+6%
		Low (+6% above the forecast)	ISO-B2018_131112_L-6%	ISO-B2023_131112_L-6%
	Hydro	Wet (Year 2011 pattern)	ISO-B2018_131112_H_Wet	ISO-B2023_131112_H_Wet
		Dry (Year 2001 pattern)	ISO-B2018_131112_H_Dry	ISO-B2023_131112_H_Dry
	Natural gas prices	High (+50% above the forecast)	ISO-B2018_131112_NG+50%	ISO-B2023_131112_NG+50%
		Low (-25% below the forecast)	ISO-B2018_131112_NG-25%	ISO-B2023_131112_NG-25%
	GHG model	None (No CO_2 tax)	ISO-B2018_131112_GHG_N	ISO-B2023_131112_GHG_N
		Full (WECC-wide CO_2 tax)	ISO-B2018_131112_GHG_W	ISO-B2023_131112_GHG_W
	CA RPS portfolio	RPS portfolio #2 (Environmental)	ISO-B2018_131112_RPS_EC	ISO-B2023_131112_RPS_EC
		RPS portfolio #3 (High DG)	ISO-B2018_131112_RPS_HD	ISO-B2023_131112_RPS_HD

Count: (2) base cases and (20) sensitivity cases
In ABB GridView format
Published on the ISO Market Participant Portal

Thanks!

Your questions and comments are welcome

For clarifying questions, please contact Xiaobo Wang at:
(916)608-1264, XBWang@caiso.com

For written comments, please send to:
RegionalTransmission@caiso.com

California ISO
Shaping a Renewed Future

Economic Planning Studies

Part 3: Study Assumptions

Xiaobo Wang, PhD

Regional Transmission Engineering Lead

ISO Transmission Planning Stakeholder Meeting

Folsom CA

November 20-21, 2013

Table of Contents

Assumptions for engineering analysis

Category	Type	TP2013-2014	TP2012-2013
Load	In-state load	CEC 2011 IEPR (2018, 2023) with AAEE	CEC 2011 IEPR (2017, 2022) w/o AAEE
	Out-of-state load	LRS 2012 data (2018, 2023)	LRS 2012 data (2017, 2022)
	Load profiles	TEPPC profiles plus CPUC profiles for DG	TEPPC profiles
	Load distribution	Four seasonal load distribution patterns	Same
Generation	RPS	CPUC/CEC 2013 RPS portfolios	CPUC/CEC 2012 RPS portfolios
	Hydro and pumps	TEPPC hydro data based on year 2005 pattern	Same
	Coal	Coal retirements in Southwest	Status quo
	Nuclear	SONGS retirement	SONGS available
	Once-Thru-Cooling	Based on ISO TP2012 nuke sensitivity study results	ISO 2012 OTC assumptions
	Natural gas units	ISO 2012 Unified Study Assumptions	Almost the same
	Natural gas prices	CEC 2013 IEPR Preliminary – NAMGas (2018, 2023)	E3 2010 MPR prices (2017, 2022)
	Other fuel prices	TEPPC fuel prices	Same
	GHG prices	CEC 2013 IEPR Preliminary – CO_2 prices	CPUC 2011 MPR – CO_2 prices
Transmission	Reliability upgrades	Plus to-be-approved projects in this planning cycle	Already-approved projects
	Policy upgrades	Plus to-be-approved projects in this planning cycle	Already-approved projects
	Economic upgrades	No economically-driven upgrades	Same

▲ ▲ ▲ ▲ ▲

- Major differences
- Minor differences

Acronyms:
AAEE = Additional achievable energy efficiency
DG = Distributed generation

Assumptions for financial analysis

Calculation of cost, i.e. revenue requirement

Item	TP2013-2014	TP2012-2013
Return on equity (real)	11%	N/A
Discount rate (real)	7%	N/A
California state tax	8.84%	N/A
O&M	2%	N/A
Property tax	2%	N/A
Inflation rate	2%	N/A
Asset depreciation horizon	50 years	N/A

Other assumptions:
Deferred tax revenue recovery
CWIP in rate base treatment

▲ ▲ ▲ ▲ ▲

- Major changes
- Minor changes

Note:
When detailed capital cash flows are not available, revenue requirement is approximately estimated from the capital cost.
The estimation is made by RR = 1.45 * CC, where the multiplier is based on estimating ISO prior experience on California IOUs.
This estimation approach is used only when project-specific analysis is not available at initial planning stage.
Actual revenue requirements are calculated based on project-specific information conducted on a case-by-case basis

Acronyms:
O&M = Operations and maintenance
CWIP = Construction work in progress
CC = Capital cost
RR = Revenue requirement
IOU = Investor-owned utilities

Assumptions for financial analysis (cont'd)

Calculation of benefits

Item	TP2013-2014	TP2012-2013
Discount rate (real)	7%	Same
Escalation rate (real) for extrapolation of yearly benefits	0%	1%
Economic lifespan for new build of transmission facilities	50 years	Same
Economic lifespan for upgrades of existing transmission facilities	40 years	Same
Value of increased system RA import	Case-by-case	$5/kW-year
Value of LCR reduction	Case-by-case	$20/kW-year

▲ ▲ ▲ ▲ ▲

- Major changes
- Minor changes

Acronyms:
RA = Resource adequacy
LCR = Local capacity requirement
CC = Capital cost
RR = Revenue requirement
IOU = Investor-owned utilities

Table of Contents

Special study assumptions

As placeholders, the following fictitious transmission upgrades are modeled:

#	Fictitious transmission upgrade	Issue
1	Coolwater – Lugo 230 kV transmission	Needed to connect RPS CA solar in the Coolwater – Pisgah area
2	Inyo 115 kV phase shifter upgrade	Needed to mitigate curtailment of RPS CA geothermal in Inyo area

Such a modeling is needed to establish a feasible and compliant system.

The system has to first meet reliability standards and policy mandates. Only after that, economic planning studies are performed

Table of Contents

Open issues

#	Category	Issue
1	Generation and transmission	LA Basin/San Diego local requirements
2	Transmission	Reliability-driven upgrades identified in this 2013/2014 cycle
3	Transmission	Policy-driven upgrades identified in this 2013/2014 cycle

At this point, it does not appear that
the above issues will negatively impact
the calculated benefits of the studied subjects

Thus, there is no plan to update
the production simulation model

Thanks!

Your questions and comments are welcome

For clarifying questions, please contact Xiaobo Wang at:
(916) 608-1264, XBWang@caiso.com

For written comments, please send to:
RegionalTransmission@caiso.com

Appendix. Data listings

South CA OTC retirement and replacement assumptions

SCE area

Name	Type	Long Name	Commission Date	Retirement Date	MaxCap(MW)
AESAlamts1	Steam Large Old	AES Alamitos 1 Long Beach CA	1956-09-01	2020-12-31	175
AESAlamts2	Steam Large Old	AES Alamitos 2 Long Beach CA	1957-02-01	2020-12-31	175
AESAlamts3	Steam Large Recent	AES Alamitos 3 Long Beach CA	1961-12-01	2020-12-31	332
AESAlamts4	Steam Large Recent	AES Alamitos 4 Long Beach CA	1962-06-01	2020-12-31	336
AESAlamts5	Steam Large Recent	AES Alamitos 5 Long Beach CA	1966-03-01	2020-12-31	498
AESAlamts6	Steam Large Recent	AES Alamitos 6 Long Beach CA	1966-09-01	2020-12-31	495
AESAlamts7	CT Old Gas	AES Alamitos 7 Long Beach CA	1969-07-01	2003-12-31	138
AESHuntBch1	Steam Large Old	AES Huntington Beach 1	1958-06-01	2020-12-31	226
AESHuntBch2	Steam Large Old	AES Huntington Beach 2	1958-12-01	2020-12-31	226
Mandaly1	Steam Large Old	Mandalay 1 Oxnard CA	1959-05-01	2020-12-31	215
Mandaly2	Steam Large Old	Mandalay 2 Oxnard CA	1959-08-01	2020-12-31	215
Mandaly3	CT Old Gas	Mandalay 3 Oxnard CA	1970-04-01	-	130
OrmndBc1	Steam Large Recent	Ormond Beach Gen 1 Oxnard CA	1971-12-01	2020-12-31	741.27
OrmndBc2	Steam Large Recent	Ormond Beach Gen 2 Oxnard CA	1973-06-01	2020-12-31	775
Redondo1	Steam Large Old	AES Redondo Beach 1 R Beach CA	1948-03-01	2020-12-31	175
Redondo2	Steam Large Old	AES Redondo Beach 2 R Beach CA	1948-04-01	2020-12-31	495.9
Redondo5	Steam Large Old	AES Redondo Beach 5 R Beach CA	1954-10-01	2020-12-31	178.87
Redondo7	Steam Large Recent	AES Redondo Beach 7 R Beach CA	1967-02-01	2020-12-31	505.96
SanOnfr2	Nuclear	San Onofre 2 San Clemente CA	1983-08-08	2012-01-09	1122
SanOnfr3	Nuclear	San Onofre 3 San Clemente CA	1984-04-01	2012-01-31	1124
Walnut Crk_1	CT Future	Walnut Creek Energy Center 1	2013-04-30	-	100
Walnut Crk_2	CT Future	Walnut Creek Energy Center 2	2013-04-30	-	100
Walnut Crk_3	CT Future	Walnut Creek Energy Center 3	2013-04-30	-	100
Walnut Crk_4	CT Future	Walnut Creek Energy Center 4	2013-04-30	-	100
Walnut Crk_5	CT Future	El Segundo CC	2013-04-30	-	100
El Segundo CC	CC Recent	Generic unit	2014-05-01	-	570
OTC_R BV12 CC	CC Recent	Generic unit	2020-12-31	-	430
OTC_R LA12 CC	CC Recent	Generic unit	2020-12-31	-	435
OTC_R LA34 CC1	CC Recent	Generic unit	2020-12-31	-	600
OTC_R LA34 CC2	CC Recent	Generic unit	2020-12-31	-	600
OTC_R LA34 CT1a	CT Future	Generic unit	2020-12-31	-	100
OTC_R LA34 CT2a	CT Future	Generic unit	2020-12-31	-	100
OTC_R LA34 CT3a	CT Future	Generic unit	2020-12-31	-	100
OTC_R LA34 CT4a	CT Future	Generic unit	2020-12-31	-	100
OTC_R LA34 CT5a	CT Future	Generic unit	2020-12-31	-	100
OTC_R LA34 CT6a	CT Future	Generic unit	2020-12-31	-	100
OTC_R LA34 CT1b	CT Future	Generic unit	2020-12-31	-	100
OTC_R LA34 CT2b	CT Future	Generic unit	2020-12-31	-	100
OTC_R LA34 CT3b	CT Future	Generic unit	2020-12-31	-	100
OTC_R LA34 CT4b	CT Future	Generic unit	2020-12-31	-	100
OTC_R LA34 CT5b	CT Future	Generic unit	2020-12-31	-	100
OTC_R LA34 CT6b	CT Future	Generic unit	2020-12-31	-	100
OTC_R LA34 CT7a	CT Future	Generic unit	2020-12-31	-	100
OTC_R LA34 CT7b	CT Future	Generic unit	2020-12-31	-	100
OTC_R LA34 CT8a	CT Future	Generic unit	2020-12-31	-	100
OTC_R LA34 CT8b	CT Future	Generic unit	2020-12-31	-	100
OTC_R LA34 CT9	CT Future	Generic unit	2020-12-31	-	100

+4,835 MW

South CA OTC retirement and replacement assumptions

SDG&E area

Name	Type	Long Name	Commission Date	Retirement Date	MaxCap(MW)
Encina1	Steam Large Old	Encina 1 Carlsbad CA	1954-11-01	2016-06-30	106
Encina2	Steam Large Old	Encina 2 Carlsbad CA	1956-07-01	2016-06-30	103
Encina3	Steam Large Old	Encina 3 Carlsbad CA	1958-08-01	2016-06-30	109
Encina4	Steam Large Recent	Encina 4 Carlsbad CA	1973-11-01	2016-06-30	299
Encina5	Steam Large Recent	Encina 5 Carlsbad CA	1978-11-01	2016-06-30	329
SouthBy1	Steam Large Old	South Bay 1 Chula Vista CA	1962-06-01	2010-12-31	146
SouthBy2	Steam Large Old	South Bay 2 Chula Vista CA	1962-06-01	2010-12-31	149
SouthBy3	Steam Large Old	South Bay 3 Chula Vista CA	1964-09-01	2009-12-31	180
SouthBy4	Steam Large Old	South Bay 4 Chula Vista CA	1971-12-01	2009-12-31	222
Carlsbad Energy CC1	CC Recent	Carlsbad Energy Center CC1	2016-09-01	-	279
Carlsbad Energy CC2	CC Recent	Carlsbad Energy Center CC2	2016-09-01	-	279
OTC_R SD12 CT1	CT Future	Generic unit	2018-01-01	-	100
OTC_R SD12 CT2	CT Future	Generic unit	2018-01-01	-	100
OTC_R SD12 CT3	CT Future	Generic unit	2018-01-01	-	100
OTC_R SD12 CT4	CT Future	Generic unit	2018-01-01	-	100

+958 MW

Natural gas prices (Year 2018)

Based on CEC 2013 IEPR Preliminary

Area ID	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Avg
NG - AB	3.68	3.47	3.40	3.50	3.62	3.67	3.71	3.43	3.39	3.51	3.78	3.82	3.58
NG - AZ North	4.10	3.88	3.80	3.92	4.04	4.09	4.15	3.85	3.80	3.94	4.23	4.27	4.00
NG - AZ South	4.30	4.08	4.00	4.12	4.25	4.30	4.36	4.05	4.00	4.14	4.44	4.48	4.21
NG - BC	3.68	3.47	3.40	3.51	3.62	3.67	3.72	3.44	3.39	3.52	3.79	3.82	3.59
NG - BJ Rosarito	4.36	4.11	4.02	4.15	4.29	4.35	4.42	4.07	4.02	4.18	4.51	4.55	4.25
NG - CA Blythe	4.15	3.91	3.83	3.96	4.09	4.15	4.21	3.88	3.83	3.98	4.30	4.34	4.05
NG - CA Coolwater	4.15	3.91	3.83	3.96	4.09	4.15	4.21	3.88	3.83	3.98	4.30	4.34	4.05
NG - CA Kern River	4.15	3.91	3.83	3.96	4.09	4.15	4.21	3.88	3.83	3.98	4.30	4.34	4.05
NG - CA Mojave PL	4.15	3.91	3.83	3.96	4.09	4.15	4.21	3.88	3.83	3.98	4.30	4.34	4.05
NG - CA Otay Mesa	4.88	4.61	4.52	4.66	4.81	4.87	4.94	4.57	4.51	4.68	5.04	5.08	4.76
NG - CA PG&E BB	4.32	4.08	4.00	4.12	4.26	4.32	4.37	4.04	3.99	4.14	4.46	4.50	4.22
NG - CA PG&E LT	4.49	4.25	4.16	4.29	4.43	4.48	4.54	4.21	4.16	4.31	4.63	4.67	4.38
NG - CA S Cal Prod	4.68	4.42	4.33	4.46	4.61	4.67	4.74	4.38	4.33	4.49	4.83	4.88	4.57
NG - CA SCG	4.68	4.42	4.33	4.46	4.61	4.67	4.74	4.38	4.33	4.49	4.83	4.88	4.57
NG - CA SDG&E	4.88	4.61	4.52	4.66	4.81	4.87	4.94	4.57	4.51	4.68	5.04	5.08	4.76
NG - CA SMUD	4.32	4.07	3.99	4.12	4.25	4.31	4.37	4.04	3.99	4.14	4.46	4.50	4.21
NG - CA TEOR Cogen	4.26	4.01	3.93	4.05	4.19	4.25	4.31	3.97	3.92	4.08	4.40	4.44	4.15
NG - CO	4.02	3.80	3.73	3.84	3.97	4.02	4.07	3.78	3.73	3.86	4.15	4.19	3.93
NG - ID	3.71	3.50	3.43	3.53	3.65	3.70	3.74	3.46	3.41	3.54	3.81	3.85	3.61
NG - ID Kingsgate	3.83	3.62	3.55	3.66	3.78	3.82	3.87	3.59	3.54	3.67	3.94	3.97	3.74
NG - MT	3.92	3.71	3.64	3.75	3.86	3.91	3.96	3.68	3.63	3.76	4.04	4.07	3.83
NG - NM North	3.92	3.71	3.64	3.75	3.86	3.92	3.97	3.68	3.64	3.77	4.04	4.08	3.83
NG - NM South	4.01	3.80	3.72	3.83	3.96	4.01	4.06	3.77	3.72	3.85	4.13	4.17	3.92
NG - NV North	4.26	4.03	3.95	4.07	4.20	4.25	4.31	3.99	3.94	4.08	4.39	4.43	4.16
NG - NV South	4.50	4.26	4.18	4.31	4.45	4.50	4.56	4.23	4.18	4.33	4.65	4.69	4.40
NG - OR	3.81	3.59	3.52	3.63	3.75	3.80	3.86	3.55	3.51	3.64	3.93	3.97	3.71
NG - OR Malin	3.84	3.62	3.54	3.65	3.78	3.83	3.88	3.58	3.53	3.67	3.96	4.00	3.74
NG - TX West	3.80	3.59	3.52	3.63	3.75	3.80	3.85	3.56	3.52	3.65	3.93	3.96	3.71
NG - UT	4.44	4.23	4.16	4.27	4.39	4.44	4.50	4.20	4.16	4.29	4.57	4.61	4.36
NG - WA	4.03	3.81	3.73	3.85	3.97	4.02	4.07	3.77	3.72	3.86	4.14	4.18	3.93
NG - WY	4.02	3.80	3.73	3.84	3.96	4.01	4.07	3.77	3.73	3.86	4.14	4.18	3.93

2012$/MMBtu

Natural gas prices (Year 2023)

Based on CEC 2013 IEPR Preliminary

Area ID	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Avg
NG - AB	3.69	3.48	3.41	3.51	3.63	3.68	3.73	3.45	3.41	3.55	3.82	3.87	3.60
NG - AZ North	4.17	3.95	3.87	3.98	4.11	4.17	4.23	3.93	3.89	4.03	4.33	4.38	4.09
NG - AZ South	4.36	4.13	4.05	4.17	4.30	4.36	4.42	4.11	4.07	4.22	4.53	4.57	4.27
NG - BC	3.70	3.48	3.41	3.51	3.63	3.68	3.74	3.45	3.41	3.55	3.83	3.87	3.60
NG - BJ Rosarito	4.47	4.21	4.12	4.25	4.40	4.46	4.53	4.18	4.14	4.30	4.65	4.70	4.37
NG - CA Blythe	4.27	4.02	3.94	4.07	4.20	4.27	4.33	4.00	3.96	4.12	4.45	4.50	4.18
NG - CA Coolwater	4.27	4.02	3.94	4.07	4.20	4.27	4.33	4.00	3.96	4.12	4.45	4.50	4.18
NG - CA Kern River	4.27	4.02	3.94	4.07	4.20	4.27	4.33	4.00	3.96	4.12	4.45	4.50	4.18
NG - CA Mojave PL	4.27	4.02	3.94	4.07	4.20	4.27	4.33	4.00	3.96	4.12	4.45	4.50	4.18
NG - CA Otay Mesa	4.97	4.69	4.59	4.73	4.88	4.96	5.03	4.66	4.61	4.78	5.16	5.21	4.86
NG - CA PG&E BB	4.40	4.15	4.07	4.19	4.33	4.40	4.47	4.13	4.09	4.25	4.58	4.64	4.31
NG - CA PG&E LT	4.56	4.31	4.23	4.35	4.49	4.56	4.62	4.29	4.24	4.40	4.74	4.79	4.47
NG - CA S Cal Prod	4.77	4.50	4.41	4.54	4.69	4.76	4.83	4.47	4.42	4.59	4.95	5.00	4.66
NG - CA SCG	4.77	4.50	4.41	4.54	4.69	4.76	4.83	4.47	4.42	4.59	4.95	5.00	4.66
NG - CA SDG&E	4.97	4.69	4.59	4.73	4.88	4.96	5.03	4.66	4.61	4.78	5.16	5.21	4.86
NG - CA SMUD	4.40	4.15	4.06	4.19	4.33	4.40	4.46	4.13	4.08	4.24	4.58	4.63	4.30
NG - CA TEOR Cogen	4.38	4.12	4.04	4.16	4.31	4.37	4.44	4.10	4.05	4.22	4.56	4.61	4.28
NG - CO	4.09	3.87	3.79	3.90	4.02	4.08	4.14	3.84	3.80	3.94	4.24	4.28	4.00
NG - ID	3.72	3.51	3.43	3.54	3.65	3.71	3.76	3.48	3.44	3.57	3.85	3.89	3.63
NG - ID Kingsgate	3.84	3.62	3.55	3.66	3.77	3.82	3.88	3.60	3.56	3.69	3.97	4.01	3.75
NG - MT	3.96	3.75	3.67	3.78	3.90	3.95	4.01	3.72	3.68	3.82	4.10	4.15	3.87
NG - NM North	3.99	3.77	3.70	3.81	3.93	3.99	4.04	3.76	3.72	3.85	4.14	4.19	3.91
NG - NM South	4.06	3.84	3.76	3.87	3.99	4.05	4.11	3.82	3.78	3.92	4.21	4.25	3.97
NG - NV North	4.32	4.08	4.00	4.12	4.25	4.31	4.37	4.05	4.01	4.16	4.48	4.53	4.22
NG - NV South	4.61	4.36	4.27	4.40	4.54	4.60	4.67	4.34	4.29	4.45	4.79	4.84	4.51
NG - OR	3.86	3.64	3.56	3.67	3.79	3.85	3.91	3.61	3.57	3.71	4.01	4.05	3.77
NG - OR Malin	3.91	3.68	3.60	3.72	3.84	3.90	3.96	3.66	3.62	3.76	4.07	4.11	3.82
NG - TX West	3.86	3.64	3.57	3.68	3.80	3.85	3.91	3.62	3.58	3.72	4.01	4.05	3.77
NG - UT	4.49	4.27	4.19	4.30	4.43	4.48	4.54	4.25	4.20	4.35	4.64	4.68	4.40
NG - WA	4.06	3.83	3.76	3.87	3.99	4.05	4.11	3.81	3.77	3.91	4.21	4.25	3.97
NG - WY	4.09	3.86	3.79	3.90	4.02	4.08	4.14	3.84	3.80	3.94	4.24	4.28	4.00

2012$/MMBtu

Load (Year 2018 and 2023)

Based on CEC 2011 IEPR and WECC LRS 2012 forecast data

Area	Region	2018 energy (GWh)	2018 peak (MW)	2023 energy (GWh)	2023 peak (MW)
AESO	AB_AESO	102,221	14,186	116,692	16,208
BCH	BC_BCHA	67,167	12,062	68,356	12,333
FAR EAST	BS_IPCO	3,177	595	3,260	614
MAGIC VLY	BS_IPCO	5,038	1,186	5,197	1,223
TREAS VLY	BS_IPCO	10,536	2,276	11,120	2,466
PACE_ID	BS_PACE	4,235	830	4,327	845
PACE_UT	BS_PACE	34,995	7,844	37,643	8,487
PACE_WY	BS_PACE	13,066	1,730	14,145	1,886
SMUD	CA_BANC	18,530	4,831	19,871	5,130
CFE	CA_CFE	12,700	2,663	13,670	2,958
PG&E_BAY	CA_CISO	49,144	9,357	51,422	9,878
PG&E_VLY	CA_CISO	58,731	13,181	61,556	13,953
SCE	CA_CISO	102,887	24,235	106,975	25,688
SDGE	CA_CISO	23,304	5,068	25,275	5,441
VEA	CA_CISO	505	124	505	124
IID	CA_IID	4,272	1,142	4,617	1,216
LDWP	CA_LDWP	31,146	7,334	33,353	7,814
TIDC	CA_TID	2,775	626	2,929	656
AVA	NW_AVA	14,161	2,478	15,210	2,669
BPA	NW_BPAT	57,972	11,259	60,802	11,749
CHPD	NW_CHPD	4,044	726	4,149	761
DOPD	NW_DOPD	1,667	367	1,844	405
GCPD	NW_GCPD	5,216	841	5,628	903
NWMT	NW_NWE	11,320	1,758	11,818	1,835
PACW	NW_PACW	21,887	4,079	22,308	4,142
PGN	NW_PGN	23,644	4,321	25,817	4,681
PSE	NW_PSE	25,921	5,308	26,621	5,424
SCL	NW_SCL	10,577	1,915	10,904	1,972
TPWR	NW_TPWR	5,386	989	5,650	1,023
WAUW	NW_WAUW	783	146	783	146
PSC	RM_PSC	43,304	7,663	45,017	7,872
WACM	RM_WACM	28,433	4,687	32,671	5,401
APS	SW_AZPS	37,511	7,600	43,707	8,618
EPE	SW_EPE	10,172	2,051	11,347	2,285
NEVP	SW_NVE	25,337	6,231	26,786	6,649
SPP	SW_NVE	15,096	2,538	15,538	2,611
PNM	SW_PNM	15,541	2,854	16,572	3,088
SRP	SW_SRP	31,766	7,214	35,505	7,955
TEP	SW_TEP	15,007	3,078	15,919	3,277
WALC	SW_WALC	11,195	1,941	11,622	2,017

Economic Planning Studies

Part 4: Preliminary Results

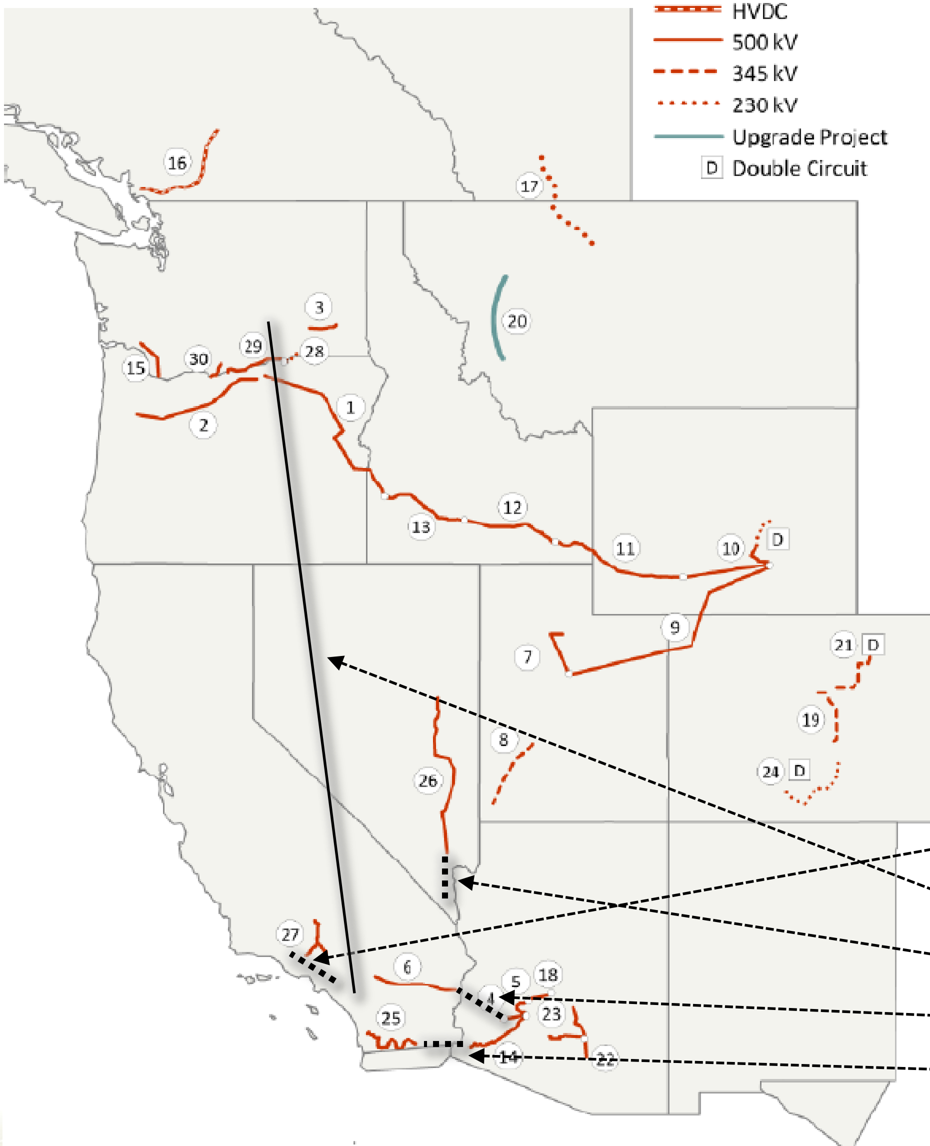
Xiaobo Wang, PhD
Regional Transmission Engineering Lead

ISO Transmission Planning Stakeholder Meeting
Folsom CA
November 21, 2013

Table of Contents

Subjects of economic planning studies

In a big picture



The red lines represent approved new transmission projects that are modeled in the TEPPC database

- 26 One Nevada Line, aka. ON-Line, (2013)
- 6 Colorado River – Valley line #2 (2013)
- 27 Tehachapi Renewable Transmission Project (2012-2013)
- 25 Sunrise Powerlink (2012)
- 14 Hassayampa – North Gila 500 kV line #2 (2015)

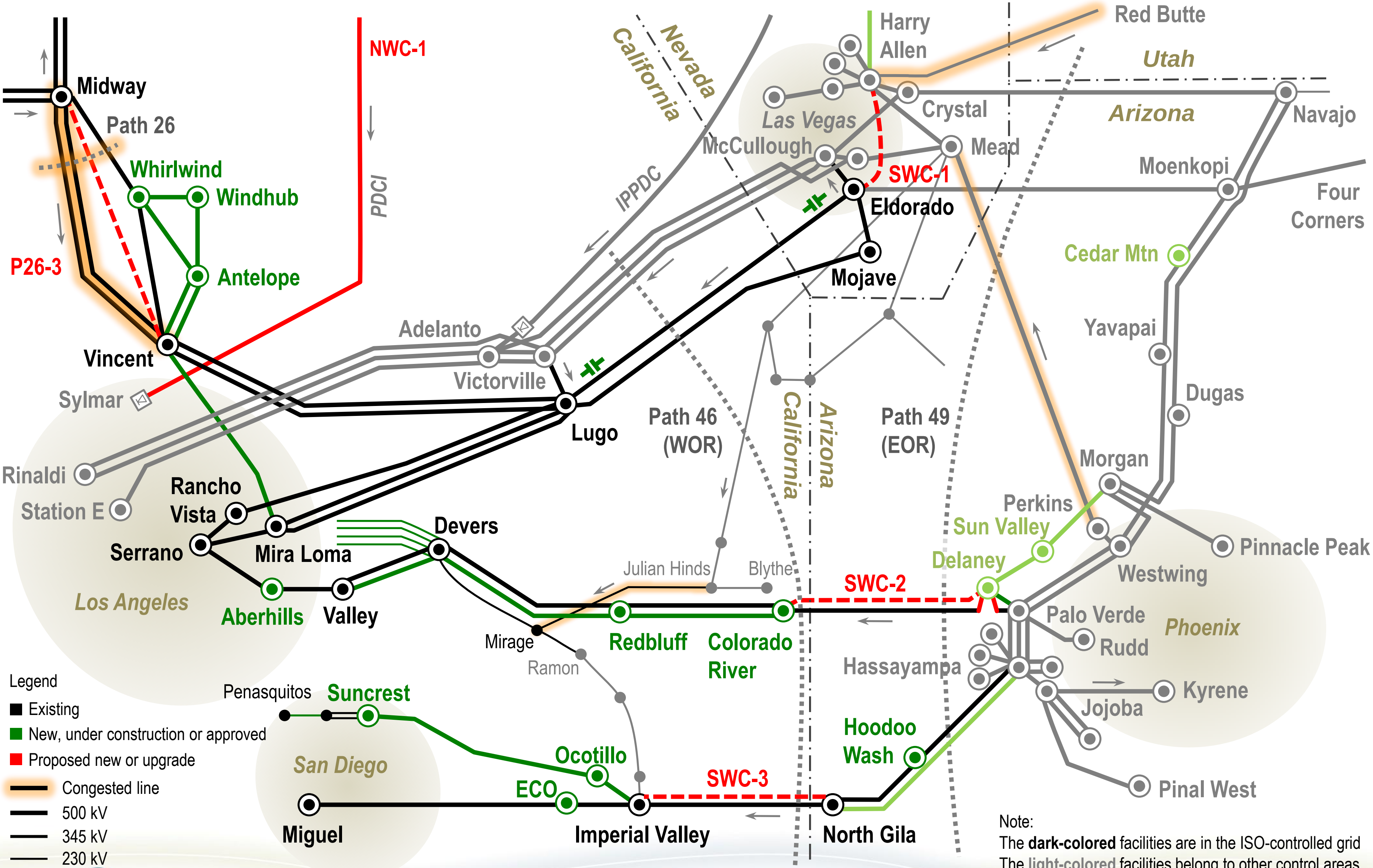
Five high-priority studies

#	ID	Proposed upgrade	Mileage
1	P26-3	Midway – Vincent 500 kV line #4	110
2	NWC-1	PDCI upgrade by 500 MW	-
3	SWC-1	Harry Allen – Eldorado 500 kV line	60
4	SWC-2	Delaney – Colorado River 500 kV line	110
5	SWC-3	North Gila – Imperial Valley 500 kV line #2	80

Source of the underlying map: “Common Case Transmission Assumptions”, WECC SPG Coordination Group, February 2012

Subjects of economic planning studies

A closer look



Note:
The **dark-colored** facilities are in the ISO-controlled grid
The light-colored facilities belong to other control areas

California ISO
Shaping a Renewed Future

Identified congestion and high priority studies

Simulated congestion in the ISO-controlled grid

#	Area	Congested transmission element	Congestion duration (hours)		Average congestion cost ($M)
			Year 2018	Year 2023	
1	PG&E and SCE	Path 26 (Midway – Vincent) ❶❷❸❹❺	878	545	6.890
2	SCE	North of Lugo (Kramer – Lugo 230 kV)	623	85	6.148
3	SCE	North of Lugo (Inyo 115 kV)	769	1,252	0.734
4	SCE and SDG&E	SCIT limits ❶❷❸❹❺	23	2	0.647
5	SCE	LA metro area	77	-	0.323
6	PG&E and PacifiCorp	Path 25 (PacifiCorp/PG&E 115 kV Interconnection) ❷	448	651	0.117
7	SCE	Mirage – Devers area ❶❷❸❹❺	83	7	0.080
8	SCE	Vincent 500 kV transformer ❶	6	4	0.037
9	PG&E	Greater Bay Area (GBA)	4	16	0.026
10	BPA and PG&E	Path 66 (COI) ❷	3	-	0.002

▲ Ranked by severity

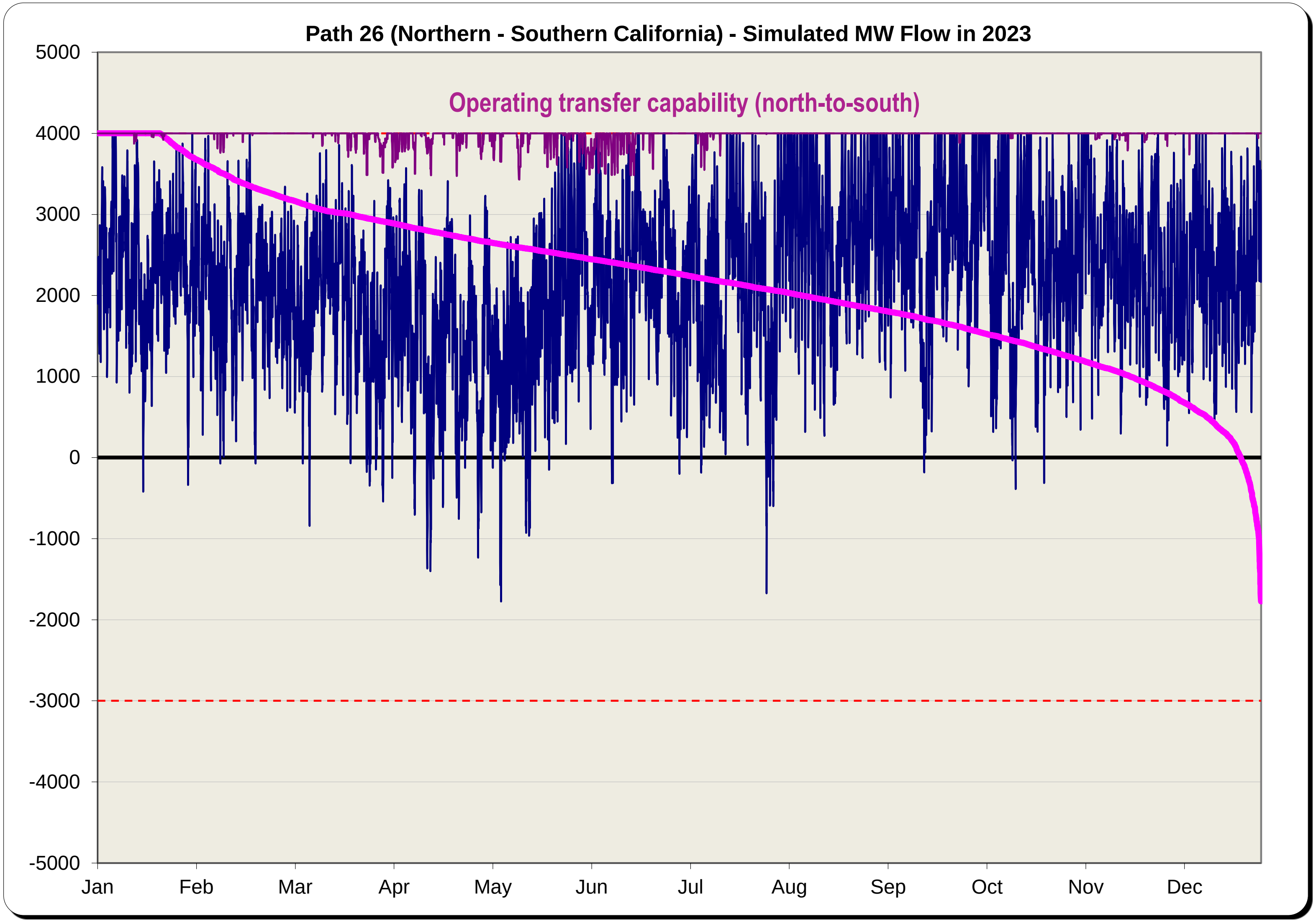
High priority studies

	Study ID	Study subject
❶	P26-3	Path 26 Northern - Southern CA
❷	NWC-1	PDCI upgrade
❸	SWC-1	Harry Allen – Eldorado 500 kV line
❹	SWC-2	Delaney – Colorado River 500 kV line
❺	SWC-3	North Gila – Imperial Valley 500 kV line #2

Note: With item #3, the congestion in the Control - Inyo – Kramer 115 kV system affects the geothermal generation in the area. Other than item #3, all other congestion does not affect renewables

Table of Contents

Simulated power flow on Path 26



Effects of congestion relief

With addition of the Midway – Vincent 500 kV line #4

2018:

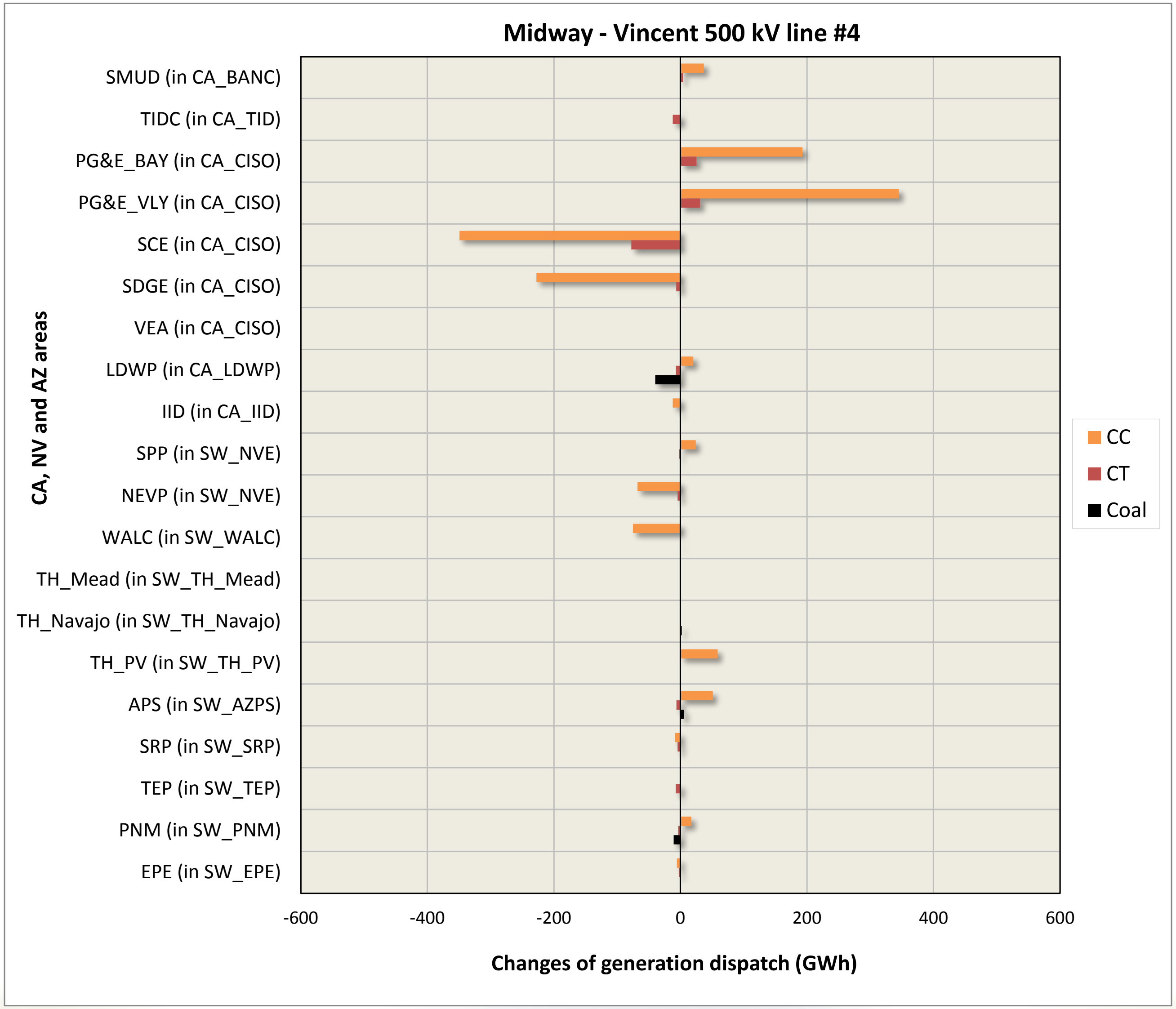
Transmission facility	Utility	Before	After	Change
Red Butte – Harry Allen 345 kV line	PacifiCorp – NVE	1,366	1,280	-86
Perkins – Mead 230 kV line	SRP/APS – WAPA	73	73	0
Path 26 (Midway – Vincent)	PG&E – SCE	878	158	-720
Vincent 500 kV transformer	SCE	6	106	+100
Julian Hinds – Mirage 230 kV line	SCE	83	91	+8
		2,406	1,708	-698

2023:

Transmission facility	Utility	Before	After	Change
Red Butte – Harry Allen 345 kV line	PacifiCorp – NVE	1,526	1,427	-99
Perkins – Mead 230 kV line	SRP/APS – WAPA	13	7	-6
Path 26 (Midway – Vincent)	PG&E – SCE	545	100	-445
Vincent 500 kV transformer	SCE	4	46	+42
Julian Hinds – Mirage 230 kV line	SCE	7	7	0
		2,095	1,587	-508

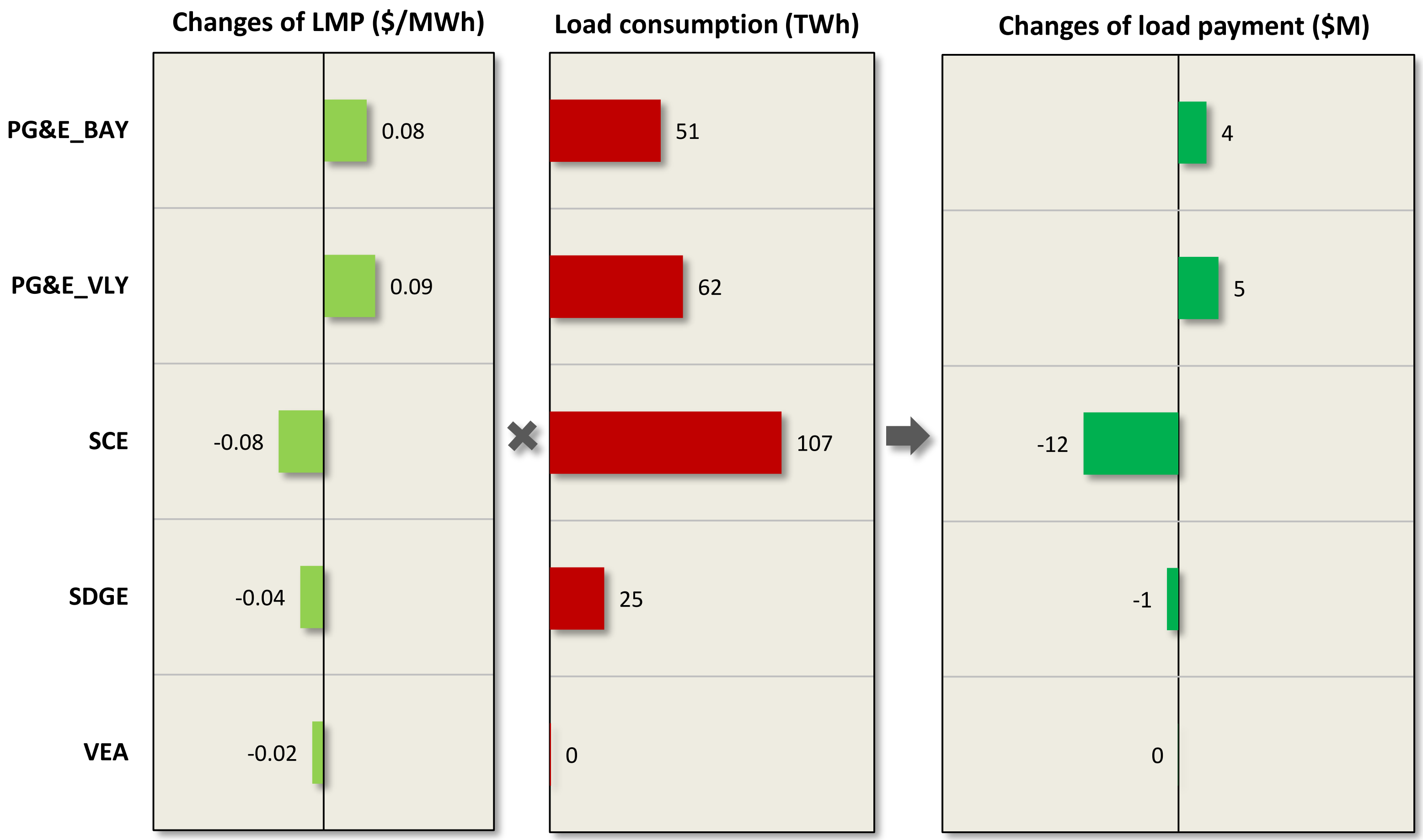
Incremental changes of generation dispatch

With addition of the Midway – Vincent 500 kV line #4



Load payment reductions in the ISO-controlled grid

With addition of the Midway – Vincent 500 kV line #4



Simulation year 2023

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

Determination of yearly production benefits

With addition of the Midway – Vincent 500 kV line #4

Year	Production		Part 1		Part 2
2018	-$5M	=	-$5M	+	$0M
2023	$3M	=	$3M	+	$0M

Where:

Part 1		Consumer	Producer	Transmission
-$5M	=	-$5M	$7M	-$7M
$3M	=	$3M	$5M	-$5M

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 * $40.15/MWh

Losses reduction estimated

Average LMP in 2023 in SCE area

California ISO
Shaping a Renewed Future

Determination of yearly capacity benefits

With addition of the Midway – Vincent 500 kV line #4

Capacity benefit is determined to be zero:

1. **System RA benefit is not applicable because this line is within the ISO**
2. **LCR benefit is not applicable**

Economic assessment for "P26-3"

Midway – Vincent 500 kV line #4

Million US$

	2018	2019	2020	2021	2022	2023	2024	2025	20xx
Production benefit	(4)	(2)	(1)	1	2	4	4	4	...
Capacity benefit	-	-	-	-	-	-	-	-	...
Total yearly benefit	(4)	(2)	(1)	1	2	4	4	4	...

Pushing off operation year ➔	2018	2019	2020	2021	2022	2023
Total benefit Sum of discounted yearly benefits	35	41	47	51	54	55
Total cost Total revenue requirement	1,595	1,595	1,595	1,595	1,595	1,595

1,100	Capital cost

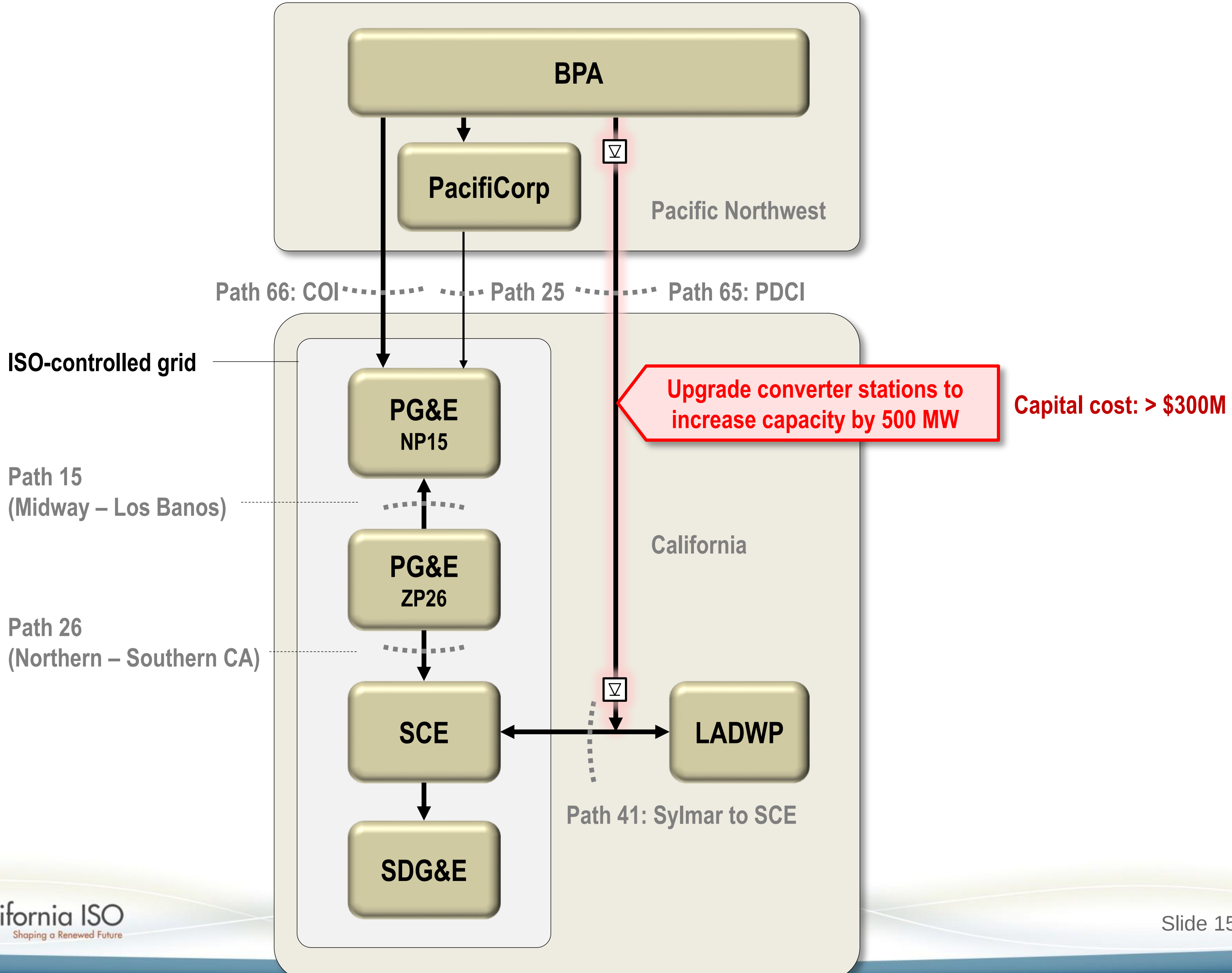
Net benefit	(1,560)	(1,554)	(1,548)	(1,544)	(1,541)	(1,540)
Benefit-cost ratio	0.02	0.03	0.03	0.03	0.03	0.03

California ISO
Shaping a Renewed Future

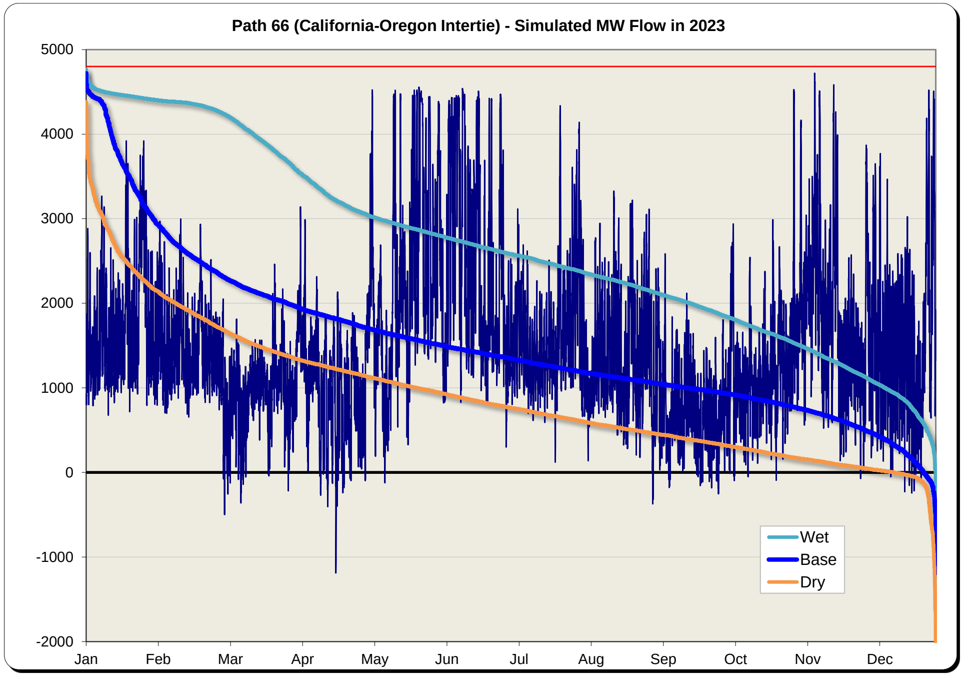
Table of Contents

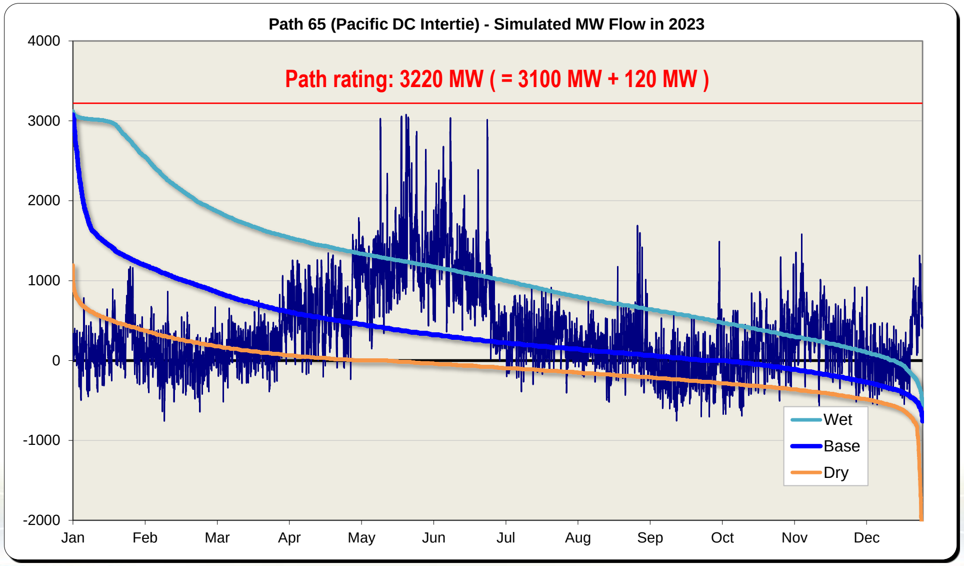
Pacific Northwest – California (NWC) area

PDCI upgrade



Simulated power flow on Path 66 (COI) and Path 65 (PDCI)





California ISO
Shaping a Renewed Future

Effects of congestion relief

With upgrade of PDCI by 500 MW rating increase

2018:

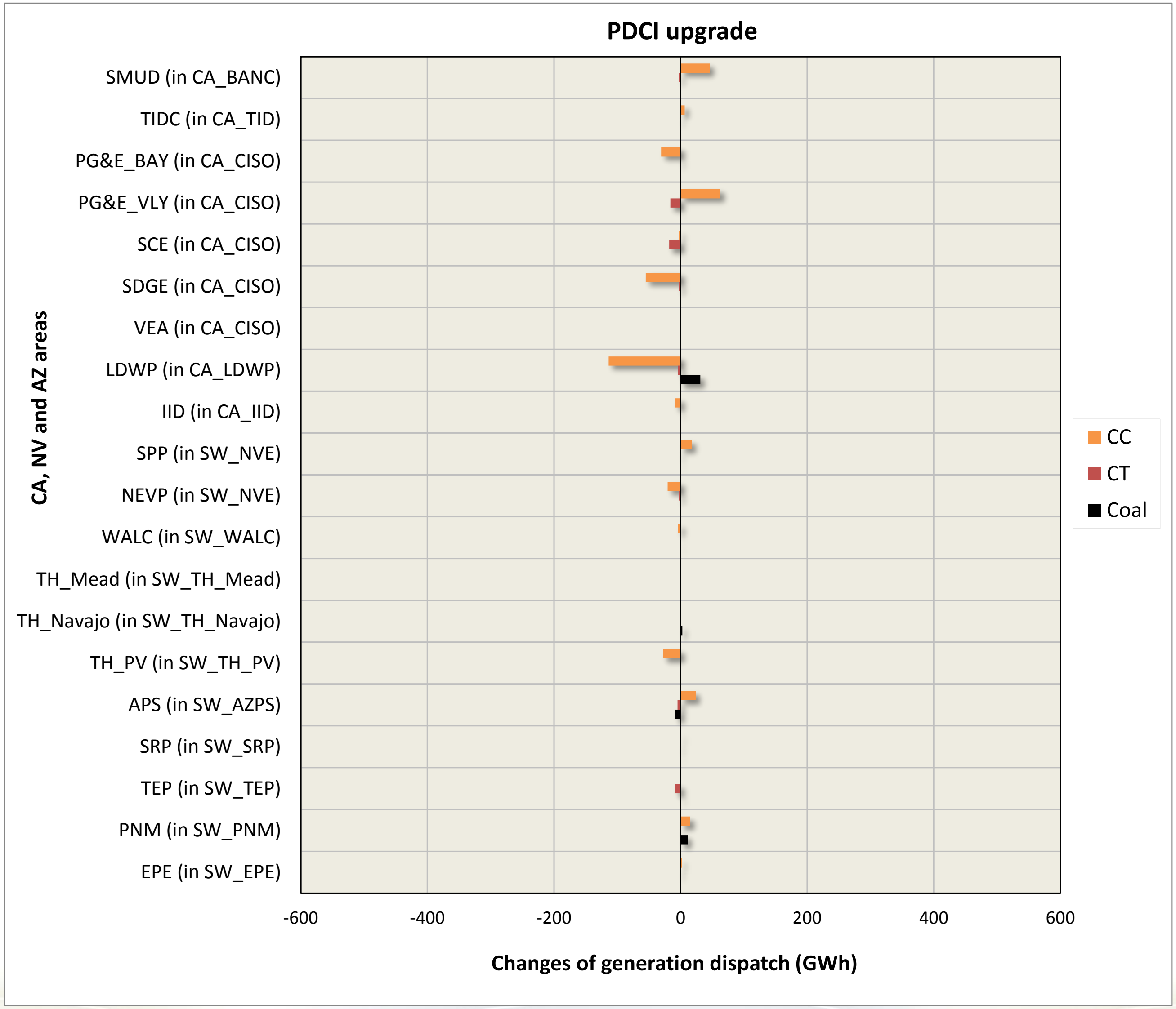
Transmission facility	Utility	Before	After	Change
Path 25 (PacifiCorp/PG&E 115 kV)	PacifiCorp – PG&E	448	477	+29
Red Butte – Harry Allen 345 kV line	PacifiCorp – NVE	1,366	1,283	-83
Perkins – Mead 230 kV line	SRP/APS – WAPA	73	72	-1
Path 26 (Midway – Vincent)	PG&E – SCE	878	831	-47
Julian Hinds – Mirage 230 kV line	SCE	83	74	-9
		2,848	2,737	-111

2023:

Transmission facility	Utility	Before	After	Change
Path 25 (PacifiCorp/PG&E 115 kV)	PacifiCorp – PG&E	651	640	-11
Red Butte – Harry Allen 345 kV line	PacifiCorp – NVE	1,526	1,564	+38
Perkins – Mead 230 kV line	SRP/APS – WAPA	13	11	-2
Path 26 (Midway – Vincent)	PG&E – SCE	545	544	-1
Julian Hinds – Mirage 230 kV line	SCE	7	5	-2
		2,742	2,754	-22

Incremental changes of generation dispatch

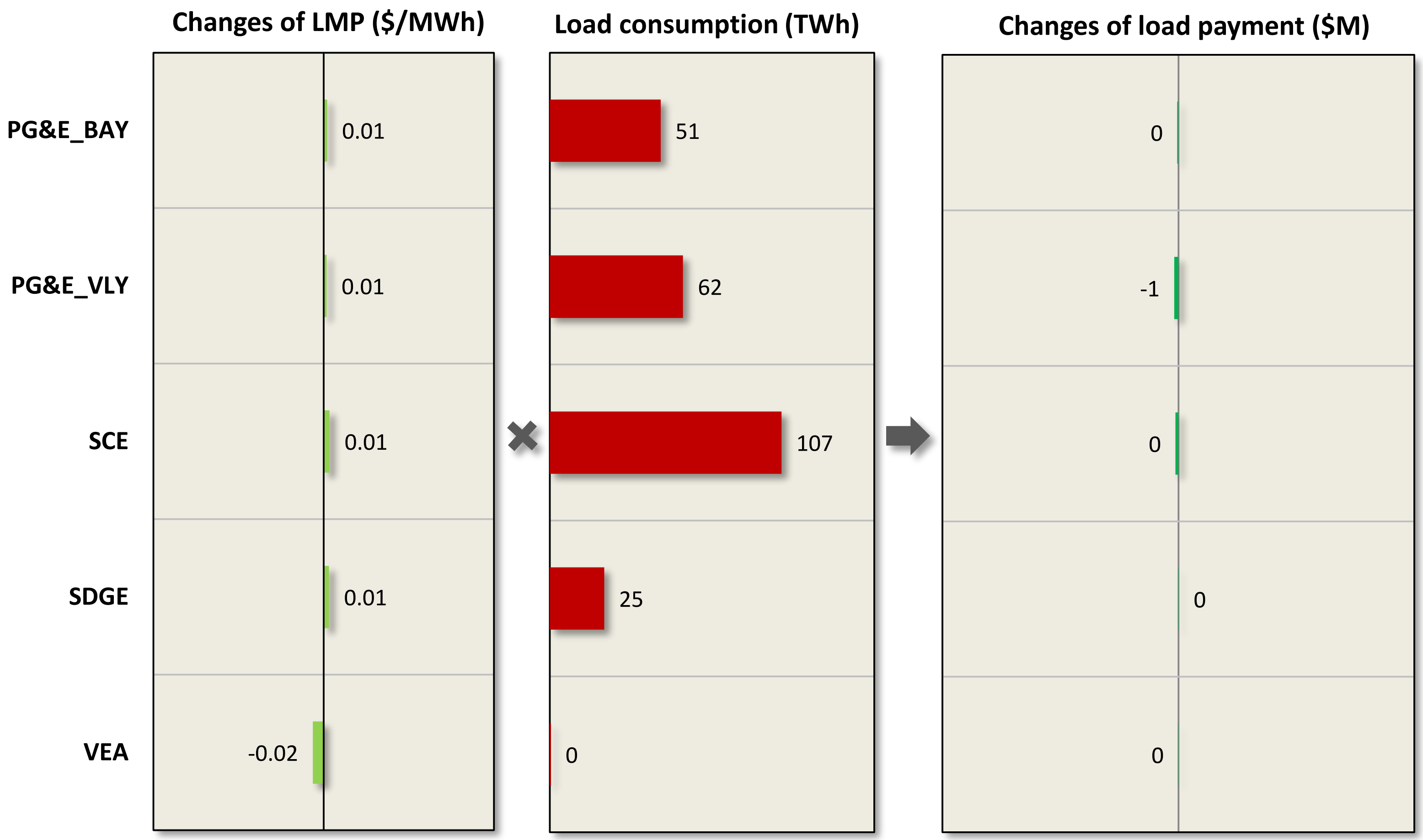
With upgrade of PDCI by 500 MW rating increase



Simulation year 2023

Load payment reductions in the ISO-controlled grid

With upgrade of PDCI by 500 MW rating increase



Simulation year 2023

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

Determination of yearly production benefits

With upgrade of PDCI by 500 MW rating increase

Year	Production		Part 1		Part 2
2018	$7M	=	$7M	+	$0M
2023	$3M	=	$3M	+	$0M

Where:

Part 1		Consumer	Producer	Transmission
$7M	=	$9M	-$1M	-$1M
$3M	=	$1M	$2M	$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 * $40.15/MWh

Losses reduction estimated

Average LMP in 2023 in SCE area

Determination of yearly capacity benefits

With upgrade of PDCI by 500 MW rating increase

Capacity benefit is estimated to be -$4M:

1. **System RA benefit is zero because of downstream bottleneck**
2. **LCR benefit is negative because of downstream bottleneck**

Cost-benefit analysis for "NWC-1"

Upgrade PDCI by 500 MW rating increase

Million US$

	2018	2019	2020	2021	2022	2023	2024	2025	20xx
Production benefit	7	6	5	4	4	3	3	3	…
Capacity benefit	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	…
Total yearly benefit	3	2	1	1	0	(1)	(1)	(1)	…

Assumed operation year →	2018
Total benefit Sum of discounted yearly benefits	(4)
Total cost Total revenue requirement	435

300	Capital cost

Net benefit	(439)
Benefit-cost ratio	-0.01

Table of Contents

Effects of congestion relief

With addition of the Harry Allen – Eldorado 500 kV line

2018:

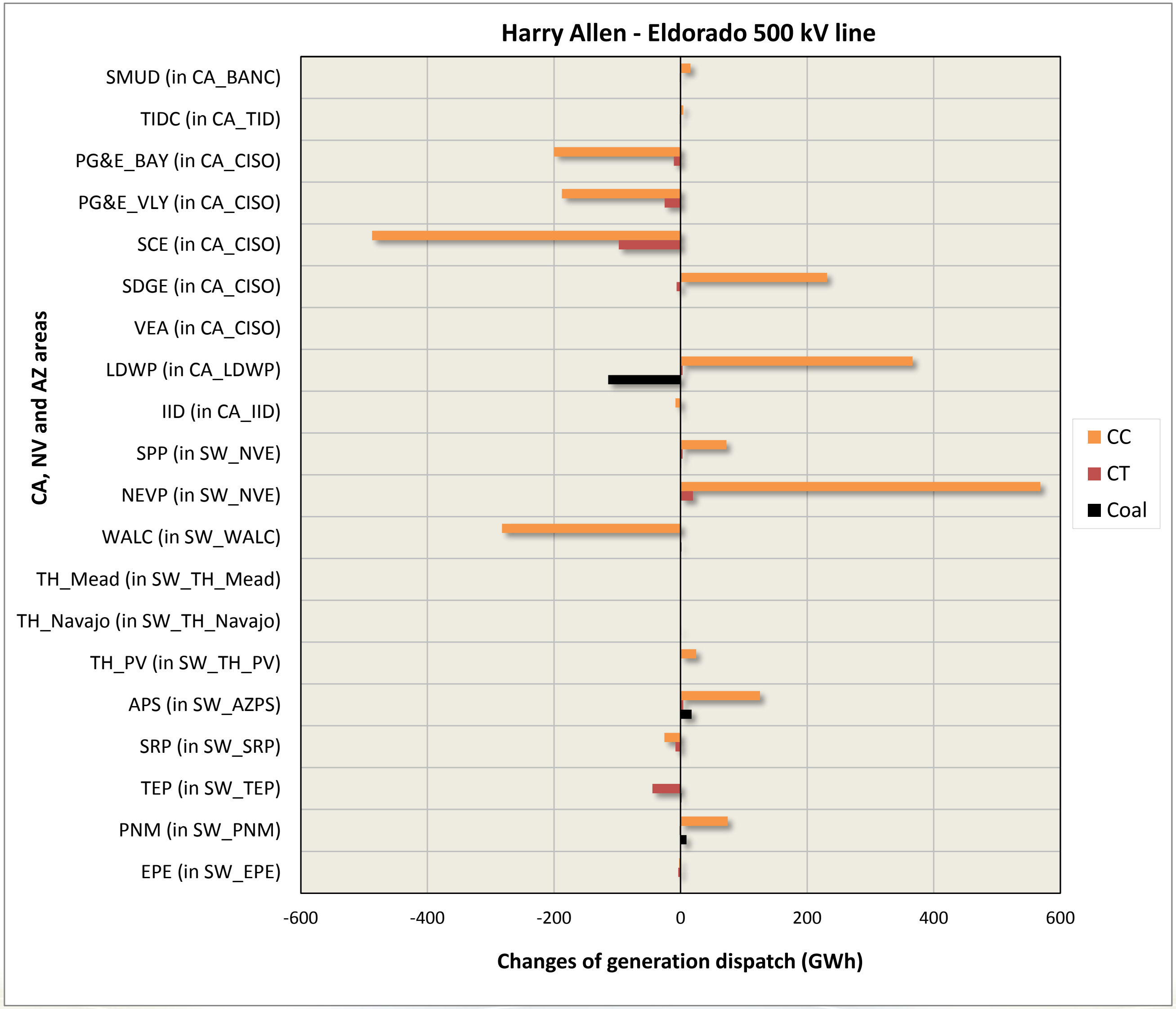
Transmission facility	Utility	Before	After	Change
Red Butte – Harry Allen 345 kV line	PacifiCorp – NVE	1,366	1,064	-302
Perkins – Mead 230 kV line	SRP/APS – WAPA	73	28	-45
Path 26 (Midway – Vincent)	PG&E – SCE	878	648	-230
Julian Hinds – Mirage 230 kV line	SCE	83	79	-4
		2,400	1,819	-581

2023:

Transmission facility	Utility	Before	After	Change
Red Butte – Harry Allen 345 kV line	PacifiCorp – NVE	1,526	1,194	-332
Perkins – Mead 230 kV line	SRP/APS – WAPA	13	5	-8
Path 26 (Midway – Vincent)	PG&E – SCE	545	387	-158
Julian Hinds – Mirage 230 kV line	SCE	7	14	+7
		2,091	1,600	-491

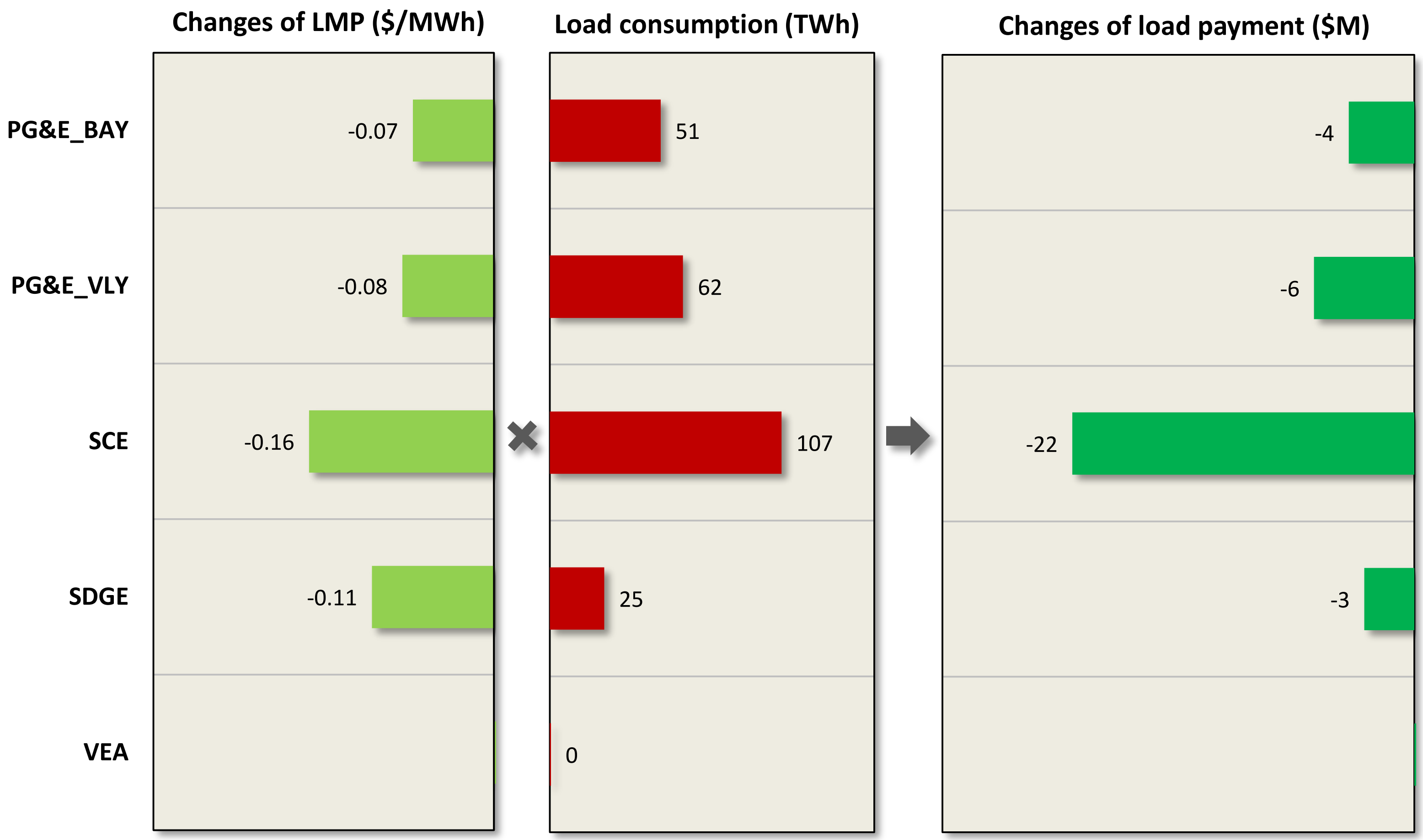
Incremental changes of generation dispatch

With addition of the Harry Allen – Eldorado 500 kV line



Load payment reductions in the ISO-controlled grid

With addition of the Harry Allen – Eldorado 500 kV line



Simulation year 2023

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

Determination of yearly production benefits

With addition of the Harry Allen – Eldorado 500 kV line

Year	Production		Part 1		Part 2
2018	-$3M	=	$3M	+	$0M
2023	$10M	=	$10M	+	$0M

Where:

Part 1		Consumer	Producer	Transmission
-$3M	=	$9M	-$2M	-$10M
$10M	=	$30M	-$4M	-$15M

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
$1M	=	~0 MW * 8760 hours * $40.15/MWh

Losses reduction estimated

Average LMP in 2023 in SCE area

Determination of yearly capacity benefits

With addition of the Harry Allen – Eldorado 500 kV line

Capacity benefit = RA capacity x ΔCapacity cost

Year	Capacity benefit	RA capacity (MW)	ΔCapacity cost ($M/kW-yr)	NV CT cost ($M/kW-yr)	SCE CT cost ($M/kW-yr)
2018	-	-	TBD	TBD	
2019	-	-	TBD	TBD	
2020	TBD	TBD	TBD	TBD	
2021	TBD	TBD	TBD	TBD	
2022	TBD	TBD	TBD	TBD	183
2023	TBD	TBD	TBD	TBD	
2024	TBD	TBD	TBD	TBD	
2025	TBD	TBD	TBD	TBD	

RA capacity: Incremental RA import capacity calculated by PSLF power flow

ΔCapacity cost: Difference between NV and SCE CT costs

NV CT cost: Market cost ($TBD in 2012) ramped up to fixed cost ($TBD in 20??)

Note:
The above capacity benefit is system RA benefit. LCR benefit is not applicable for this line.

Benefit-cost analysis for "SWC-1"

Harry Allen – Eldorado 500 kV line

Million US$

	2018	2019	2020	2021	2022	2023	2024	2025	20xx
Production benefit	(3)	0	2	5	7	10	10	10	…
Capacity benefit	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD	…
Total yearly benefit	(3)	0	2	5	7	10	10	10	…

TBD: The capacity benefits are being studied

Pushing off operation year →	2018	2019	2020	2021	2022	2023
Total benefits Sum of discounted yearly benefits	105	115	124	131	136	138
Total costs Total revenue requirement	174	174	174	174	174	174

120	Capital costs

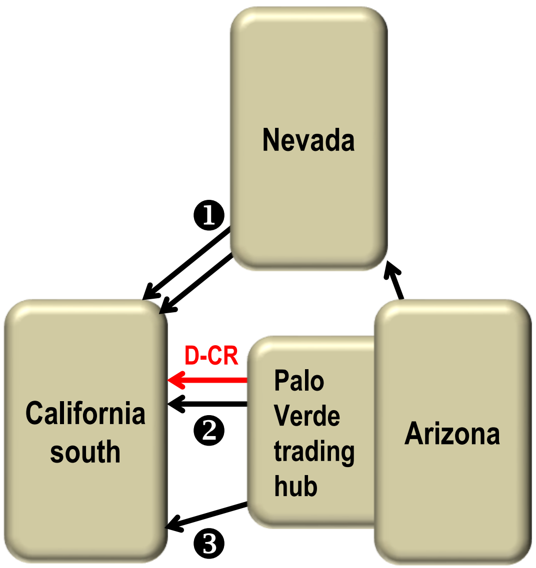
Net benefit	(69)	(59)	(50)	(43)	(38)	(36)
Benefit-cost ratio	0.60	0.66	0.71	0.75	0.78	0.79

California ISO
Shaping a Renewed Future

Table of Contents

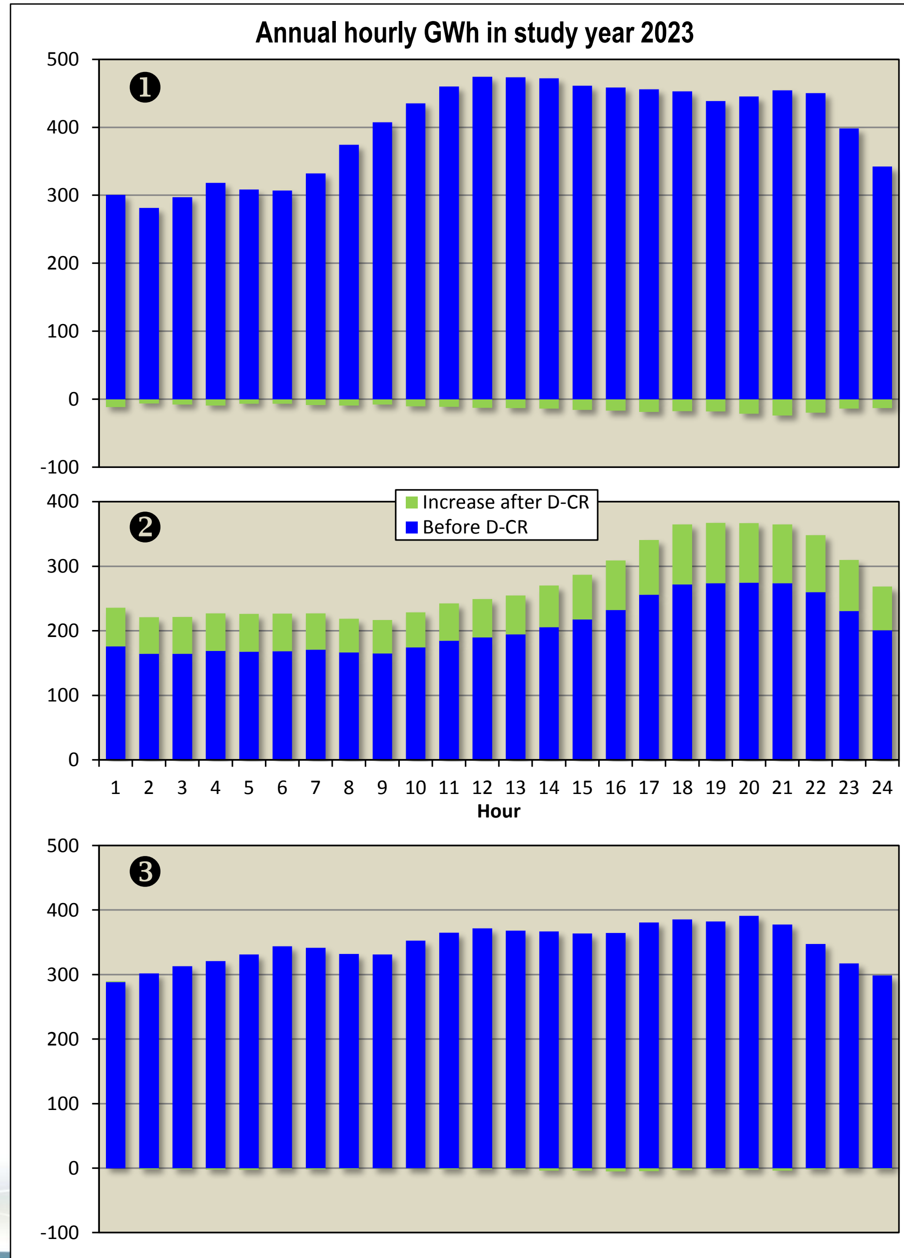
Imports from Southwest to Southern CA

Before and after the Delaney – Colorado River 500 kV line



500 kV transmission corridors:
❶ Eldorado to Lugo
❷ Palo Verde to Colorado River
❸ Palo Verde to Imperial Valley

The Palo Verde trading hub has the largest concentration of efficient generation in the Western Interconnection



Flow decrease

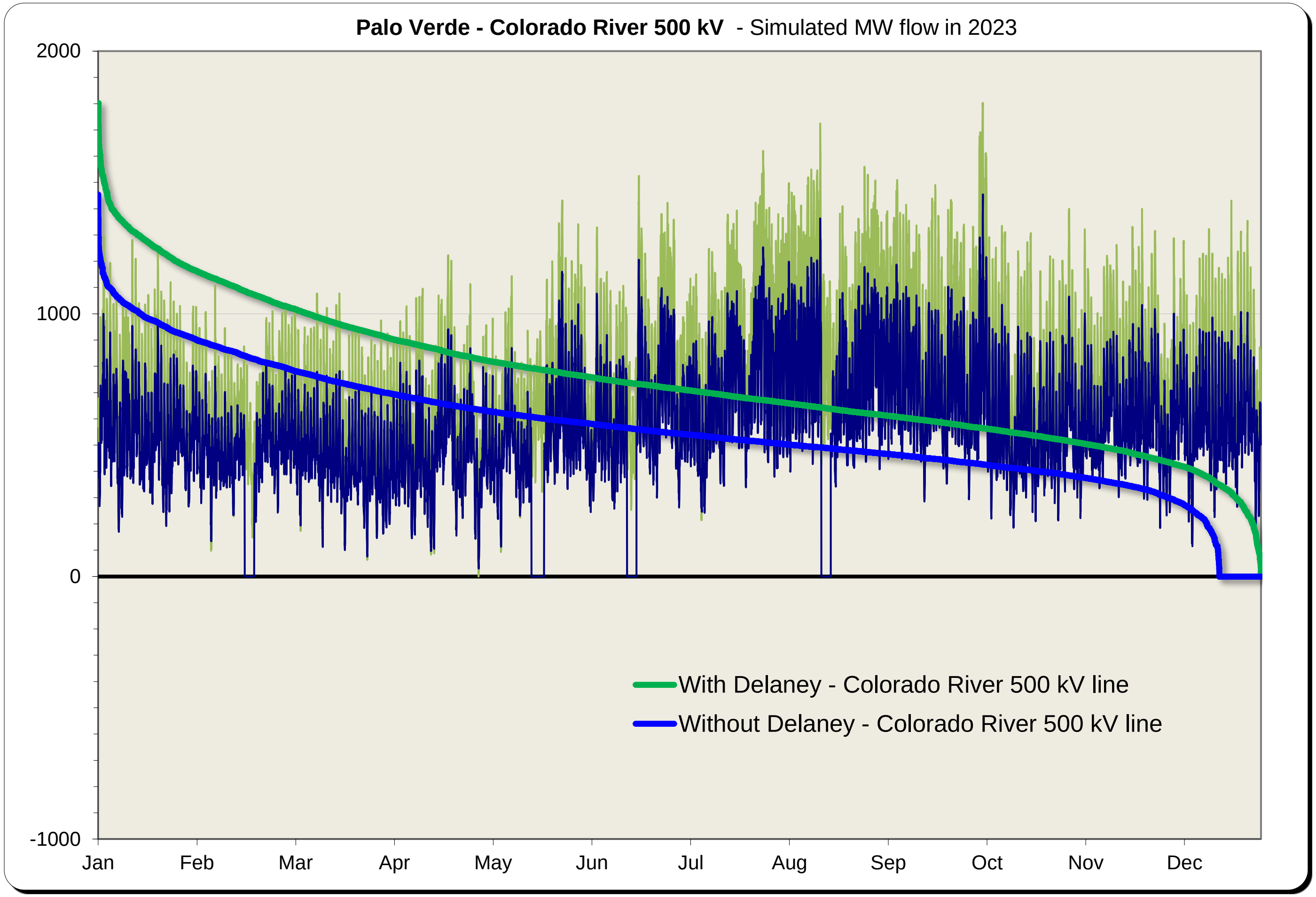
Flow increase

Incoming flow from Palo Verde hub at maximum after sunset

Flow decrease

Line flow from Palo Verde to Colorado River

Before and after the Delaney – Colorado River 500 kV line



The Delaney – Colorado River 500 kV line allows SCE area to:

1. **Have more efficient access to the Palo Verde trading hub**
2. **Have uninterrupted access to the Palo Verde hub under L-1 conditions**
3. **Receive 30% more dispatched energy via this transmission corridor**

Effects of congestion relief

With addition of the Delaney – Colorado River 500 kV line

2018:

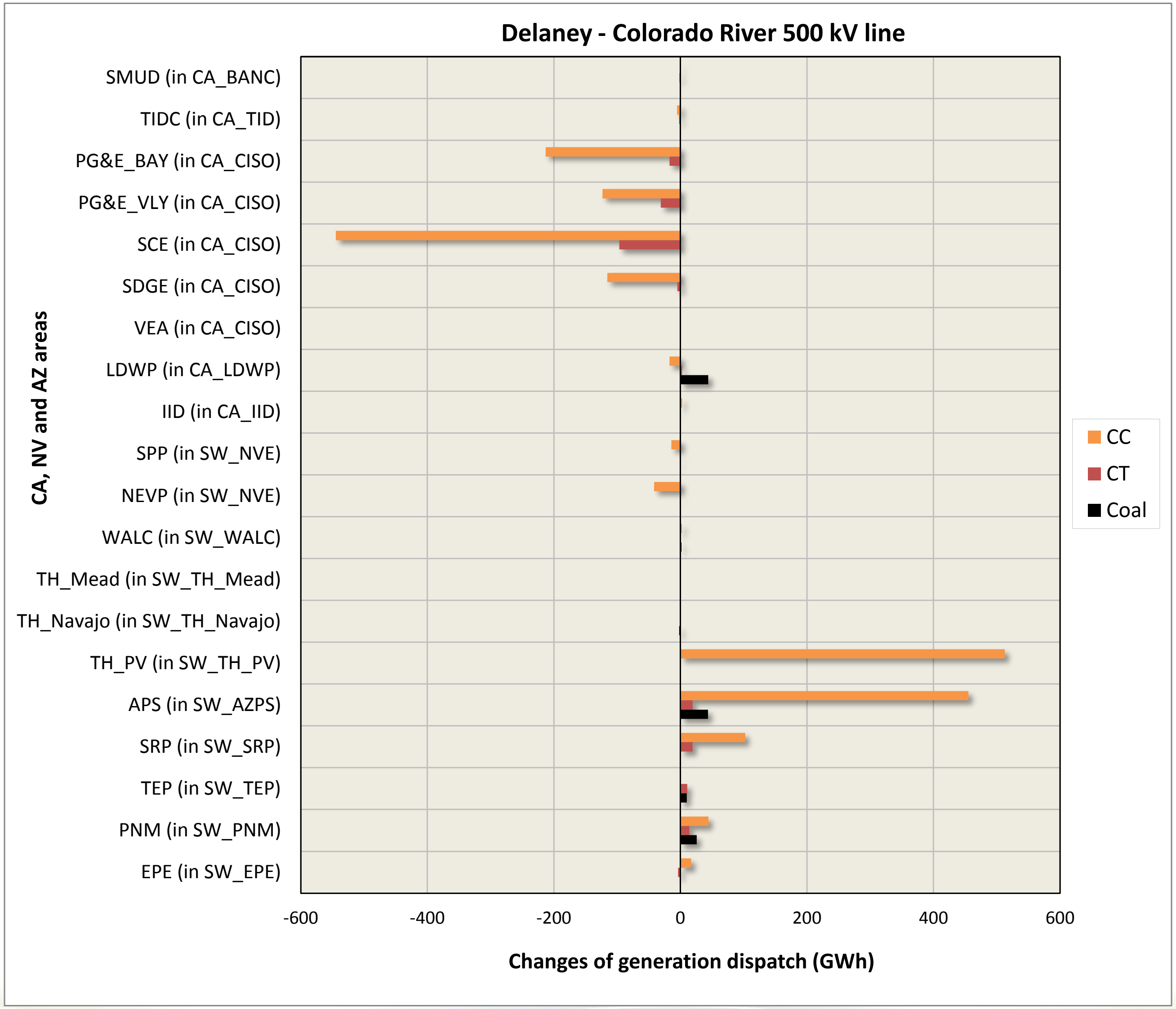
Transmission facility	Utility	Before	After	Change
Red Butte – Harry Allen 345 kV line	PacifiCorp – NVE	1,366	1,366	0
Perkins – Mead 230 kV line	SRP/APS – WAPA	73	39	-34
Path 26 (Midway – Vincent)	PG&E – SCE	878	768	-110
Julian Hinds – Mirage 230 kV line	SCE	83	2	-81
		2,400	2,175	-225

2023:

Transmission facility	Utility	Before	After	Change
Red Butte – Harry Allen 345 kV line	PacifiCorp – NVE	1,526	1,519	-7
Perkins – Mead 230 kV line	SRP/APS – WAPA	13	9	-4
Path 26 (Midway – Vincent)	PG&E – SCE	545	492	-53
Julian Hinds – Mirage 230 kV line	SCE	7	0	-7
		2,091	2,020	-71

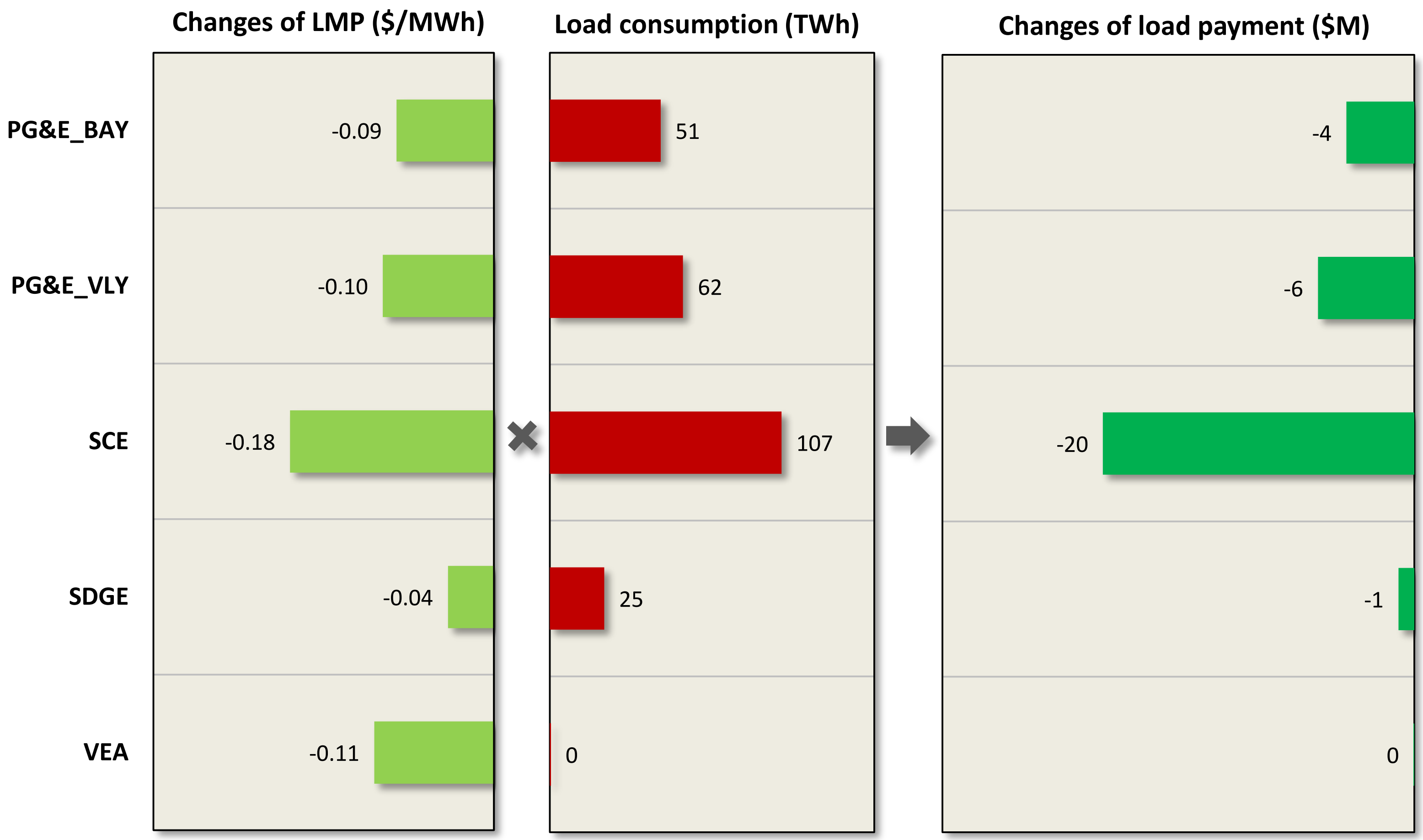
Incremental changes of generation dispatch

With addition of the Delaney – Colorado River 500 kV line



Load payment reductions in the ISO-controlled grid

With addition of the Delaney – Colorado River 500 kV line



Simulation year 2023

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

Determination of yearly production benefits

With addition of the Delaney – Colorado River 500 kV line

Year	Production		Part 1		Part 2
2018	$30M	=	$30M	+	$1M
2023	$25M	=	$25M	+	$1M

Where:

Part 1		Consumer	Producer	Transmission
$30M	=	$38M	-$5M	-$3M
$25M	=	$31M	-$4M	-$2M

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
$1M	=	3.62 MW * 8760 hours * $40.15/MWh

Losses reduction calculated by PSLF power flow

Average LMP in 2023 in SCE area

Determination of yearly capacity benefits

With addition of the Delaney – Colorado River 500 kV line

Year	Capacity benefit		RA capacity (MW)		ΔCapacity cost ($M/kW-yr)		AZ CT cost ($M/kW-yr)	SCE CT cost ($M/kW-yr)
2018	-		-		107		76	183
2019	-		-		98		86	
2020	$35M		400		88		95	
2021	$32M	=	400	x	79		104	
2022	$28M		400		69		114	
2023	$24M		400		60		123	
2024	$20M		400		51		133	
2025	$17M		400		41		142	

RA capacity: Incremental RA import capacity calculated by PSLF power flow

ΔCapacity cost: Difference between AZ and SCE CT costs

AZ CT cost: Market cost ($20 in 2012) ramped up to fixed cost ($142 in 2025)

See the next slide for further details

Note:
The above capacity benefit is system RA benefit. LCR benefit is not applicable for this line.

Determination of yearly capacity benefits (cont'd)

With addition of the Delaney – Colorado River 500 kV line

Assumptions for capacity benefits:

- Delaney – Colorado River transmission capacity is available in 2020 (internal limitations until then)
- California is resource deficit prior to 2020
- Desert Southwest becomes resource deficit in 2025
- Aero-derivative Combustion Turbines (CT) are the current and future choice of thermal peak capacity
- Aero CTs are more economical to build and operate in AZ compared to CA
  - $183/kw-yr vs. $142/kw-yr (2012 $, levelized)

California ISO
Shaping a Renewed Future

Cost-benefit analysis for "SWC-2"

Delaney – Colorado River 500 kV line

Million US$

	2018	2019	2020	2021	2022	2023	2024	2025	20xx
Production benefit	31	30	29	28	27	26	26	26	…
Capacity benefit	-	-	35	32	28	24	20	17	…
Total yearly benefit	31	30	82	75	69	62	56	51	…

Pushing off operation year →	2018	2019	2020
Total benefits Sum of discounted yearly benefits	616	630	645
Total costs Total revenue requirement	498	498	498

325	Build the new line
20	Loop in the existing line
345	**Capital costs** Sum of the two cost items

	2018	2019	2020
Net benefit	118	132	147
Benefit-cost ratio	1.24	1.26	1.30

Sensitivity analysis

Production benefits ($M) calculated by 8,760 hourly production simulation

#	Scenario description	Scenario ID	Year 2018	Year 2023
0	Base case	Base	30	25
1	Load high (+6%)	L+06	29	23
2	Load low (-6%)	L-06	14	20
3	Hydro high (2011 wet condition)	H_Wet	26	22
4	Hydro low (2001 dry condition)	H_Dry	34	11
5	Natural gas price high (+50%)	NG_H+50%	34	31
6	Natural gas price low (-25%)	NG_L-25%	22	14
7	GHG emission no model (No CO_2 tax)	GHG_N	23	24
8	GHG emission full model (WECC-wide CO_2 tax)	GHG_W	26	25
9	CA RPS 33% portfolio #2 (Environmental)	RPS_EC	29	23
10	CA RPS 33% portfolio #3 (High DG)	RPS_HD	30	21
11	Flexible reserve requirement high (+50%)	FR+50%	29	27
12	Flexible reserve requirement low (-50%)	FR-50%	28	24
13	Build the Harry Allen – Eldorado 500 kV line first	SWC-1	29	28
14	Build the North Gila – Imperial Valley 500 kV #2 first	SWC-3	28	25
15	Build the Midway – Vincent 500 kV line #4 first	P26-3	30	24

Sensitivity analysis (cont'd)

Cost-benefit analysis

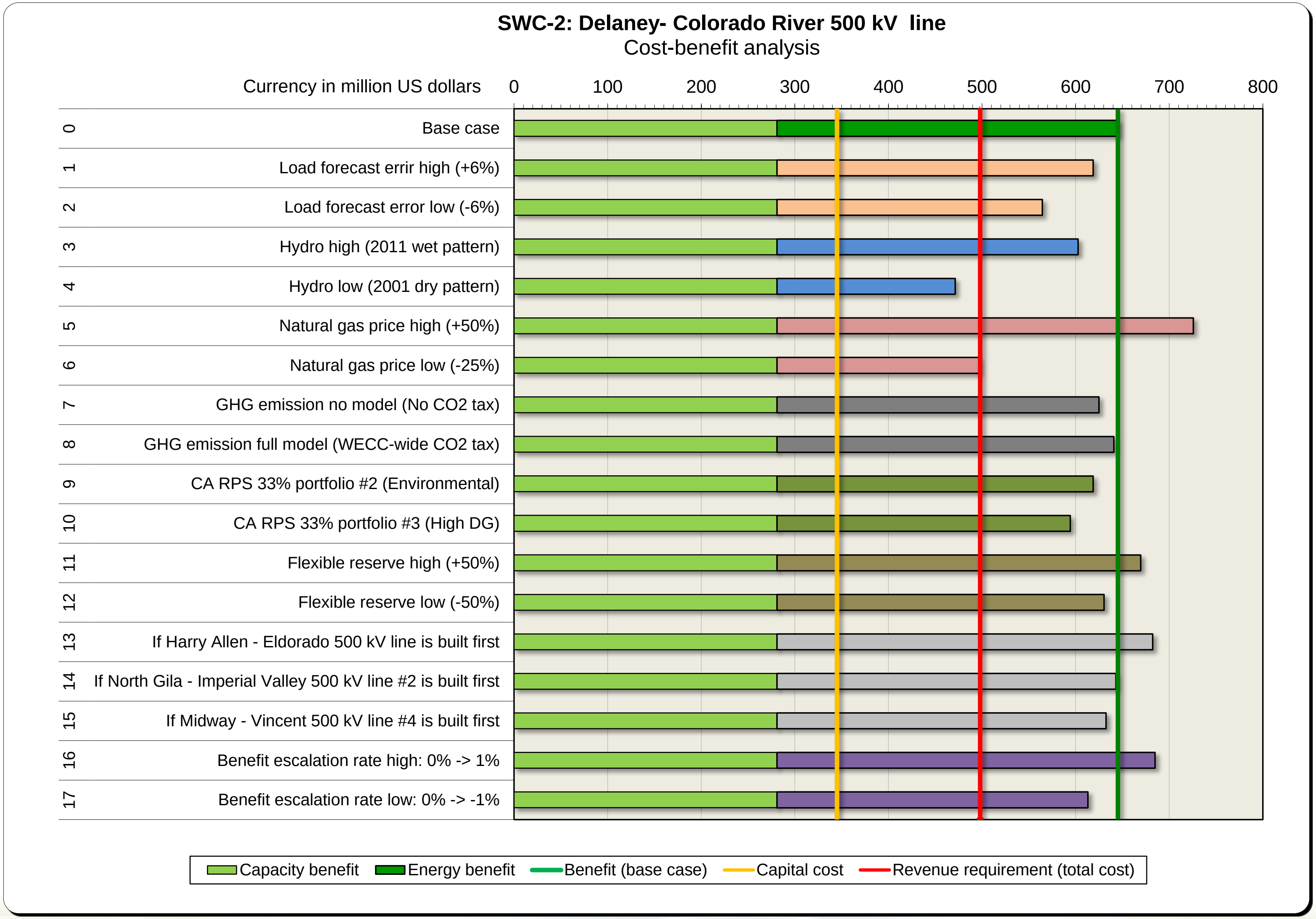


Table of Contents

Effects of congestion relief

With addition of the North Gila – Imperial Valley 500 kV line #2

2018:

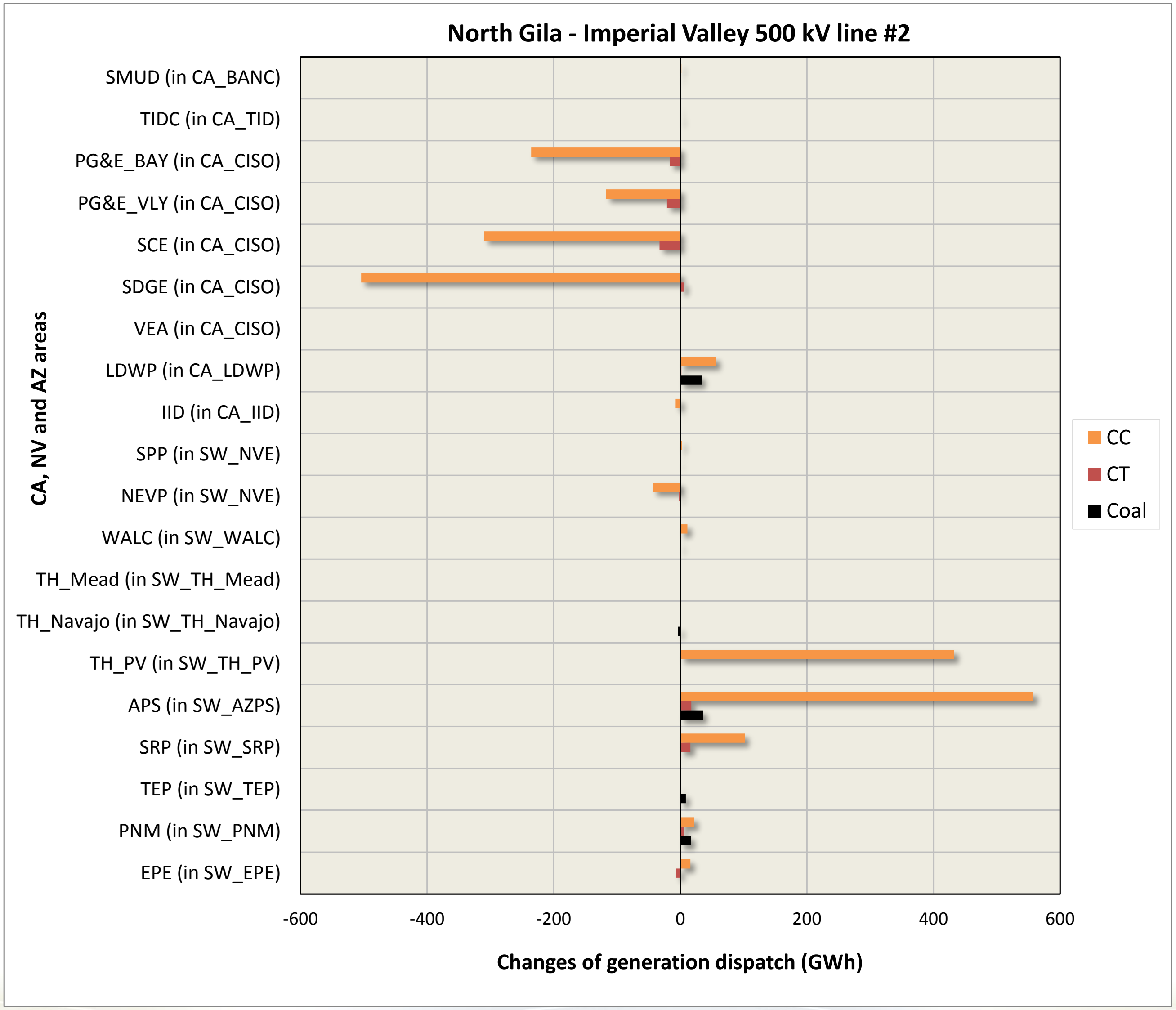
Transmission facility	Utility	Before	After	Change
Red Butte – Harry Allen 345 kV line	PacifiCorp – NVE	1,366	1,293	-73
Perkins – Mead 230 kV line	SRP/APS – WAPA	73	61	-12
Path 26 (Midway – Vincent)	PG&E – SCE	878	830	-48
Julian Hinds – Mirage 230 kV line	SCE	83	77	-6
		2,400	2,261	-139

2023:

Transmission facility	Utility	Before	After	Change
Red Butte – Harry Allen 345 kV line	PacifiCorp – NVE	1,526	1,519	-7
Perkins – Mead 230 kV line	SRP/APS – WAPA	13	10	-3
Path 26 (Midway – Vincent)	PG&E – SCE	545	496	-49
Julian Hinds – Mirage 230 kV line	SCE	7	5	-2
		2,091	2,030	-61

Incremental changes of generation dispatch

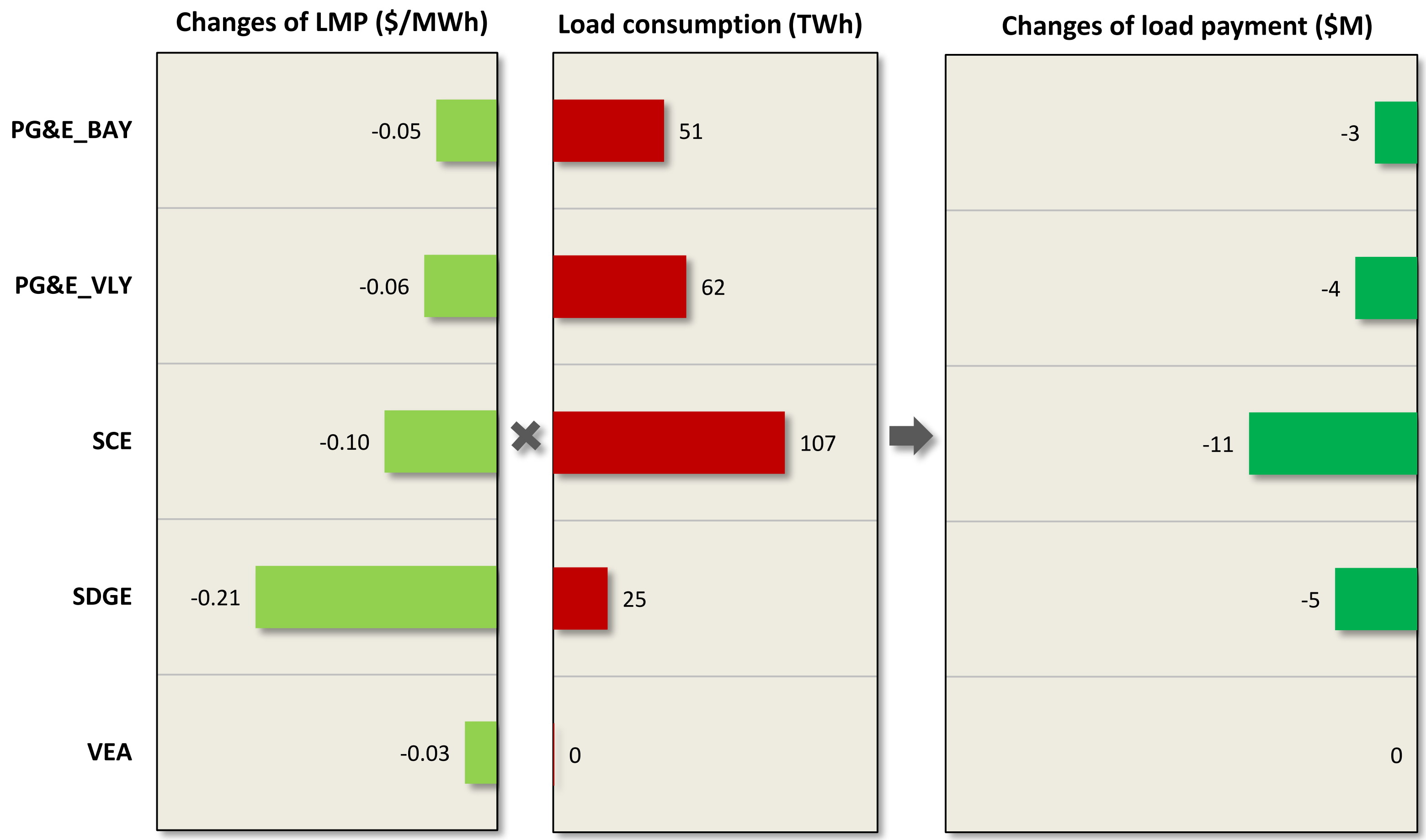
With addition of the North Gila – Imperial Valley 500 kV line #2



Simulation year 2023

Load payment reductions in the ISO-controlled grid

With addition of the North Gila – Imperial Valley 500 kV line #2



Simulation year 2023

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

Determination of yearly production benefits

With addition of the North Gila – Imperial Valley 500 kV line #2

Year	Production
2018	$21M
2023	$20M

=

Part 1
$21M
$20M

+

Part 2
$0M
$0M

Where:

Part 1
$21M
$20M

=

Consumer	Producer	Transmission
$22M	$0M	-$1M
$23M	-$2M	-$1M

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

Part 2
$0M

=

Losses reduction benefit
~0 MW * 8760 hours * $40.15/MWh

Losses reduction calculated by PSLF power flow

Average LMP in 2023 in SCE area

California ISO
Shaping a Renewed Future

Determination of yearly capacity benefits

With addition of the North Gila – Imperial Valley 500 kV line #2

Capacity benefit is determined to be zero:

1. **System RA benefit is zero because of downstream bottleneck**
2. **LCR benefit is zero**

Cost-benefit analysis for "SWC-3"

North Gila – Imperial Valley 500 kV line #2

Million US$

	2018	2019	2020	2021	2022	2023	2024	2025	20xx
Production benefit	21	21	21	20	20	20	20	20	…
Capacity benefit	-	-	-	-	-	-	-	-	…
Total yearly benefit	21	21	21	20	20	20	20	20	…

Assumed operation year ➔	2018
Total benefit Sum of discounted yearly benefits	279
Total cost Total revenue requirement	428

295	Total capital cost

Net benefit	(149)
Benefit-cost ratio	0.65

Table of Contents

Preliminary results summary

Evaluation of economic benefits to the ISO ratepayers

Proposed upgrades			Economic assessment			
ID	Transmission Facilities	Operation year	Benefit	Cost	BCR	Assessment
P26-3	Build Midway – Vincent 500 kV #4 (110 miles)	2023	$55M	$1,595M	0.03	Uneconomic
NWC-1	Increase PDCI capacity by 500 MW	2018	-$4M	$435M	-0.01	Uneconomic
SWC-1	Harry Allen – Eldorado 500 kV line (60 miles)	2023	$138M	$174M	0.79	TBD
SWC-2	Delaney – Colorado River 500 kV line (110 miles)	2020	$645M	$498M	1.30	Economic
SWC-3	North Gila – Imperial Valley 500 kV line #2 (80 miles)	2018	$279M	$428M	0.65	Uneconomic

For the Harry Allen – Eldorado 500 kV line, the benefit has not included capacity benefit yet
Study is underway to determine the capacity benefit

Note:
The US dollars are in year 2012 values
The benefits and costs are net present values at the proposed operation year
The “benefit” is the total economic benefit determined by the economic planning study
The “cost” is the total revenue requirement that includes impacts of capital costs, tax expenses, O&M costs, etc.

Open issues

Production benefits:

At this point, the following study assumptions are uncertain:
1. LA Basin/San Diego local requirement impacted by SONGS and OTC
2. Reliability-driven upgrades identified in this 2013/2014 planning cycle
3. Policy-driven upgrades identified in this 2013/2014 planning cycle

It is unlikely that the above factors will negatively impact the calculated benefits
Thus, there is no plan to further revise the current production simulation model

Capacity benefits:

Power flow study is underway to quantify incremental RA capacity increase MW for the Harry Allen – Eldorado 500 kV line

Study is underway to quantify the capacity benefit for the Harry Allen line

Thanks!

Your questions and comments are welcome

For clarifying questions, please contact Xiaobo Wang at:
(916)608-1264, XBWang@caiso.com

For written comments, please send to:
RegionalTransmission@caiso.com

Incremental Capacity assessment for Delaney-Colorado River 500 kV line project

2013/2014 Transmission Planning Process Stakeholder Meeting

Yi Zhang
Senior Regional Transmission Engineer
November 20-21, 2013

Study summary

- Started from the Commercial Interest Policy Driven base case
- Two scenarios were studied:
  - With the category 1 upgrades proposed in 2013/2014 planning cycle were modeled
    - Phase shifter on Imperial Valley – ROA 230 kV line
    - 150 MVAr SVC at Suncrest 230 kV bus
  - Without the Category 1 upgrades

Path 46

Transmission Lines	Metering Point
Adelanto - Marketplace 500 kV	Marketplace 500 kV
McCullough - Victorville 500 kV # 1	McCullough 500 kV
McCullough - Victorville 500 kV # 2	McCullough 500 kV
Mead - Victorville 287 kV	Mead 287 kV
Eldorado - Lugo 500 kV	Eldorado 500 kV
Eldorado - Cima - Pisgah 230 kV # 1	Eldorado 230 kV
Eldorado - Cima - Pisgah 230 kV # 2	Eldorado 230 kV
Lugo - Mohave 500 kV	Mohave 500 kV
Julian Hinds - Mirage 230 kV	Mirage 230 kV
Colorado River – Delaney 500 kV #1	Colorado River 500 kV
Colorado River – Delaney 500 kV #2	Colorado River 500 kV
Mirage - Ramon 230 kV	Mirage 230 kV
Coachella - MIrage 230 kV	Mirage 230 kV
El Centro - Imperial Valley 230 kV	Imperial Valley 230 kV
Imperial Valley - North Gila 500 kV	North Gila 500 kV

Assessment of incremental capacity of Delaney – Colorado River 500 kV line (With Category 1 upgrades)

D – CR line	WOR	SCIT	Limiting components	Critical contingency
No	10772	16246	Suncrest – Sycamore 230 kV lines; Suncrest 230 kV and 500 kV buses voltage dip	Imperial Valley – Eco 500 kV N-1 with SPS of tripping generation
Yes	11179	16659	Suncrest – Sycamore 230 kV lines; Suncrest 230 kV and 500 kV buses voltage dip;	Imperial Valley – Eco 500 kV N-1 with SPS of generation tripping
			Mead – Marketplace 500 kV line	RedBluff – Devers 500 kV lines N-2 with SPS of tripping generation

- About 400 MW incremental capacity on WOR

Assessment of incremental capacity of Delaney – Colorado River 500 kV line (Without Category 1 upgrades)

D – CR line	WOR	SCIT	Limiting components	Critical contingency
No	9747	15260	TJI-230 – OtayMesa 230 kV line	Imperial Valley – Eco 500 kV N-1 with SPS of tripping generation
Yes	10006	15513	TJI-230 – OtayMesa 230 kV line	Imperial Valley – Eco 500 kV N-1 with SPS of generation tripping

- About 260 MW incremental capacity on WOR

Summary

- 2023 peak load condition with modeling 33% RPS base portfolio has been studied
- Proposed Delaney – Colorado River 500 kV line increases WOR transmission capacity in the peak load condition
- The Category 1 upgrades identified in 2013/2014 planning cycle allows more incremental capacity on WOR
  - Without Category 1 upgrades, D-C 500 kV line increases WOR capacity by about 260 MW
  - With Category 1 upgrades, D-C 500 kV line increases WOR capacity by about 400 MW

Wrap-Up

2013/2014 Transmission Planning Process Stakeholder Meeting

Tom Cuccia
Sr. Stakeholder Engagement and Policy Specialist
November 20-21, 2013

Next Steps

Date	Milestone
November 21, 2013	Stakeholder Meeting Day 2 – Recommendations for Management Approval of Reliability Projects less than $50 Million & Long-Term CRR Simultaneous Feasibility Test
November 21 – December 5	Stakeholder comments to be submitted to regionaltransmission@caiso.com
January 31, 2013	2013/2014 Draft Transmission Plan posted
February 2013	Stakeholder Meeting on contents of draft Transmission Plan