Economic Planning-
Production cost model development

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2017-2018 Transmission Planning Process Stakeholder Meeting
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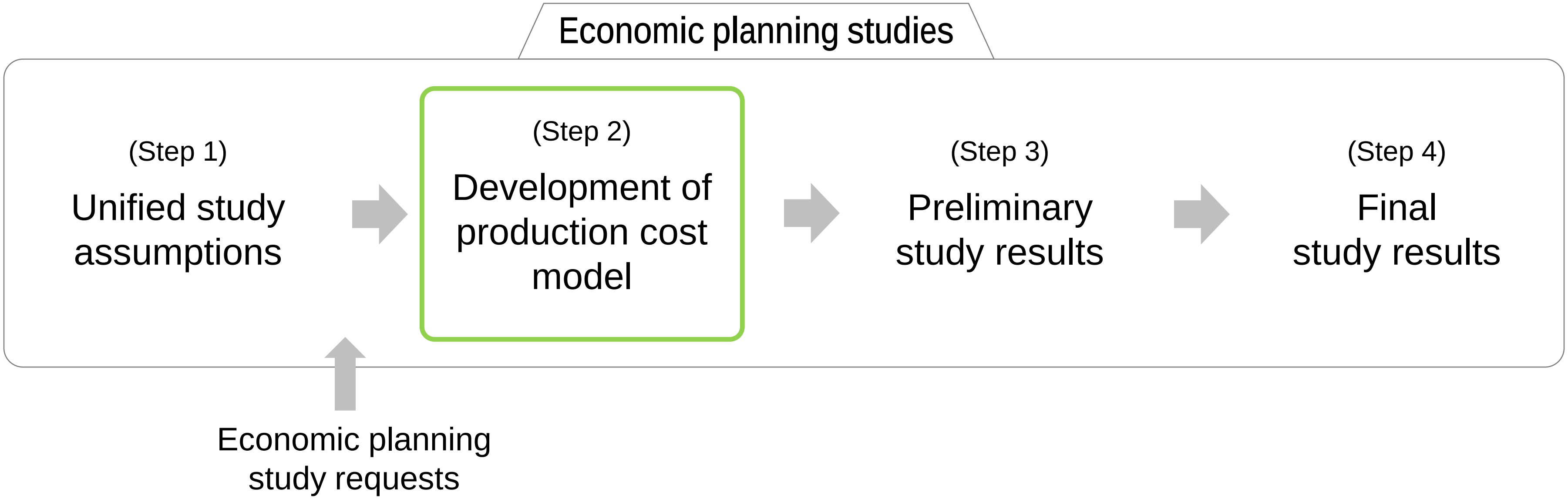
Steps of economic planning studies



Multi-processes of production cost model (PCM) development in 2017-2018 cycle

- ISO's PCM development
  - Started from ISO's 2016-2017 PCM, which was based on WECC 2026 Common Case (CC) v1.3 and v1.5
- The following will be incorporated:
  - PCM for ITP studies
    - Based on ISO's 2016-2017 PCM, but incorporated recommendations from other planning regions
  - Anchor dataset (ADS) PCM case
    - Started from WECC 2026 CCv1.7
  - WECC 2026 CC v2.0 posted in September 2017

ISO's major updates in this planning cycle

- WPR (NTTG, Columbia Grid, and WestConnect) recommended updated in the corresponding areas
- Latest CEC load forecast for all CAISO areas,
  - BTM and AAEE are modeled as hourly resources
- Transmission topology consistent with ISO's unified planning assumption
- Transmission constraints identified in reliability and LCR assessments
- Generator models consistent with ISO's unified planning assumption including renewable development and generator retirement/replacement
- Grid and market operation models and requirements

Next steps

- Continue on database development, mainly:
  - Update transmission constraints based on the latest reliability study results
  - Coordinate with WPR and WECC on the modeling issues in ADS PCM seed case and TEPPC Common Case identified by planning regions and WECC
- Conduct production cost simulations and congestion analysis
- Provide update in the next TPP Stakeholder Meeting

Interregional Transmission Project (ITP) Evaluation and 50% RPS Out-of-State Portfolio Assessment

An information-only study performed as a continuation of 2016-2017 Transmission Planning Process

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Agenda

Context and drivers behind the assessment

1. Executive Summary
2. Methodology to assess the impact of OOS portfolio and effectiveness of ITPs
3. Assumptions –
   i. Resource assumptions and modeling
   ii. Topology assumptions and modeling
4. Study scenarios
5. Key findings
   i. Power flow assessment
   ii. Production cost simulation assessment
   iii. ATC assessment
6. Recommendations and next steps

Context

Continuation of the information-only 50% RPS special study (2016-2017 TPP)

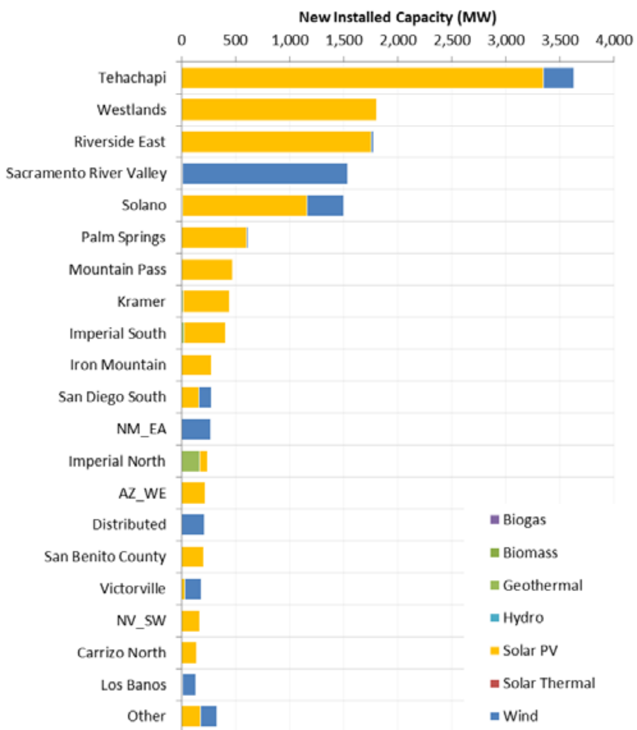
The 2016-2017 50% RPS study focused on

- Investigating the transmission impacts of moving beyond 33 percent RPS requirements in California;
- Testing the transmission capability estimates used in RPS calculator v6.2 and where appropriate, updating these transmission capability estimates; and
- Investigating transmission implications on in-state facilities of meeting part of California's 50 percent RPS requirement by assuming California's procurement of 2000 MW of wind resources in Wyoming and 2000 MW of wind resources in New Mexico.

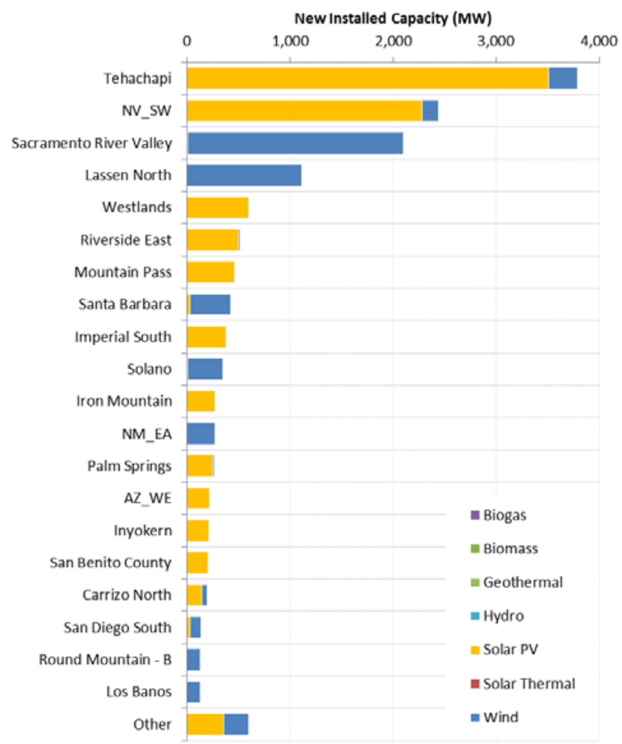
Portfolios provided by the CPUC; the Out-of-state portfolio shows a shift to higher WY and NM wind

Portfolio	In-state FCDS	In-state EODS	OOS EODS/FCDS
MW Capacity	14,842	14,814	11,093

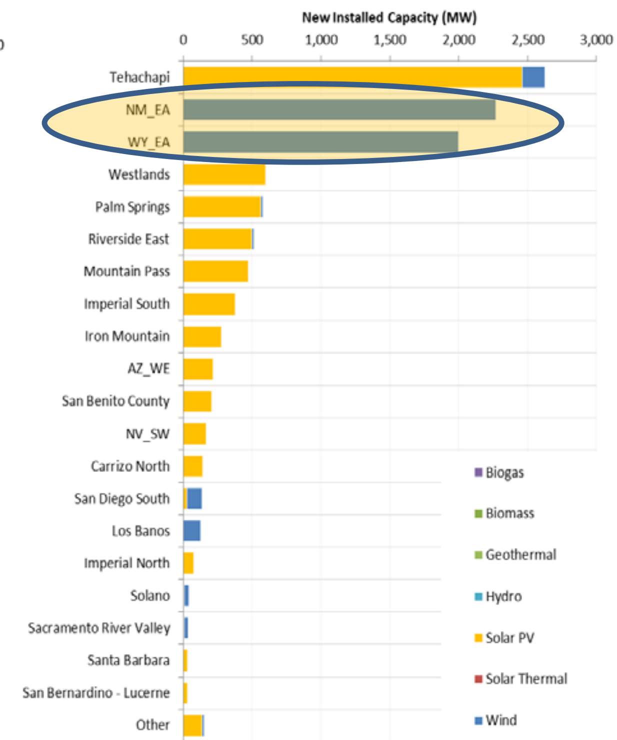
In-state FCDS



In-state EODS



Out-of-state FCDS/EODS



Note - RPS calculator v6.2 was used to generate the portfolios

Findings from 2016-2017 out-of-state portfolio assessment helped us identify three action items

Assessment	Key findings pertaining to OOS portfolio (2016-2017 50% special study)
Production Cost Simulation	• Curtailment: OOS portfolio showed the lowest curtailment • Transmission congestion: OOS portfolio showed the least amount of intra-CA congestion • <u>Further coordination is expected on stressed scenario identification and reviewing study results</u>
Reliability Assessment	• OOS portfolio was the least severe one • No major issues in the Northern CA system due to lower amount of resource selection • One potential issue in Southern CA observed in all portfolios • <u>The snapshots identified with CA transmission in mind were not the most stressed ones for the system outside of CA</u>
Deliverability	• Evaluated the need for MIC expansion and found that adequate import capacity exists to deliver OOS resources (NM and WY) from injection point into CAISO BA to CAISO loads

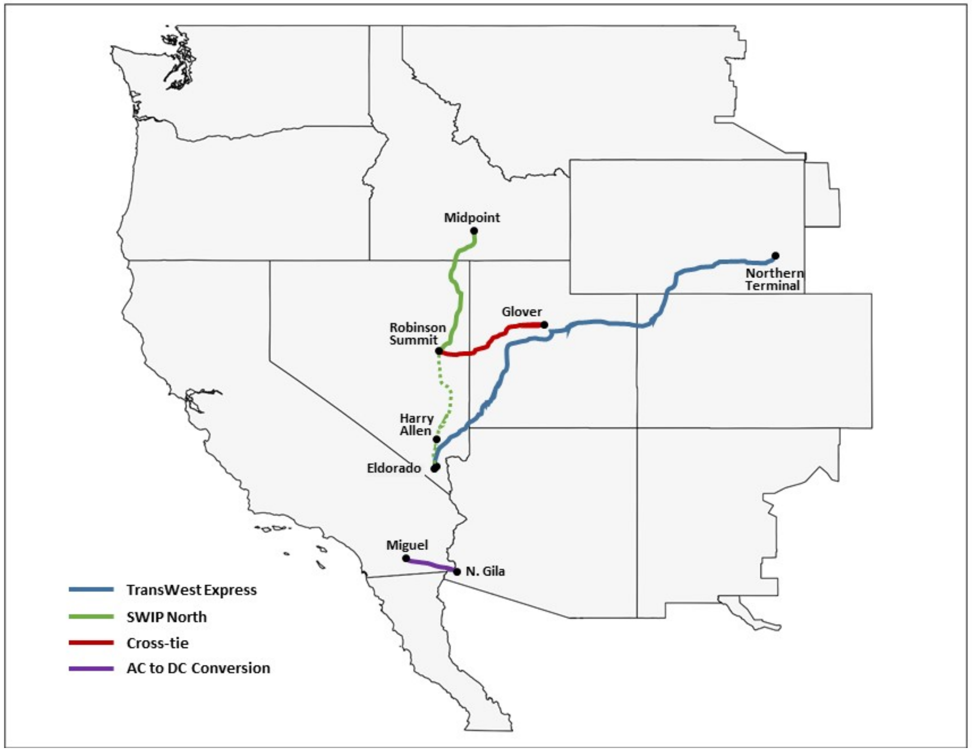
Three action items identified based on ISO's analysis and stakeholder feedback –

1. Refining the assumptions and models
2. Using the out-of-state portfolio to test ITP evaluation framework in preparation for the next planning cycles; and
3. Exploring a way to capture the Available Transmission Capacity (ATC) for out-of-state RPS resources

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

- TransWest Express (TWE)
  - *California ISO*
  - *NTTG*
  - *WestConnect*
- SWIP North (SWIP-N)
  - California ISO
  - *NTTG*
  - *WestConnect*
- Cross-tie Transmission Line
  - California ISO
  - *NTTG*
  - *WestConnect*
- Renewable Energy Express HVDC Conversion (REX HVDC Project)*
  - *California ISO*
  - *WestConnect*

Relevant Planning Region



A common theme among all projects is the focus on providing California transmission access to out-of-state renewable generation in Wyoming and New Mexico to support California's 50 percent RPS goal.

** This project was previously named Desert Tortoise Expressway.*

Regional coordination efforts resulted in model refinement and contingency list creation

- Received input from WestConnect and NTTG about the location and size of wind resources in NM and WY respectively
- WPRs provided input regarding transmission topology enhancements in alignment with the ongoing WECC Anchor Data Set work
- Shared power flow models with WPRs and received feedback
- Shared contingency files with ColumbiaGrid, WestConnect and NTTG; the WPRs provided crucial information regarding additional contingencies to be tested
- APS and NV Energy provided specific input regarding contingencies to be tested

Objectives

Test the system outside of CA using OOS portfolio and leverage the findings to gain insights about ITPs

- Refine the out-of-state resource and topology modeling
- Identify Available Transfer Capability that can be used by the wind resources in WY and NM in order to deliver to CA
- Identify transmission constraints outside of CA while trying to meet part of the 50% RPS obligation by relying on wind resources in WY and NM
- Test effectiveness of ITPs in mitigating observed transmission issues outside of CA and test a framework for comparing ITPs

Executive Summary

Summary of directional insights about ITPs

Total ISO renewables including WY and NM wind

Impact on only WY and NM wind curtailment

	SWIP-N with Gateway West*	Cross-Tie with Gateway South*	TransWest Express	REX HVDC with SunZia
ISO renewable curtailment **	—	—	—	—
WY wind curtailment **	↓↓↓	↓↓	↓	—
NM wind curtailment **	—	—	—	↓↓
Curtailment (No ISO Export Limit)	—	—	—	—
Thermal Overload Performance	↓↓	↓↓	↓↓	—
Planning Level Cost***	$2B - $3.9B	$1.5B - $2.1B	$2.4B – 3.2B	$1.9B - $4.6B

↓ Reduction in curtailment or overload

— No impact relative to baseline

** SWIP-N and Cross-Tie without certain segments of Gateway were studied and were found to be decisively inadequate for the purpose of delivering Wyoming resources to California*

*** Curtailment under 2,0000 MW Net ISO Export Limit*

**** Based on (i) the request window submittals and (ii) cost information specified in RETI 2.0 Western Outreach Project Report – (http://docketpublic.energy.ca.gov/PublicDocuments/15-RETI-02/TN214339_20161102T083330_RETI_20_Western_Outreach_Project_Report.pdf)*

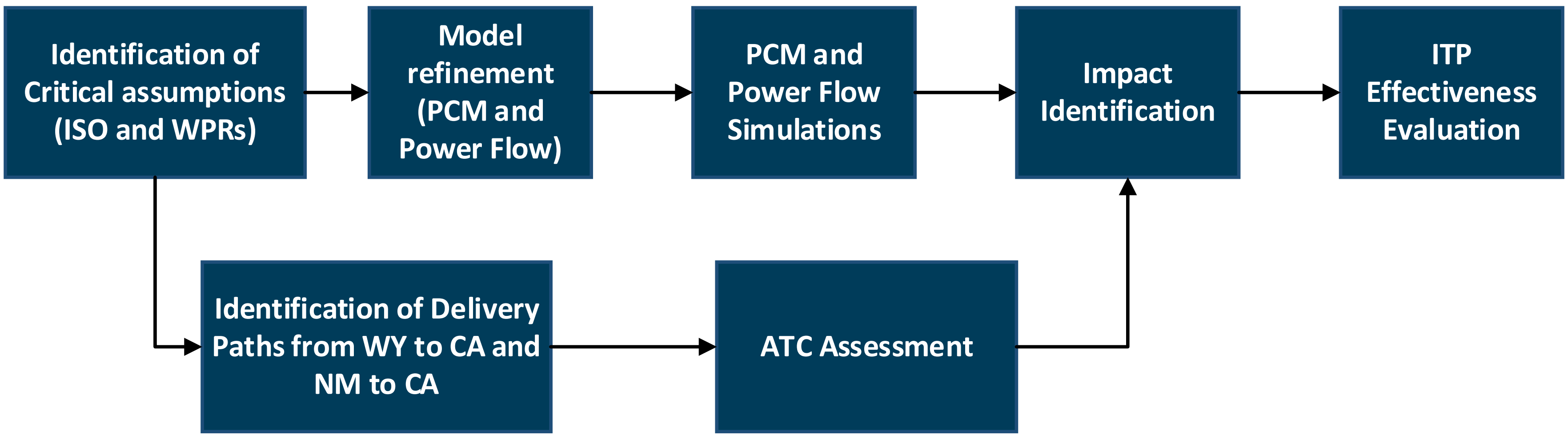
ATC Assessment

- The ISO’s examination of yearly, firm, point-to-point ATC data from the Western OASIS points to a severe lack of scheduling capability to deliver Wyoming and New Mexico wind to California
- None of the ITPs except TWE will create sufficient long-term, firm ATC from the renewable resource area all the way to the ISO without relying on other transmission not owned by the project sponsor. Note the proponent of the SWIP North project cites having pre-existing arrangements to secure transmission rights on the One Nevada Transmission Line (ON Line), addressing one of two transmission paths needing ATC on other transmission.

Methodology and Assumptions

Study methodology and sequence

The base cases used in the 2016-2017 50% RPS study were used as the starting point for developing base cases for this assessment. Where appropriate, the models were refined to incorporate the latest information received from the WPRs.



The ATC assessment was performed to determine the availability, if any, of existing transmission to import wind resources from Wyoming and New Mexico into California (OATI's Western OASIS was relied upon for this purpose)

Primary data sources for modeling refinements

- Models used by the ISO in 2016-2017 50% RPS study
- Information currently being prepared by the WPRs for the development of WECC's Anchor Data Set
- NTTG's biennial study plan version 3.5[1] (draft as on May 29, 2017)
- WestConnect's regional study plan for 2016-2017 planning cycle[2]

1 https://www.nttg.biz/site/index.php?option=com_docman&view=document&layout=default&alias=2825-2016-17-nttg-biennial-study-plan-quarter-6-revisions-redlined-05-08-2017&category_slug=planning-committee-meeting-material-05-10-2017&Itemid=31

2 https://doc.westconnect.com/Documents.aspx?NID=17180

Uncertainties about key assumptions with potential impact on the ITP assessment

Gateway Energy Project

PacifiCorp IRP resource (~1,100 MW of additional wind in WY)

Assumptions regarding Gateway Energy Project and incremental Wyoming wind specified in PAC IRP were expected to be critical for Wyoming wind scenario

SunZia project

Assumptions regarding SunZia Project were expected to be critical for New Mexico wind scenario

Key modeling enhancements and topology/resource assumptions

Starting study model: 2016-2017 TPP 50% RPS out-of-state portfolio case

- Resource Assumptions
  - In-state RPS resources
  - Out-of-state RPS resources
  - All other resources
- Topology Assumptions
  - Planned transmission within ISO
  - Planned transmission outside of ISO

- No change to in-state RPS
- WY and NM RPS resources identified in the out-of-state portfolio
- Additional wind resources identified in WY as part of PacifiCorp's IRP (~1,100 MW)
- Minor generation adjustments per the latest WPR ADS seed case (as of May 2017)

- Modeled projects approved in the 2016-2017 TPP
- Relied on the information received from the Anchor Data Set work being performed by WPRs
- Gateway Energy Project
- SunZia Project

Baseline assumptions

	Resource Assumptions	Transmission Assumptions
Case A	CPUC's out-of-state 50% portfolios - ~2,000 MW in Wyoming - ~2,000 MW in New Mexico	Only the committed segments of Gateway Energy Project
Case B	CPUC's out-of-state 50% portfolios - ~2,000 MW in Wyoming - ~2,000 MW in New Mexico + ~1,100 MW incremental wind in Wyoming as included in PacifiCorp's 2017 IRP	Committed segments of Gateway Energy Project + Aeolus – Anticline 500 kV line*

* PacifiCorp has requested the "acknowledgment" of the Aeolus to Bridger/Anticline transmission segment in its 2017 IRP - https://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2017_IRP/2017_IRP_VolumeI_IRP_Final.pdf

Due to interdependencies with other major transmission projects and resource assumptions several scenarios were studied

	TWE	Cross-Tie	Cross-Tie with Gateway South	SWIP-N	SWIP-N with Gateway West	REX HVDC	REX HVDC With SunZia
Case A	✓	✓	✓	✓	✓	✓	✓
Case B	✓	✓	✓	✓	✓	✗	✗

- For SWIP-N and Cross-tie it was quickly evident that studying these projects without certain segments of Gateway was not going to add much value to PCM and power flow assessment
- AC-DC Conversion Project was not studied with baseline B because baseline B was specific to the WY wind scenario

Study Components

ITP-out-of-state 50% portfolio assessment

PCM simulations

The expected outcome of PCM simulations was:

- Extent of curtailment of out-of-state renewables
- Identification of transmission constraints outside of California that may results in significant amount of congestion when delivering wind resources from WY and NM to CAISO BAA
- Stressed snapshot identification for the purpose of power flow studies
- Impact of ITPs on PCM results

Power flow and stability studies

- Power flow studies were performed in order to (i) identify additional transmission limitations that may not be captured by PCM studies and (ii) to confirm the transmission system limitations identified by PCM simulation and (iii) capture the impact of ITPs
- The 8,760 hours of snapshots created during PCM simulations were used to identify high transmission system usage patterns to be tested using the power flow models for reliability assessment.
- Contingency assessment was performed with a focus on the system outside of California.

ATC assessment

- The ISO tested if adequate ATC exists for delivering the renewable resources from Wyoming and New Mexico to the ISO BAA.
- At a conceptual level, this exercise can also be viewed as a loose proxy for testing 'deliverability' of these out-of-state resources.
- However, the ISO believes that it is reasonable to assume that large out-of-state resource installations to be serving California load would not be viable without long-term firm transmission service from the point of receipt to the CAISO BAA boundary.

Power Flow Assessment

Power flow snapshots were selected based on stressed conditions from an out-of-state system perspective

GridView Simulations

8760 Hours of production cost simulation results

Subset of hours with stressed major path flows (WY to CA; NM to CA)

Prior study experience and engineering judgement

Within this subset, selected hours with the maximum renewable potential in WY and NM (dispatch + curtailment)

Special considerations e.g. P19 for WY wind vs. P22 for NM wind

Wyoming Assessment snapshot	New Mexico Assessment snapshot
March 14 Hour 16	**April 07 Hour 17**

Key findings for the WY snapshot

- N-0:
  - 230 kV system in Southwestern WY was heavily constrained with and without ITPs
  - In case B, we had to add more than 1,000 MVAR to dispatch ~3,000 MW of wind in Wyoming
- N-1:
  - Contingencies of 230 kV elements result in case divergences indicating a need for a gen-drop scheme or additional reactive support
  - [Local issues could be mitigated by transmission upgrades]
  - Contingencies on P19 and West of Borah
- P19 (Bridger West) was allowed to exceed its existing path rating in Case B in order to expose downstream bulk system issues
- Thermal relief index was computed to account for a holistic overload relief provided by each ITP as well as adverse impacts

What is the representative thermal relief index (TRI)?

- The ISO devised simple a way to capture the resultant system-wide thermal loading relief performance of each ITP
- Major emphasis of power flow comparison is on thermal loading performance because voltage issues can generally be mitigated by local mitigations without requiring area-wide infrastructure build-out
- TRI takes into account
  - Impact on base case (N-0) loadings above 90% of normal rating
  - Impact on (N-1) loadings above 90% of emergency rating
  - Impact on credible (N-2) loadings above 90% of emergency rating

$$TRI = \sum_{n=0}^{2} Wn * [(\#\ of\ loading\ reductions)_n - (\#\ of\ loading\ increases)_n]$$

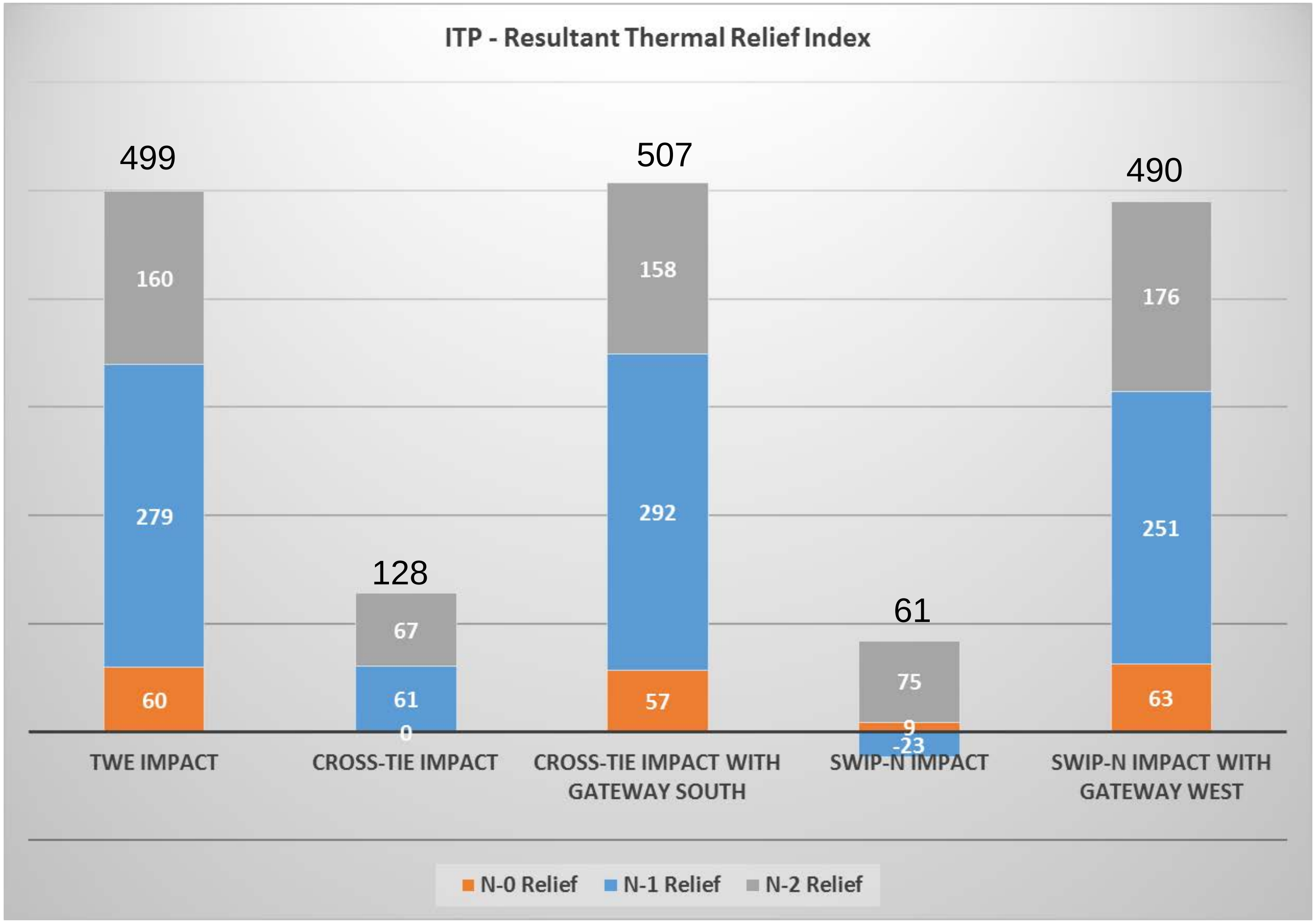
Where,

n = Contingency condition e.g. N-0, N-1, N-2, etc.
W_n = Weightage for the corresponding contingency condition

[The weightage W_n captures the relative importance of providing relief under N-0, N-1 and N-2 conditions. E.g. relief provided under n-0 issues was assigned the highest weightage ($W_0=3$) followed by relief for n-1 ($W_1=2$) and then n-2 ($W_2=1$)]

- In this assessment, all the ITPs demonstrated the same relative performance across all three components

TRI comparison for ITPs delivering WY wind to CA



Power flow results for NM snapshot and REX HVDC project

- N-0: No issues in baseline case; two overloads observed after modeling AC-DC Conversion Project

Monitored Facility	Contingency Name	% Overload	
		Baseline A	Baseline A + REX HVDC
22430 SILVERGT 230 22771 BAY BLVD 230 1 1	Base Case	80	104
22710 SANLUSRY SC 230 22504 MISSION 230 1 1	Base Case	74	128

- N-1: No impact on overloads observed in New Mexico locations very close to the wind resources; one additional overload observed on IV – El Centro 230 kV line after modeling AC-DC Conversion Project

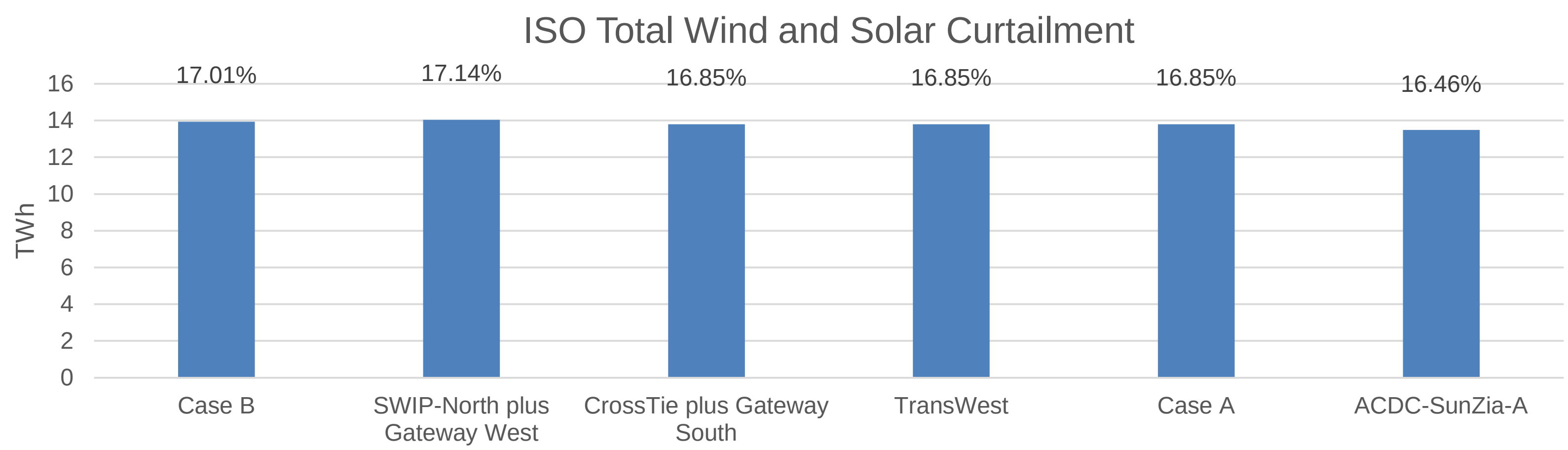
Monitored Facility	Contingency Name	% Overload	
		Baseline A	Baseline A + REX HVDC
10390 RIOPUERC 345 10025 B-A 345 2 1	line_5_Line B-A 345.0 to RIOPUERC 345.0 Ckt 1	113	113
21025 ELCENTSW 230 22356 IMPRLVLY 230 1 1	line_287_Line IMPRLVLY 500.0 to OCOTILLO 500.0 Ckt 1	-	108

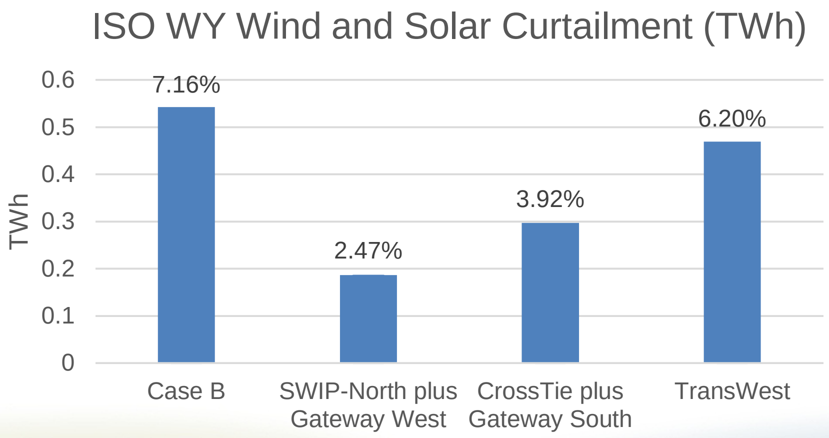
Production Cost Simulation Assessment

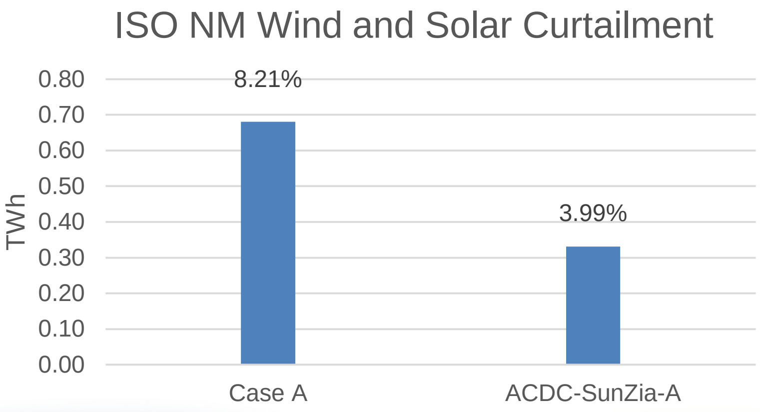
Overview of Production Cost Model for ITP studies

- Started from the PCM for OOS 50% portfolio in 2016/17 planning cycle
- Updated ISO’s network model to reflect the changes identified in 2017/2018 planning cycle reliability assessment
- Updated WPR (NTTG, WestConnect, and ColumbiaGrid) system models based on recommendations of the corresponding planning regions
- Load forecast and NG/CO2 prices remained the same as in the last planning cycle
- WY local 230 kV line limits were not enforced

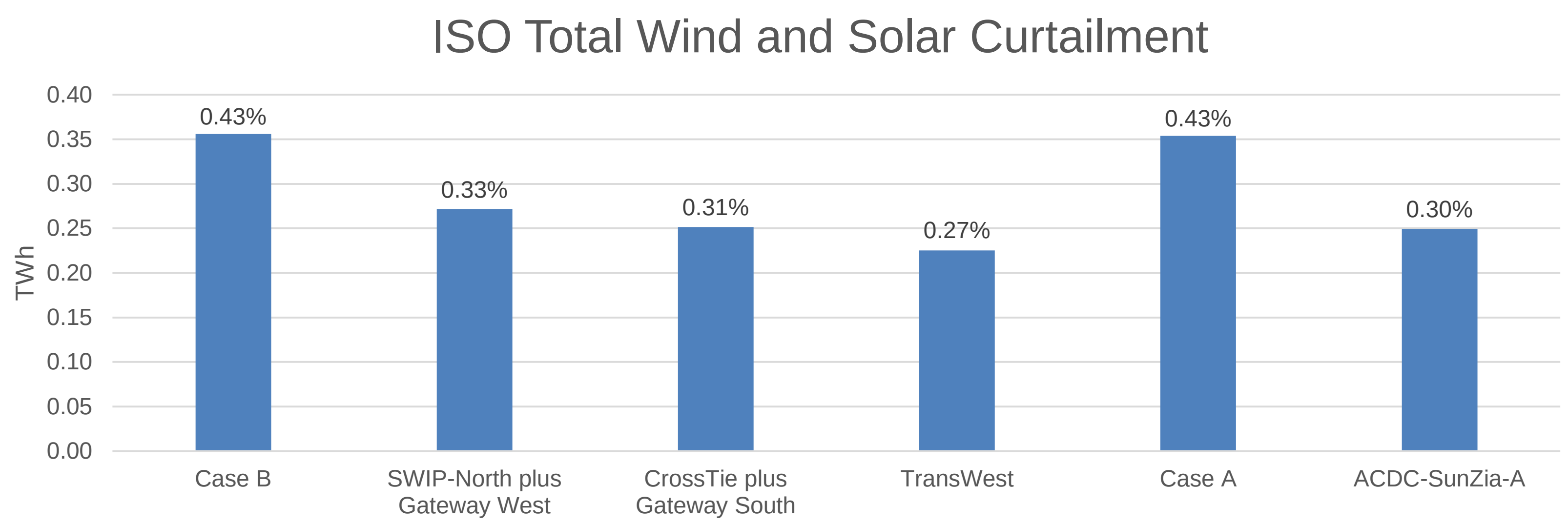
ISO Wind and Solar Curtailment – 2000 MW ISO Net Export Limit scenario







ISO Wind and Solar curtailment – No Export Limit scenario



WY and NM wind generation was not curtailed in the No Export Limit scenario

Major congestion related to OOS wind – Case A

Transmission congestion is also related to overall generation dispatch including Gas and Coal generation

2000 MW ISO Net Export limit	Case A		REX HVDC plus SunZia	
Constraints Name	**Costs T (K$)**	**Duration_T (Hrs)**	**Costs T (K$)**	**Duration_T (Hrs)**
P22 Southwest of Four Corners	6,038	477	41	6
P33 Bonanza West	5,086	583	4,692	521
P30 TOT 1A	4,877	539	3,252	427
FOURCORN 500/100 kV transformer #1	3,049	220	487	55
P29 Intermountain-Gonder 230 kV	2,071	562	1,512	507
BONANZA-MONA 345 kV line #1	1,609	223	1,131	163

No ISO Net Export limit	Case A		REX HVDC plus SunZia	
Constraints Name	**Costs T (K$)**	**Duration_T (Hrs)**	**Costs T (K$)**	**Duration_T (Hrs)**
P22 Southwest of Four Corners	2,599	238	0	0
P33 Bonanza West	280	62	129	55
P30 TOT 1A	768	139	350	71
FOURCORN 500/100 kV transformer #1	1,069	114	304	4
P29 Intermountain-Gonder 230 kV	175	22	9	11
BONANZA-MONA 345 kV line #1	0	0	0	0

Major congestion related to OOS wind – Case B

Transmission congestion is also related to overall generation dispatch including Gas and Coal generation

2000 MW ISO Net Export limit	Case B		SWIP North plus Gateway West		Cross Tie C3d plus Gateway South		TransWest	
Constraints Name	**Costs T (K$)**	**Duration_T (Hrs)**	**Costs T (K$)**	**Duration_T (Hrs)**	**Costs T (K$)**	**Duration_T (Hrs)**	**Costs T (K$)**	**Duration_T (Hrs)**
P19 Bridger West	175,209	3,295	28,975	977	53,574	1,786	85,161	4,406
P36 TOT 3	27,850	1,421	6,975	412	8,688	489	9,881	575
P66 COI	8,894	346	9,219	227	6,732	240	7,604	349
P80 Montana Southeast	8,334	587	1,974	153	3,376	270	3,745	297
P22 Southwest of Four Corners	5,181	432	2,091	190	2,675	239	4,166	402
P33 Bonanza West	1,874	238	1,581	196	846	106	858	140
P30 TOT 1A	2,842	256	2,921	278	2,711	269	2,827	255
P29 Intermountain-Gonder 230 kV	1,364	404	0	0	0	0	1,734	141
BONANZA-MONA 345 kV line #1	353	57	835	119	454	59	3,089	949

No ISO Net Export limit	Case B		SWIP North plus Gateway West		Cross Tie C3d plus Gateway South		TransWest	
Constraints Name	**Costs T (K$)**	**Duration_T (Hrs)**	**Costs T (K$)**	**Duration_T (Hrs)**	**Costs T (K$)**	**Duration_T (Hrs)**	**Costs T (K$)**	**Duration_T (Hrs)**
P19 Bridger West	116,022	2,579	15,425	708	51,366	1,923	59,656	2,756
P36 TOT 3	38,599	1,945	26,514	1,281	24,497	1,246	38,374	1,887
P66 COI	2,230	117	1,091	59	1,340	82	2,310	116
P80 Montana Southeast	1,703	153	416	41	530	44	1,175	124
P33 Bonanza West	57	16	82	20	22	6	21	4
P30 TOT 1A	227	35	511	64	646	70	503	53
P29 Intermountain-Gonder 230 kV	65	35	118	1	0	0	157	117
BONANZA-MONA 345 kV line #1	0	0	0	0	0	0	0	0

ATC Assessment

Stakeholders raised a question about the availability of ATC outside of California

Identified major transmission paths that establish a link from WY and NM to CA

⇩

Used the Common Western OASIS map to identify discrete scheduling points i.e. PODs (Points of Delivery) and PORs (Points of Receipt) of interest along these paths

⇩

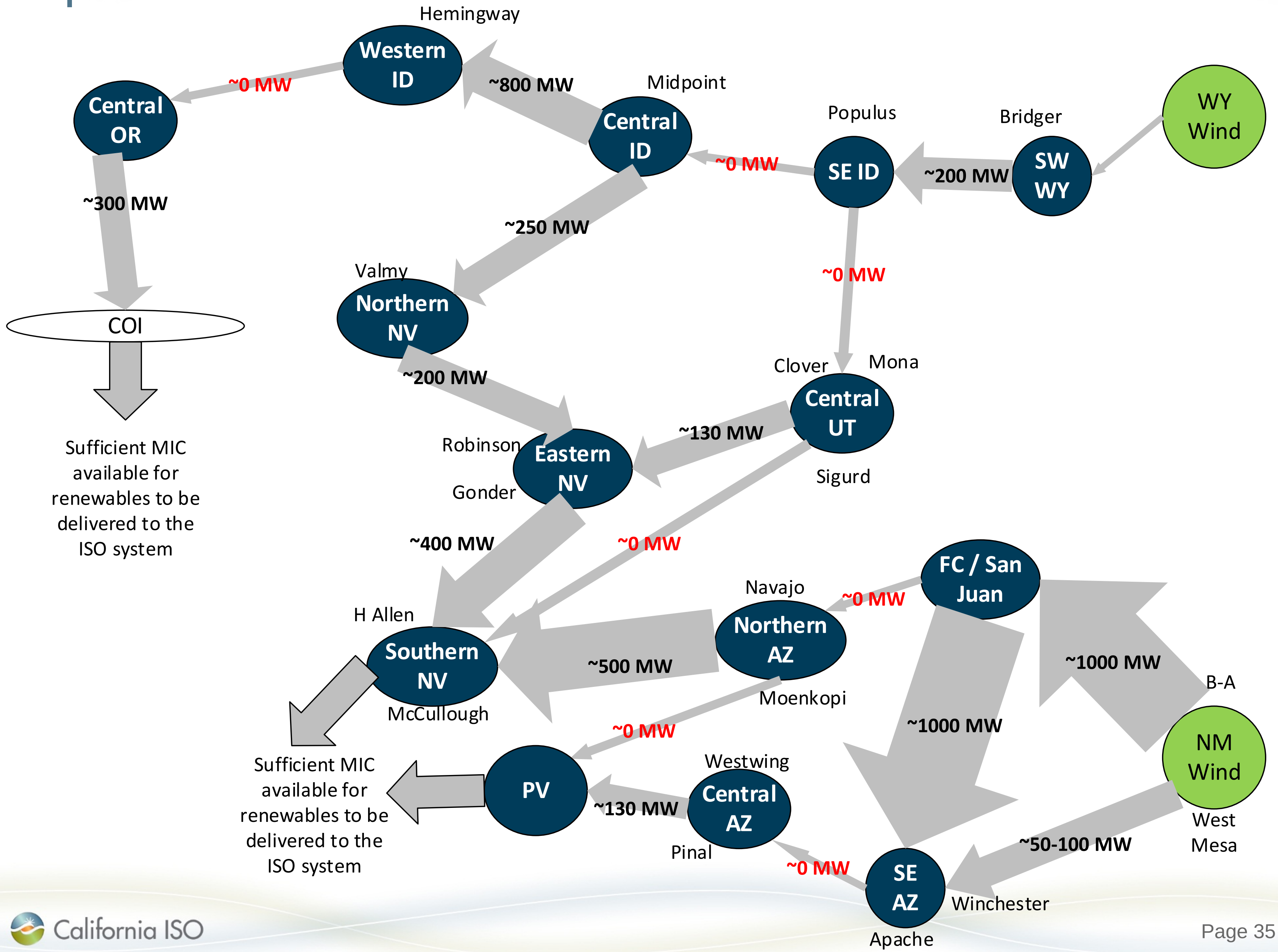
Utilized the Transmission Offering Summary from webSmartOASIS system to extract firm, point-to-point, yearly ATC entries submitted by corresponding TPs

⇩

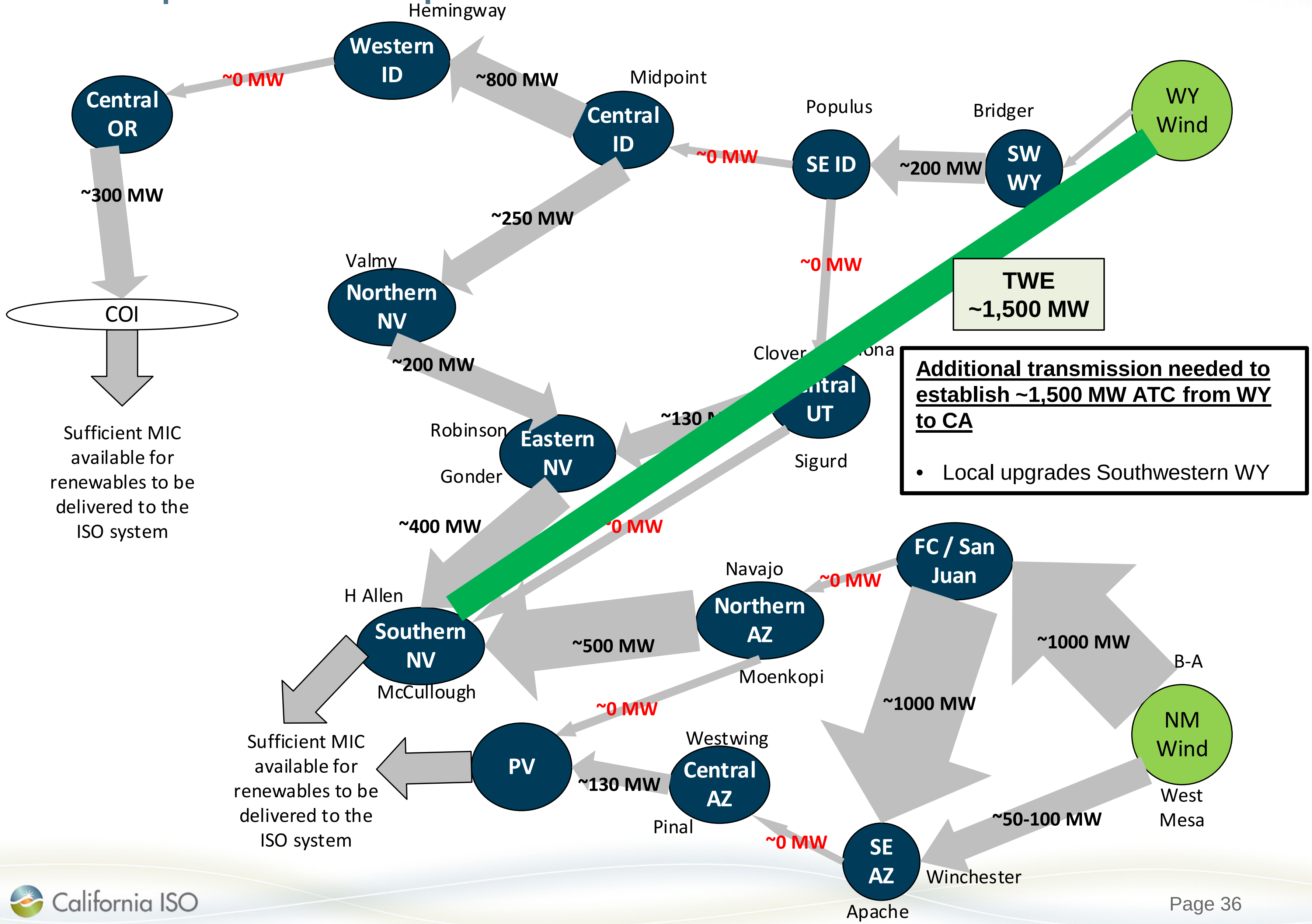
Pieced together the representative ATC numbers to gauge the long term availability of firm transmission along the path from WY and NM to CA

- OATI's webSmartOASIS system was utilized to extract ATC data
- Transmission Offering Summary in OASIS was utilized; this is what each Transmission Provider(TP) has submitted as available on a facility over a particular timeframe
- We looked for the active offerings in the first month of 2027 as a proxy for long-term availability

Representative ATC numbers



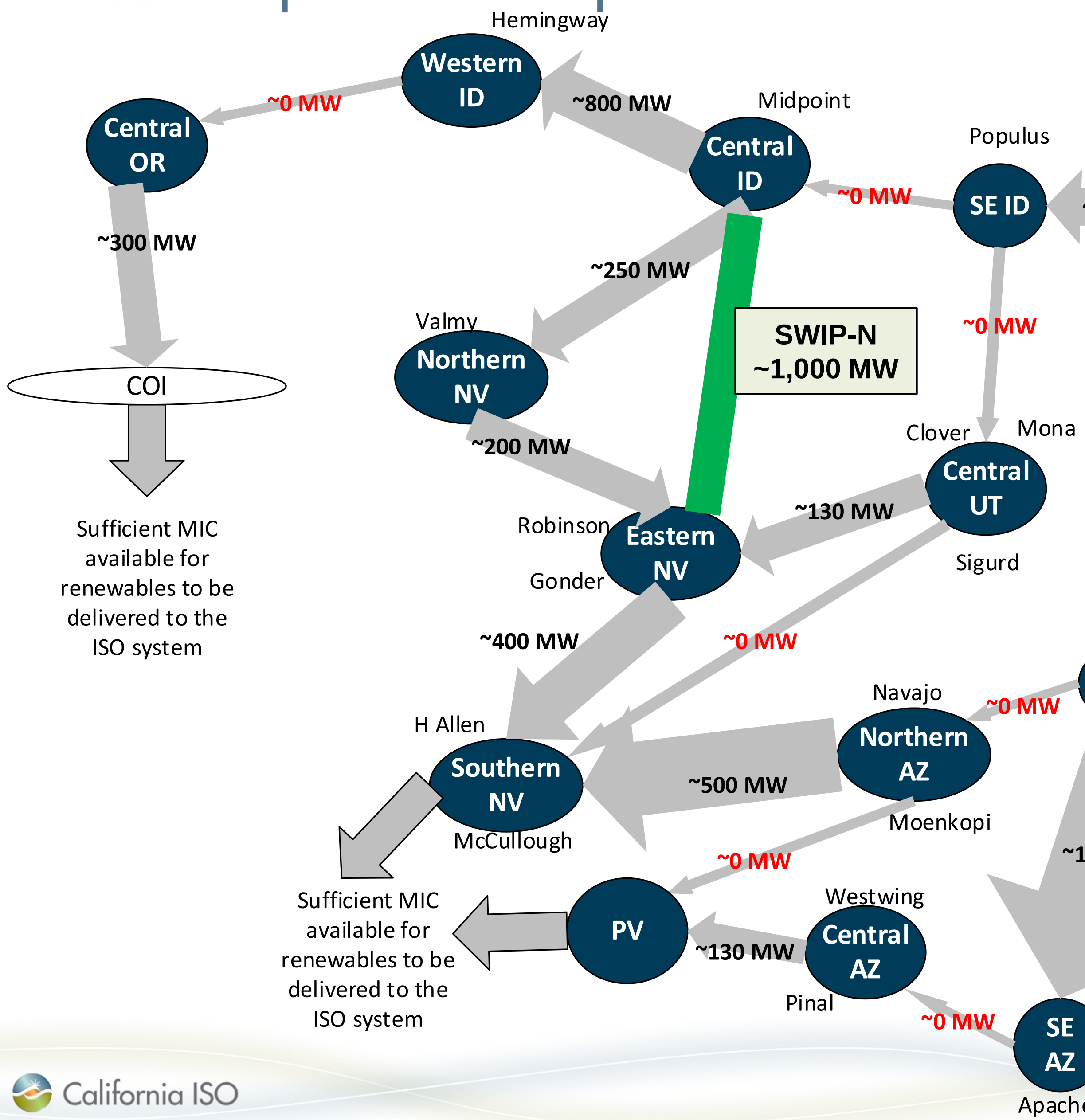
TWE's potential impact on ATC



<u>Additional transmission needed to establish ~1,500 MW ATC from WY to CA</u>

- Local upgrades Southwestern WY

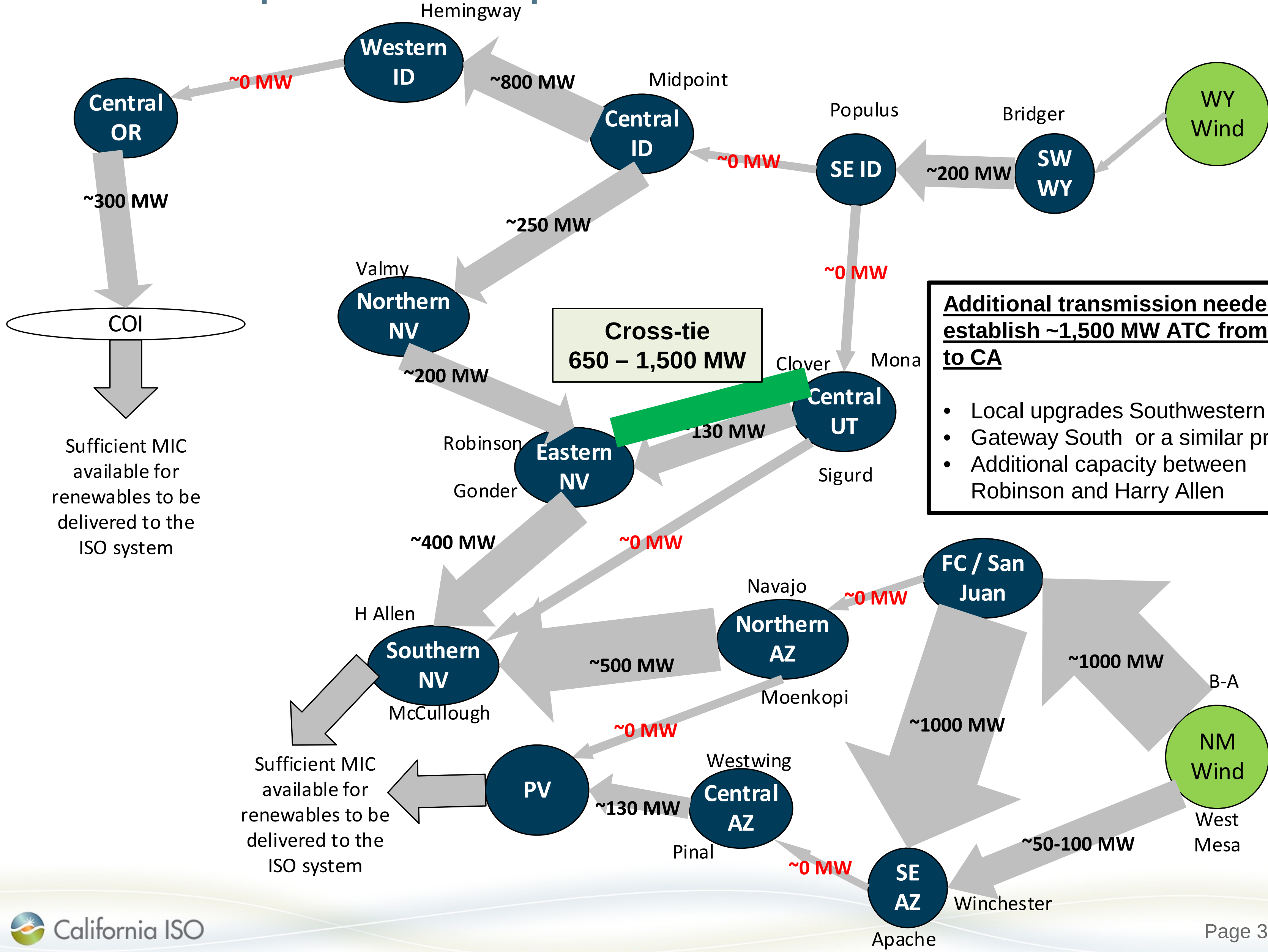
SWIP-N's potential impact on ATC



Additional transmission needed to establish ~1,500 MW ATC from WY to CA

- Local upgrades Southwestern WY
- Gateway West or a similar project
- Additional capacity between Robinson and Harry Allen

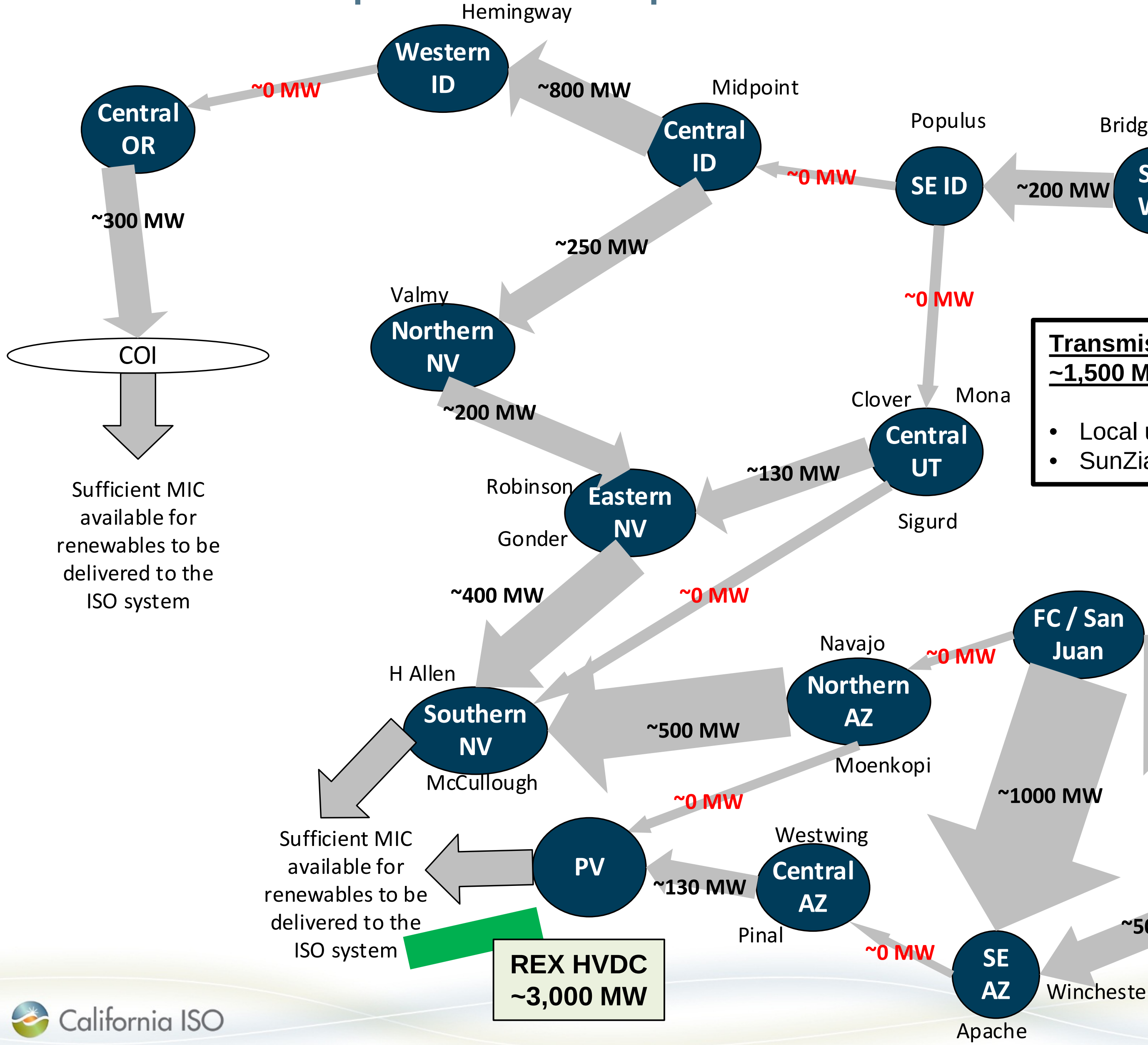
Cross-tie's potential impact on ATC



Additional transmission needed to establish ~1,500 MW ATC from WY to CA

- Local upgrades Southwestern WY
- Gateway South or a similar project
- Additional capacity between Robinson and Harry Allen

REX HVDC's potential impact on ATC



<u>Transmission needed to establish ~1,500 MW ATC from NM to CA</u>

- Local upgrades Western NM
- SunZia or a similar project

ATC assessment conclusion

- The schematic on the previous slide shows a severe lack of ATC to deliver Wyoming and New Mexico wind to California
- None of the ITPs except TWE will create sufficient long-term, firm ATC from the renewable resource area all the way to the ISO without relying on other transmission not owned by the project sponsor

Summary and Next Steps

Summary of Findings

PCM simulations

1. The ISO renewable curtailment did not show a noticeable reduction after adding any of the ITPs.
2. Relaxation of ISO Net Export Limit resulted in almost zero renewable curtailment. This indicates that the renewable curtailment under 2,000 MW ISO Net Export scenario is not primarily related to transmission congestion.
3. ITPs show a variation in transmission congestion performance. It is important to note that this congestion is driven by overall dispatch which includes non-renewable resource

Power flow studies

1. Power flow performance of TWE, SWIP-N (with Gateway West) and Cross-tie (with Gateway South) is comparable
2. SWIP-N and Cross-tie projects without the corresponding Gateway segments do not provide much thermal relief when delivering resources from WY to CA
3. REX HVDC project does not greatly impact power flow performance when delivering resources from NM to CA

ATC assessment

1. ATC assessment shows severe shortage of contractual capacity to deliver WY and NM resources to CA over the existing transmission system
2. TWE would provide ~1,500 MW of ATC from Southwestern WY to Southern CA
3. SWIP-N and Cross-tie would rely corresponding segments of Gateway project and some existing facilities to establish ~1,500 MW ATC between WY and CA
4. REX HVDC would not add ATC at the most constrained locations along the NM to CA path

Attributes requiring further consideration given the differing nature of the projects and dependencies:

- How the transmission would be procured – interregional project, regional project, or component of generation procurement?
- Arrangements with other non-ISO transmission owners for capacity, and for development of non-ISO transmission
- Costs and cost responsibilities
- Staging and sequencing of transmission and generation resources

Recommendations for next steps

- Utilize the results obtained from this study for future out-of-state RPS portfolio creation
- Create a framework for accounting for interdependencies of ITPs and other non-ITP infrastructure projects while evaluating ITPs
- Incorporate ATC assessment as part of the ITC evaluation framework for future ITP RW submittals
- Explore further the other attributes that would be taken into account in selecting a “preferred” project to access out of state wind resources

Thank you!

Bulk Energy Storage Resource Case Study

- Update to the 2016-2017 Transmission Plan Studies

Shucheng Liu
Principal, Market Development

2017-2018 Transmission Planning Process Stakeholder Meeting
September 21, 2017

Purpose of the ISO bulk energy storage case study

- To assess a bulk storage resource's ability to reduce
  - production cost
  - renewable curtailment
  - CO_2 emission
  - renewable overbuild to achieve the RPS target
- To analyze the economic feasibility of the bulk storage resource
- To consider the locational benefits of known potential bulk energy storage locations in ISO footprint

History of the bulk energy storage studies

- Initial study with 40% RPS was conducted in the 2015-2016 planning cycle[1] (in 2015-2016 Transmission Plan)
  - It was then updated with a 50% RPS portfolio and some other changes[2] (extension of the 2015-2016 cycle)
- Further study was conducted in the 2016-2017 transmission planning process with new assumptions and two sizes of bulk energy storages
  - Initial results were presented in the 2016-2017 process (February 28, 2017 stakeholder session and 2016-2017 Transmission Plan)
  - **The 2016-2017 study is re-capped and new sensitivity results are provided in this presentation**

[1] http://www.caiso.com/Documents/Board-Approved2015-2016TransmissionPlan.pdf
[2] http://www.caiso.com/Documents/BulkEnergyStorageResource-2015-2016SpecialStudyUpdatedfrom40to50Percent.pdf

Study Assumptions

Summary of assumptions for 2016-2017 studies

- This study was based on the Default Scenario of the CPUC 2016 LTPP/TPP Assumptions and Scenarios3
- It included major changes in the assumptions compared to the study with 50% RPS in 2015-2016 TPP
  - Retirement of non-dispatchable generation resources
  - Dispatchability of CHP resources
  - Lower load forecast and higher Additional Achievable Energy Efficiency (AAEE)
  - Lower RPS energy
  - Higher renewable curtailment prices

[3] Reference: http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M162/K005/162005377.PDF

Comparison of assumptions that may affect the results of this study notably

Assumption	This Study	2015-2016 TPP 50% RPS Study
Changes in non-dispatchable generation resources	Diablo Canyon nuclear plant (2,300 MW) is retired 2,786 MW CHP in operation	Diablo Canyon in operation 4,684 MW CHP in operation
Dispatchability of CHP resources*	50% of the 2,786 MW CHP is dispatchable	All 4,684 MW CHP is non-dispatchable
California Load forecast	64,009 MW 1-in-2 No AAEE non-coincident peak load 301,480 GWh energy	70,763 MW 1-in-2 No AAEE non-coincident peak load 322,218 GWh energy
California AAEE*	9,418 MW non-coincident peak impact 39,779 GWh energy CEC provided hourly profiles that usually have higher values in the late afternoon and early evening	5,713 MW non-coincident peak impact 24,535 GWh energy No hourly profile, offsetting load proportionally to the hourly load values

Comparison of assumptions that may affect the results of this study notably (cont.)

Assumption	This Study	2015-2016 TPP 50% RPS Study
CA RPS portfolio	36,776 MW installed capacity 110,288 GWh energy	40,986 MW installed capacity 125,307 GWh energy
Price of renewable generation curtailment*	-$15/MWh for the first 200 GWh, -$25/MWh for additional 12,400 GWh and -$300/MWh thereafter	-$300/MWh for all curtailment
Hydro condition	2005 hydro generation	2005 hydro generation
ISO maximum net export capability	2,000 MW	2,000 MW

Other assumptions

- Most of other assumptions for California are consistent with that in the study with 50% RPS in 2015-2016 TPP, including
  - Allowing renewable to provide load following-down up to 50% of the requirement
  - Enforcing a CAISO-wide frequency response requirement
- Assumptions for outside California are from the TEPPC 2026 Common Case v1.5 (October 21, 2016 release)

Additional sensitivity analyses were committed to address the uncertainties in some of the assumptions.

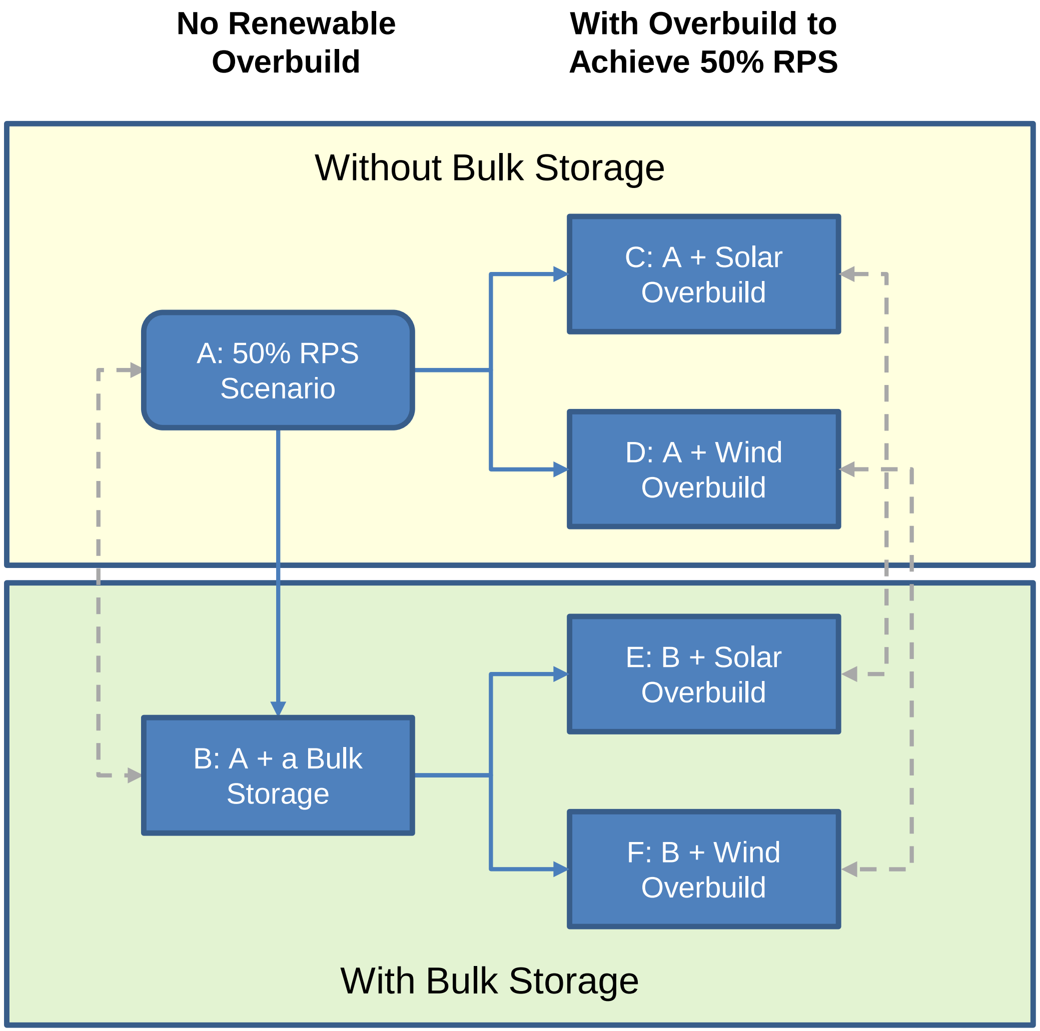
- In the 2016-2017 planning cycle, the ISO indicated that the ISO will conduct additional sensitivity analyses on at least the following assumptions:
  - Dispatchability of CHP resource
  - Level of AAEE
  - Prices of renewable curtailment

Study Approach

Study approach

- Analyzing two renewable build baselines, with and without a new bulk energy storage resource,
  - No overbuild of renewable resources
  - Overbuilding renewables to achieve 50% RPS target
- Overbuilding only solar or wind to explore the benefits of more diversified RPS portfolios
- Modeling two bulk energy storage sizes, 500 MW and 1,400 MW, separately

Definition of the study cases and expected takeaways



This study quantifies

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

It does not quantify

- transmission impact

Assumptions of the 500 MW new pumped storage resource, which represents the bulk energy storage

Item	Value
Number of units	**2**
Max pumping capacity per unit (MW)	**300**
Minimum pumping capacity per unit (MW)	75
Maximum generation capacity per unit (MW)	**250**
Minimum generation capacity per unit (MW)	5
Pumping ramp rate (MW/min)	**50**
Generation ramp rate (MW/min)	**250**
Round-trip efficiency	**83%**
VOM Cost ($/MWh, pumping and generation)	**1.5**
Maintenance rate	8.65%
Forced outage rate	6.10%
Upper reservoir maximum capacity (GWh)	8
Upper reservoir minimum capacity (GWh)	2
Interval to restore upper reservoir water level	Monthly
Pump technology	**Variable speed**
Reserves can provide in generation and pumping modes	**Regulation, spinning and load following**
Reserves can provide in off modes	**Non-spinning**
Location	Southern California

Assumptions of the 1,400 MW new pumped storage resource

Item	Value
Number of units	**4**
Max pumping capacity per unit (MW)	**422**
Minimum pumping capacity per unit (MW)	75
Maximum generation capacity per unit (MW)	**350**
Minimum generation capacity per unit (MW)	5
Pumping ramp rate (MW/min)	**50**
Generation ramp rate (MW/min)	**250**
Round-trip efficiency	**83%**
VOM Cost ($/MWh, pumping and generation)	**1.5**
Maintenance rate	8.65%
Forced outage rate	6.10%
Upper reservoir maximum capacity (GWh)	18.8
Upper reservoir minimum capacity (GWh)	2
Interval to restore upper reservoir water level	Monthly
Pump technology	**Variable speed**
Reserves can provide in generation and pumping modes	**Regulation, spinning and load following**
Reserves can provide in off modes	**Non-spinning**
Location	Southern California

Assumptions for revenue requirements and RA revenue calculation

Item	Generation & Transmission Costs (2016$/kW-year) [4]	NQC Peak Factor [5]	RA Revenue ($/kW-year) [6]
Large Solar In-State	242.19	47%	16.53
Large Solar Out-State	183.17	47%	16.53
Small Solar In-State	334.80	47%	16.53
Solar Thermal In-State	551.55	90%	31.66
Wind In-State	239.14	17%	5.98
Wind Out-State	223.88	45%	15.83
Pumped Storage In-State	407.91	100%	35.18

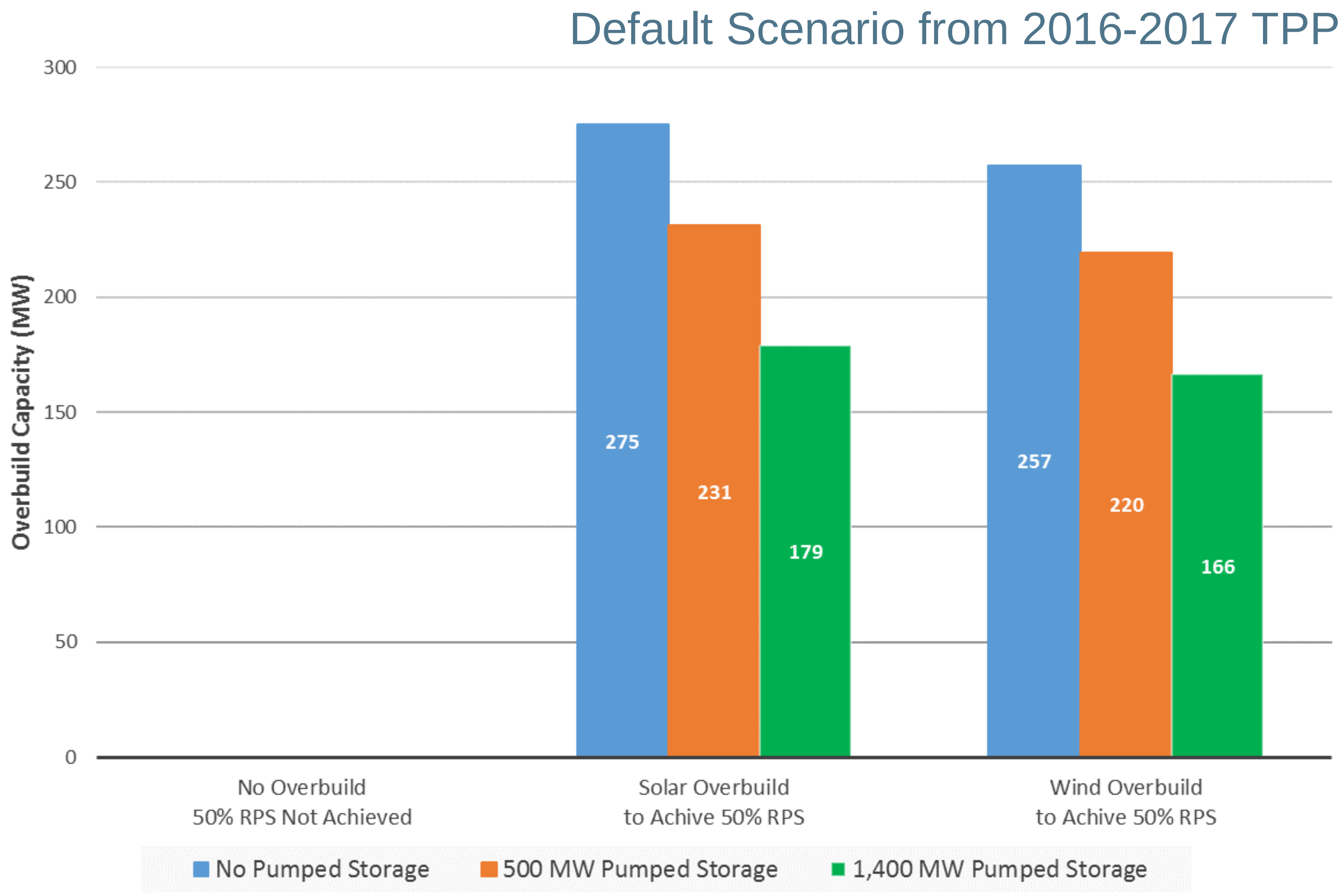
[4] Draft2017 IRP Assumptions http://www.cpuc.ca.gov/uploadedFiles/CPUC_Website/Content/Utilities_and_Industries/Energy/Energy_Programs/Electric_Power_Procurement_and_Generation/LTPP/DRAFT_RESOLVE_Inputs_2016-12-21.xlsx
[5] https://www.caiso.com/Documents/2012TACAreaSolar-WindFactors.xls and https://www.wecc.biz/Reliability/2024-Common-Case.zip
[6] CPUC 2015 RA Report http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442452221

Definition of the study cases

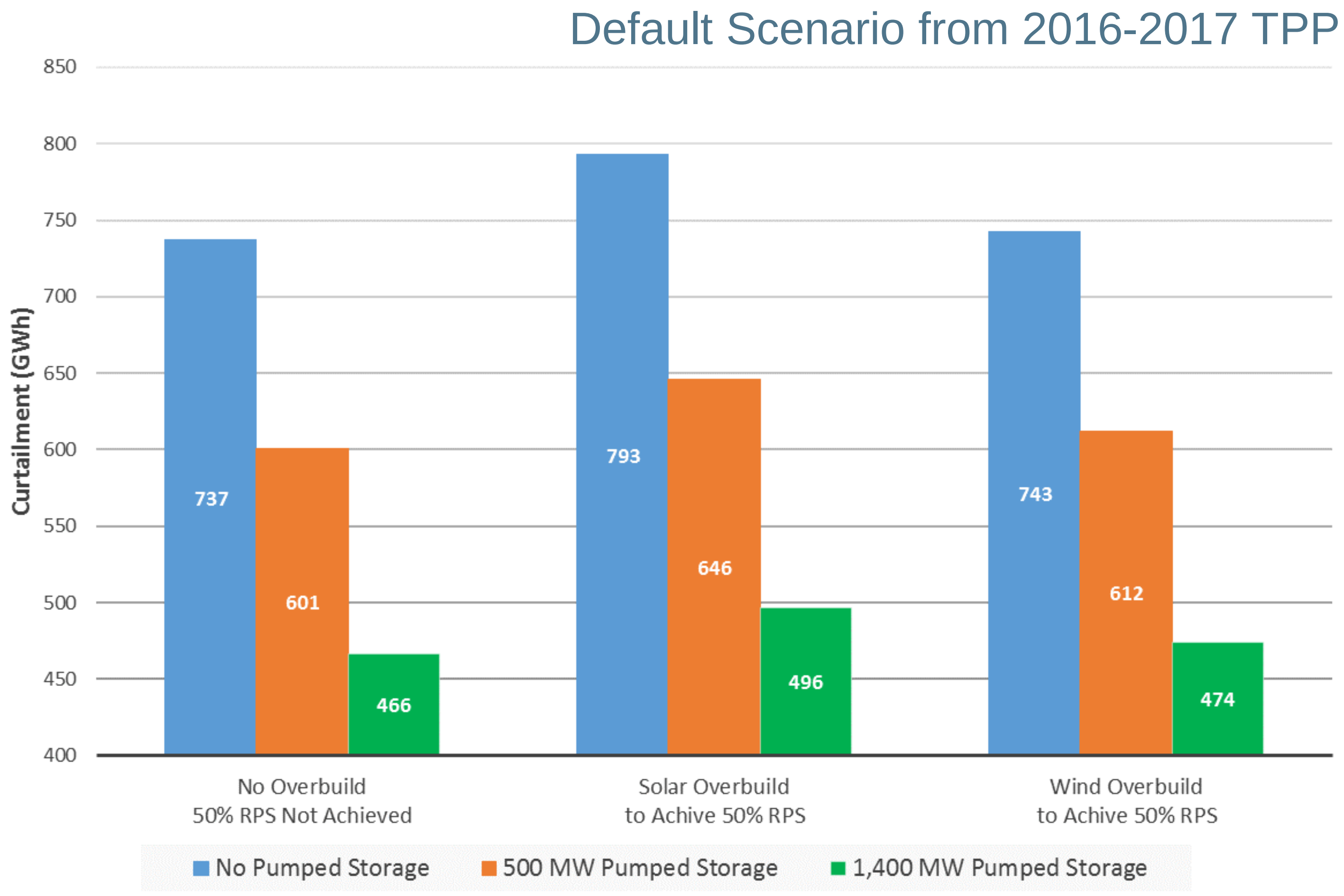
Case	Definition
A	Base Case, no pumped storage and no renewable overbuild
B500	Base Case plus a 500 MW pumped storage resource
B1400	Base Case plus a 1,400 MW pumped storage resource
C	Base Case with solar overbuild
D	Base Case with wind overbuild
E500	Base Case with solar overbuild and a 500 MW pumped storage resource
E1400	Base Case with solar overbuild and a 1,400 MW pumped storage resource
F500	Base Case with wind overbuild and a 500 MW pumped storage resource
F1400	Base Case with wind overbuild and a 1,400 MW pumped storage resource

Recap of results from 2016-2017 TPP
– Default Scenario

Capacity of renewable overbuild to achieve the 50% RPS target

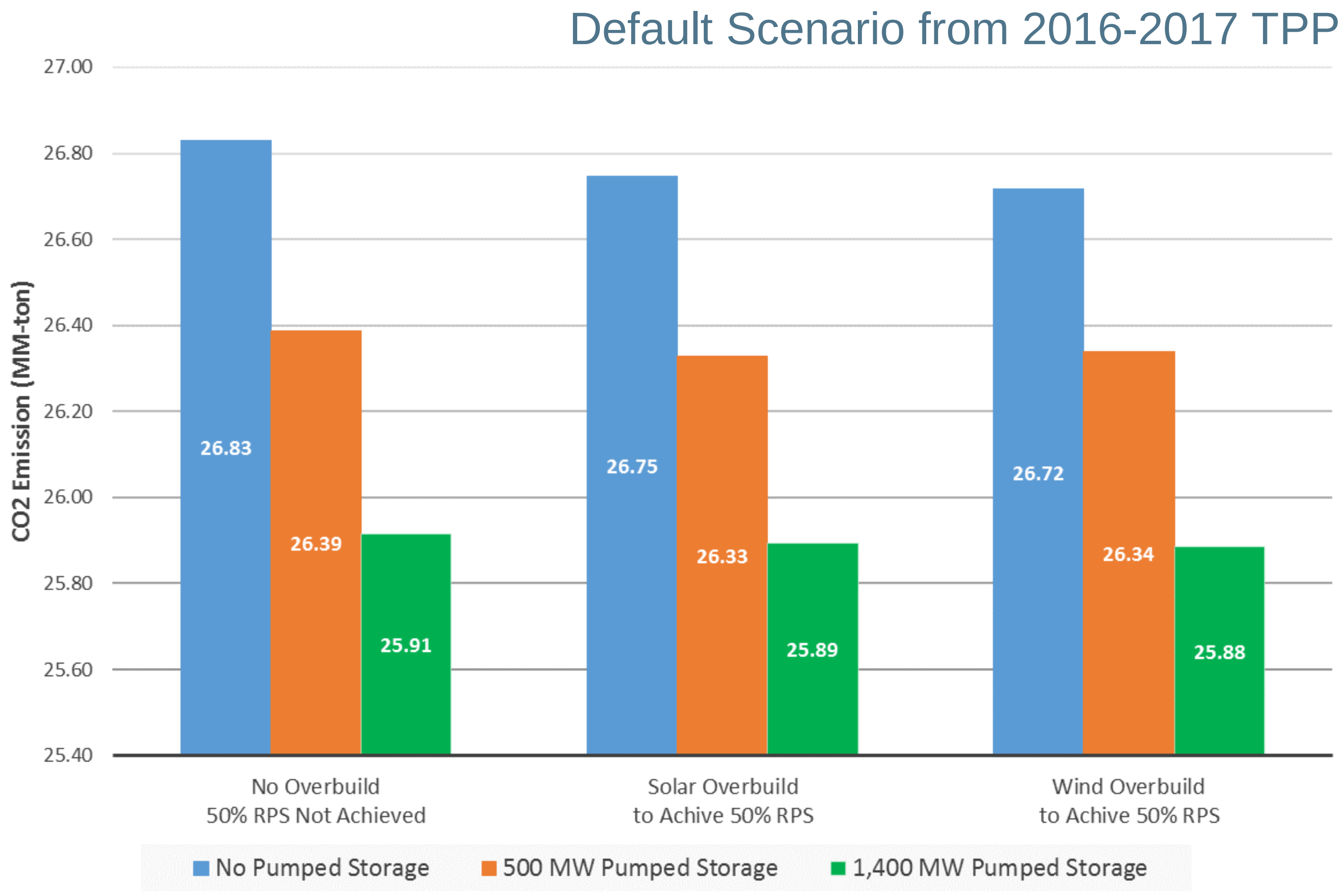


California renewable generation curtailment



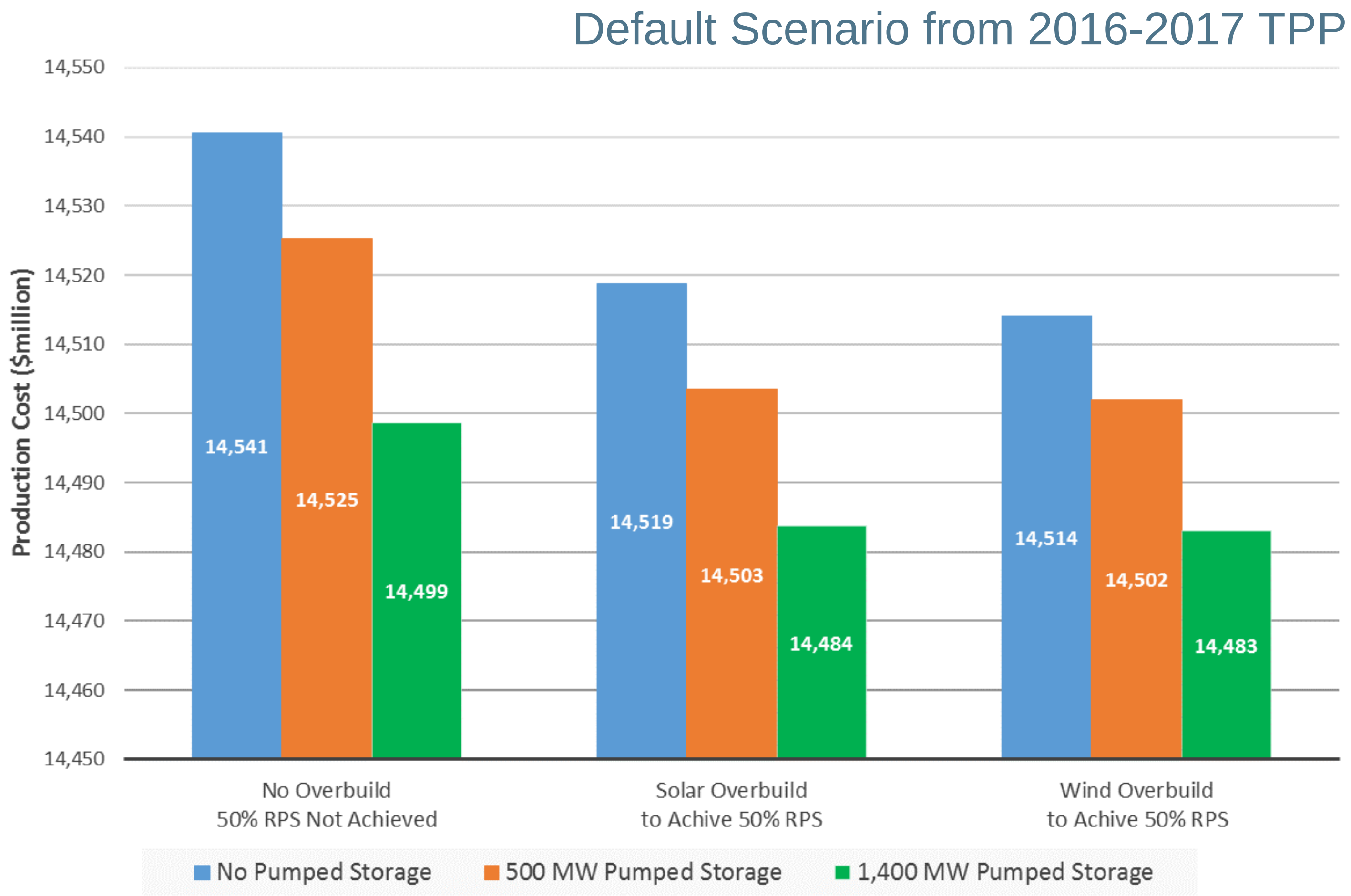
Renewable curtailment price is assumed as -$15/MWh for the first 200 GWh and -$25/MWh for additional 12,400 GWh.

California CO2 emission



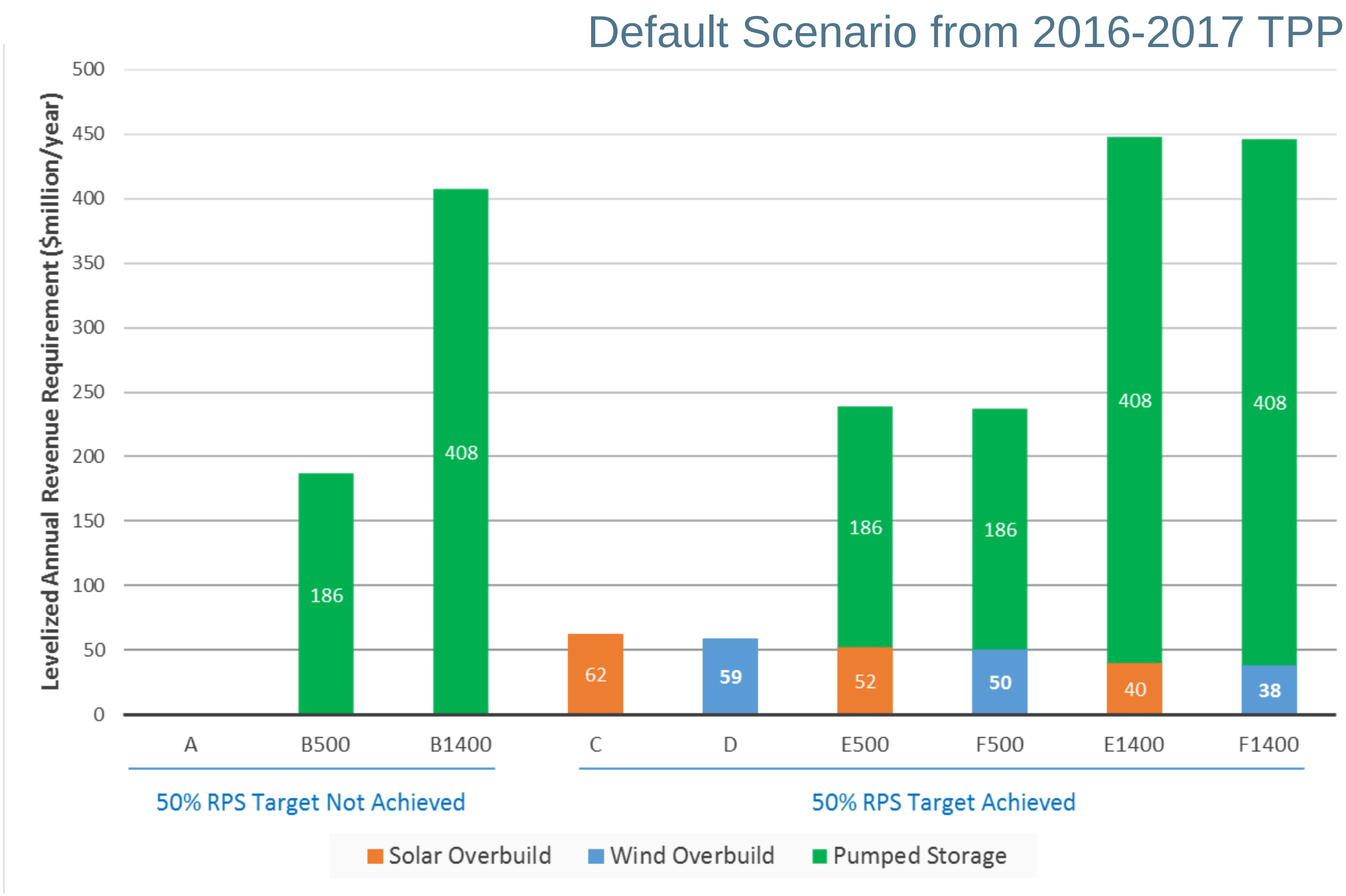
CA CO2 Emission includes the CO2 emission from net import

WECC annual production cost



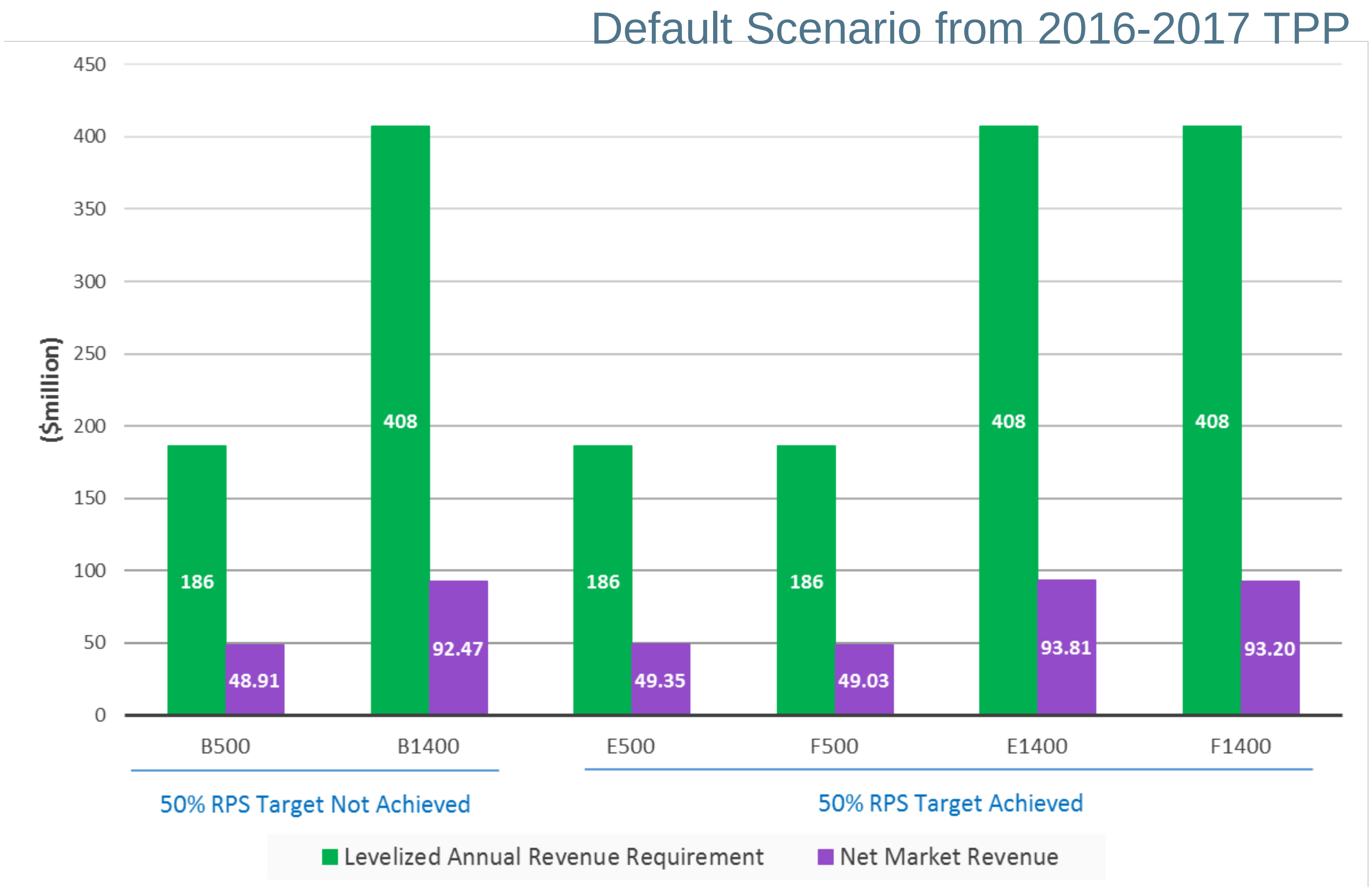
Production cost includes start-up, fuel and VOM cost, but not CO2 cost.

Levelized annual revenue requirements of renewable overbuild and the pumped storage resources



Cost of the 1,400 MW pumped storage is discounted by 20% based on economies of scale assumption

Pumped storage levelized annual revenue requirements and net market revenues of 2026



Net Market Revenue is revenue from energy, reserves and load following minus cost of energy and operation

Summary of annual results by case

Default Scenario from 2016-2017 TPP

	No Pumped Storage			500 MW Pumped Storage			1,400 MW Pumped Storage		
Case	**A**	**C**	**D**	**B500**	**E500**	**F500**	**B1400**	**E1400**	**F1400**
Renewable Curtailment (GWh)	737	793	743	601	646	612	466	496	474
Curtailment Frequency (hours)	292	320	305	251	268	253	211	219	207
CA CO2 Emission (MM-ton)	26.83	26.75	26.72	26.39	26.33	26.34	25.91	25.89	25.88
CA CO2 Emission ($million)	606	604	604	596	595	595	585	585	585
Production Cost ($million)									
WECC	14,541	14,519	14,514	14,525	14,503	14,502	14,499	14,484	14,483
CA	2,999	2,989	2,986	2,952	2,945	2,946	2,900	2,898	2,897
Renewable Overbuild and Pumped Storage Capacity (MW)									
Solar		275			231			179	
Wind			257			220			166
Pumped Storage				500	500	500	1,400	1,400	1,400
Levelized Annual Revenue Requirement of Renewable Overbuild and Pumped Storage ($million/year)									
Solar		62.11			52.17			40.43	
Wind			58.89			50.41			38.04
Pumped Storage				186.37	186.37	186.37	407.61	407.61	407.61
Sum		*62.11*	*58.89*	*186.37*	*238.54*	*236.78*	*407.61*	*448.04*	*445.65*
Pumped Storage Net Market Revenue ($million)				48.91	49.35	49.03	92.47	93.81	93.20

Notes:

1. Renewable curtailment price is assumed as -$15/MWh for the first 200 GWh and -$25/MWh for additional 12,400 GWh.
2. CA CO2 Emission includes the CO2 emission from net import.
3. CO2 cost is $22.59/M-ton.
4. Production cost includes start-up, fuel and VOM cost, but not CO2 cost.
5. Net Market Revenue is revenue from energy, reserves and load following minus cost of energy and operation.

Findings of system benefits

- Compared to the study with 50% RPS in 2015-2016 TPP, results of this study show significantly lower renewable curtailment, mainly due to
  – Retirement of Diablo Canyon and non-dispatchable CHP resources
  – Dispatchability of 50% of CHP resources
  – Lower load forecast together with higher AAEE, and the resulted lower renewable energy needed to achieve the 50% RPS target

Findings of system benefits (cont.)

- Because of low renewable curtailment, the effectiveness of the pumped storage resources in reducing renewable curtailment, CO_2 emission and production costs is limited
- Besides lower curtailment, the net market revenues of the pumped storages are also affected by the higher renewable curtailment prices

Findings of system benefits (cont.)

- The net market revenue of the pumped storage resources provides only a portion of the levelized annual revenue requirements
- Developing pumped storage resources would need other sources of revenue streams, which could be developed through policy decisions

Findings of system benefits (cont.)

- The following annual system cost reductions (benefits) are not included in the net market revenue, but may be attribute to the pumped storage resources

	500 MW Pumped Storage		1,400 MW Pumped Storage	
Case	**E500**	**F500**	**E1400**	**F1400**
CA CO2 Emission ($million)	-9.45	-8.50	-19.25	-18.79
Production Cost ($million)				
WECC	-15.30	-11.96	-35.03	-30.96
CA	-44.05	-39.59	-91.49	-89.01
Levelized Annual Revenue Requirement of Renewable Overbuild ($million/year)				
Solar	-9.94		-21.68	
Wind		-8.48		-20.85

Next steps

- The results of the study are sensitive to the assumptions, especially those listed in the tables on slide 6 and 7
- There are uncertainties in some of these assumptions
- The conclusions about the benefits and costs of the pumped storage resources could change should the assumptions change in the future
- The ISO will conduct sensitivity analyses at least on
  - Dispatchability of CHP resource
  - Level of AAEE
  - Prices of renewable curtailment

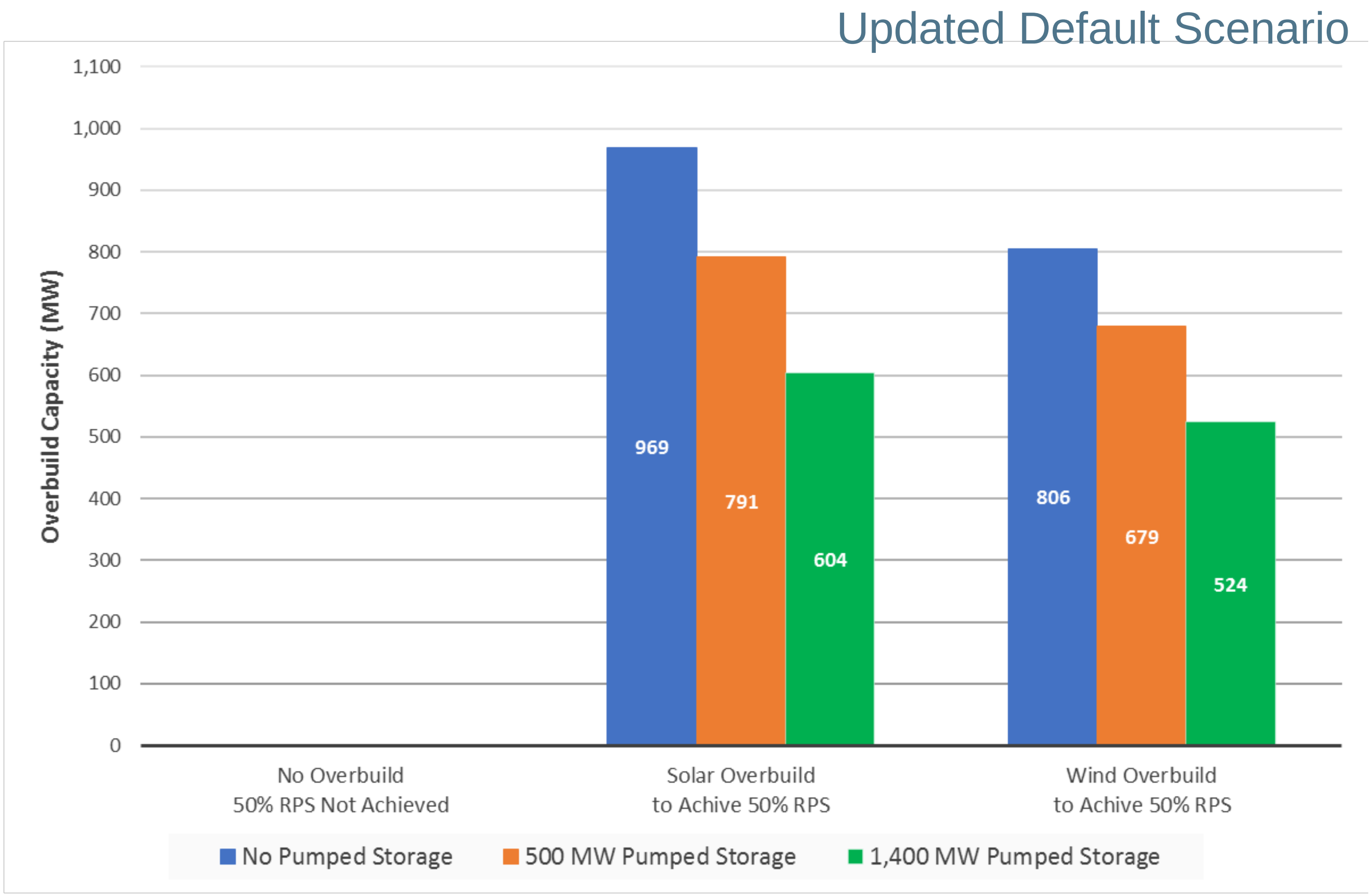
New updates and sensitivities

Update to the Default Scenario

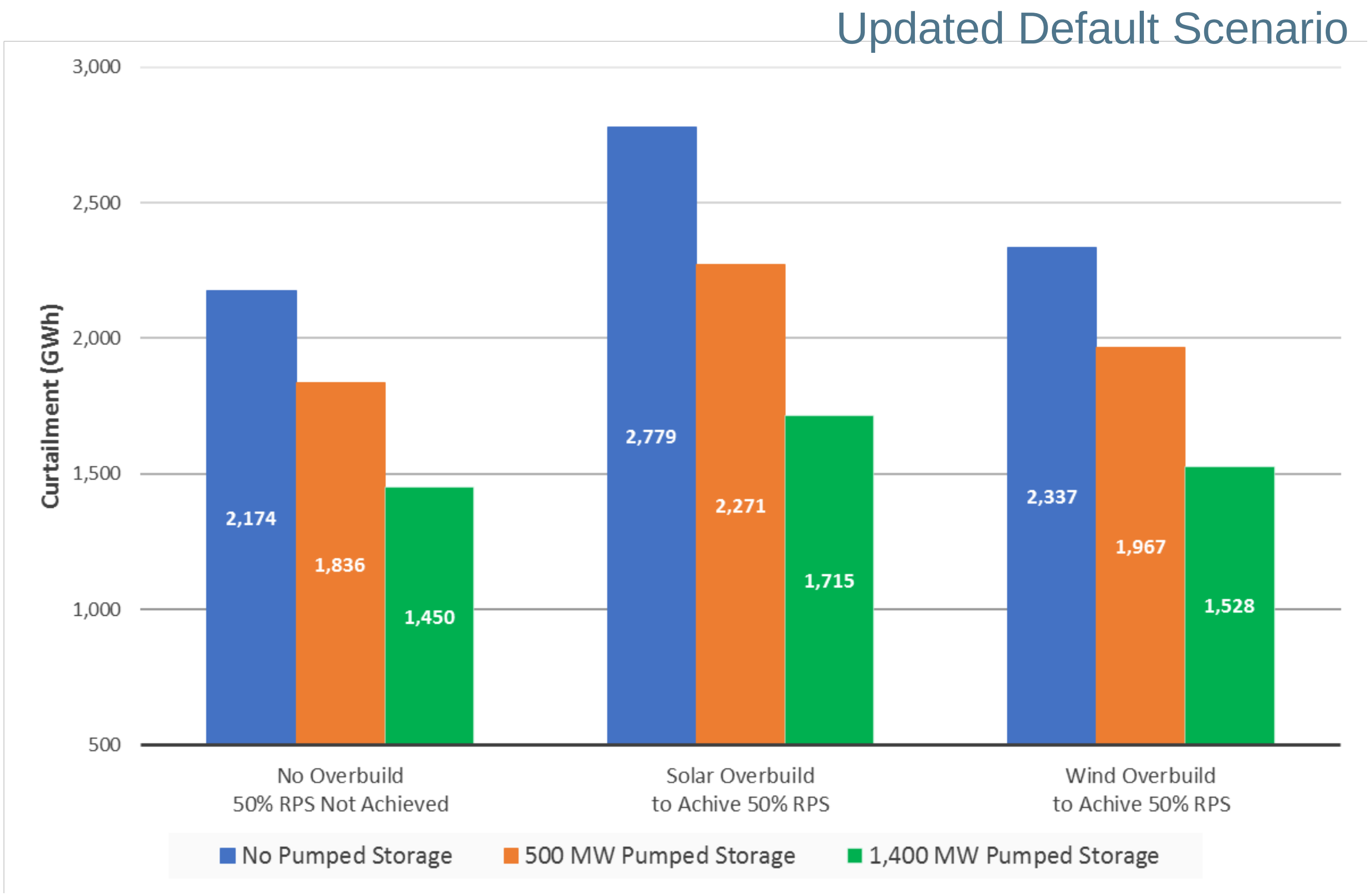
The Default Scenario was updated after the initial results were presented to the stakeholders

- Changing the import from out-of-state RPS resources
  - It assumes that 70% of out-of-state RPS generation needs to be imported into the CAISO
  - The Default Scenario in 2016-2017 TPP allows the import to be exported back
  - This update changes the RPS import into Category 1 and 2 RPS, which has to stay in the CAISO
  - The change reduces allowed net export when there is curtailment of renewable generation in the CAISO

Capacity of renewable overbuild to achieve the 50% RPS target

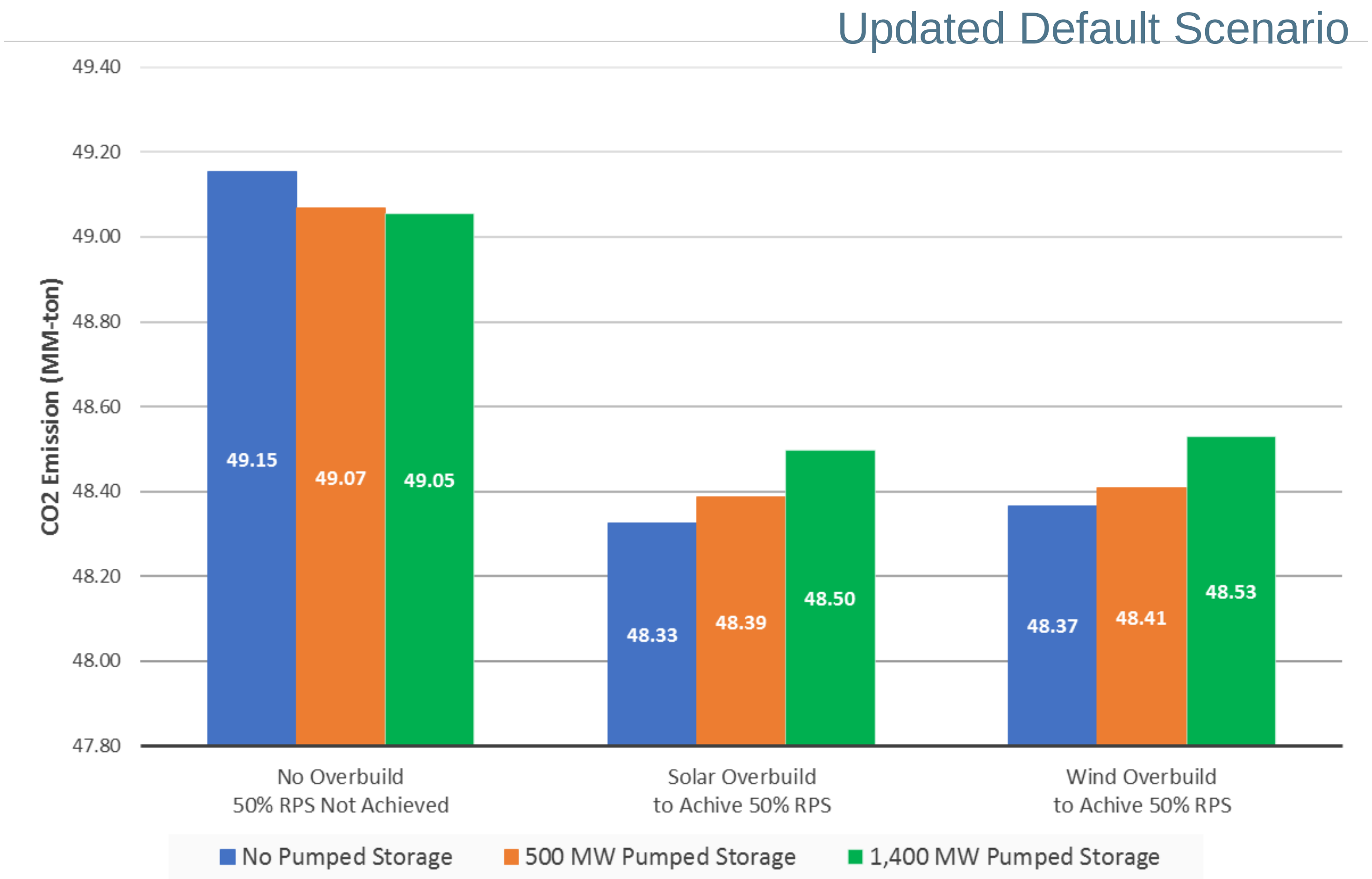


California renewable generation curtailment



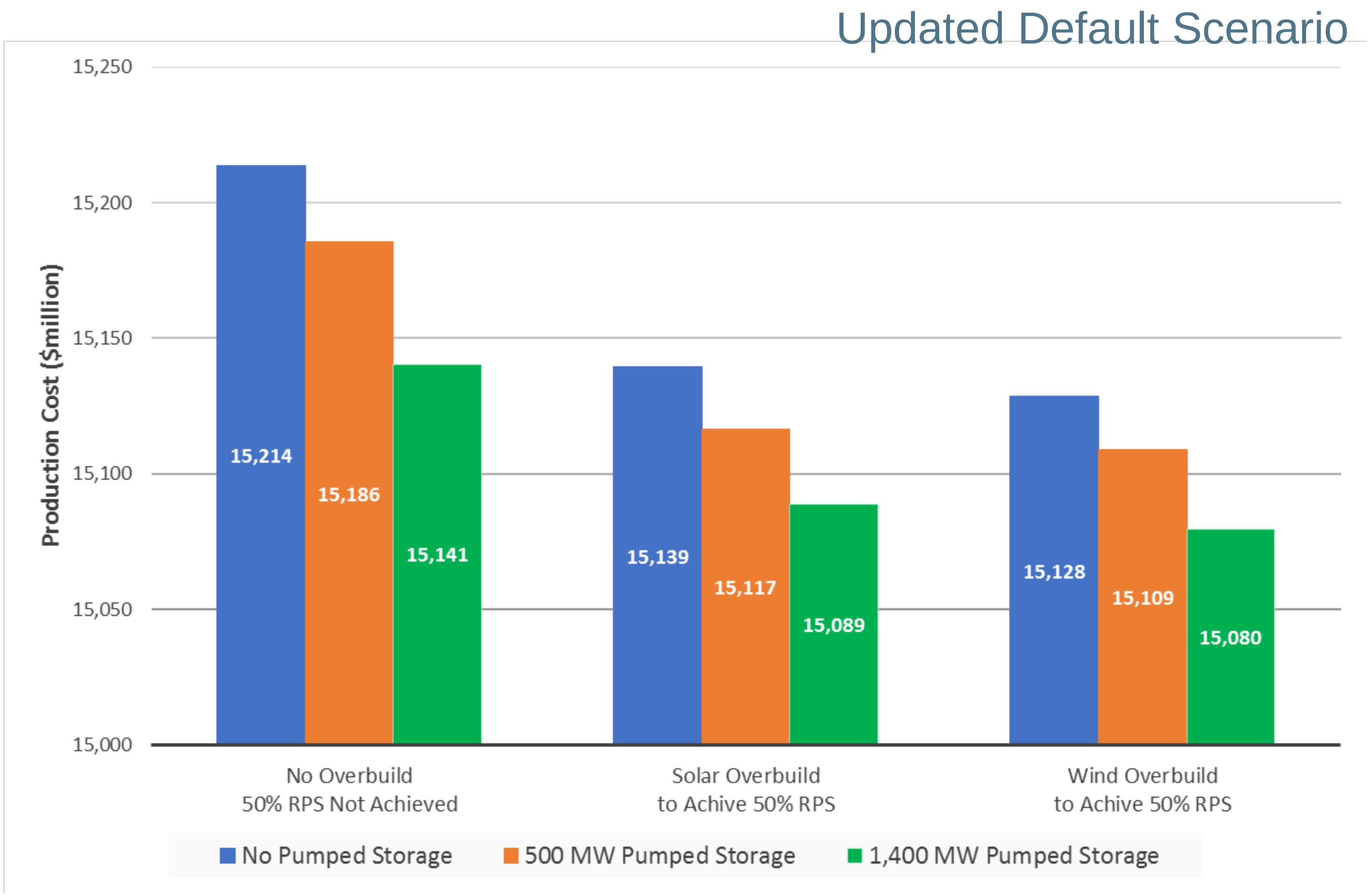
Renewable curtailment price is assumed as -$15/MWh for the first 200 GWh and -$25/MWh for additional 12,400 GWh.

California CO2 emission



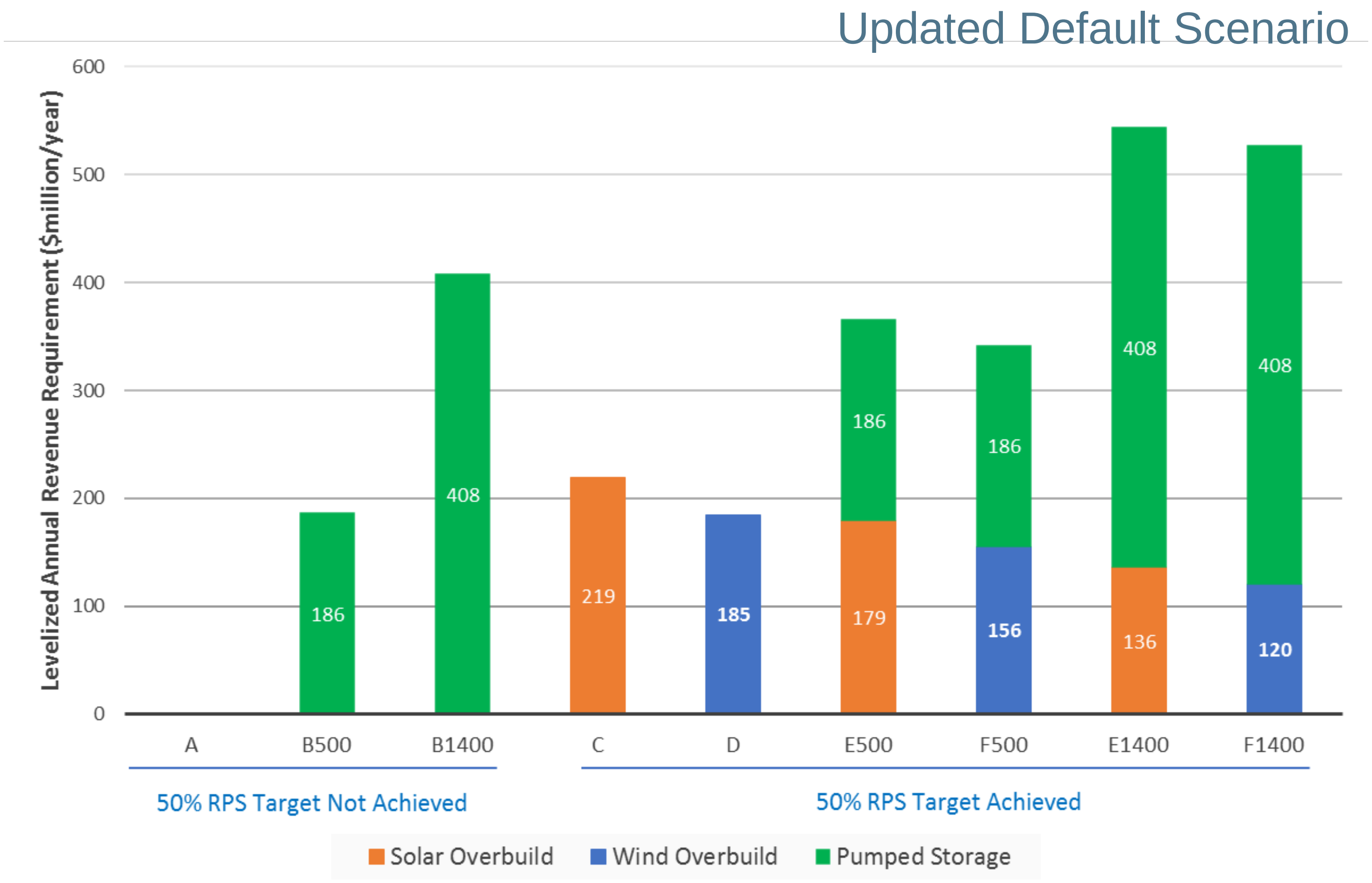
CA CO2 Emission includes the CO2 emission from net import

WECC annual production cost



Production cost includes start-up, fuel and VOM cost, but not CO2 cost.

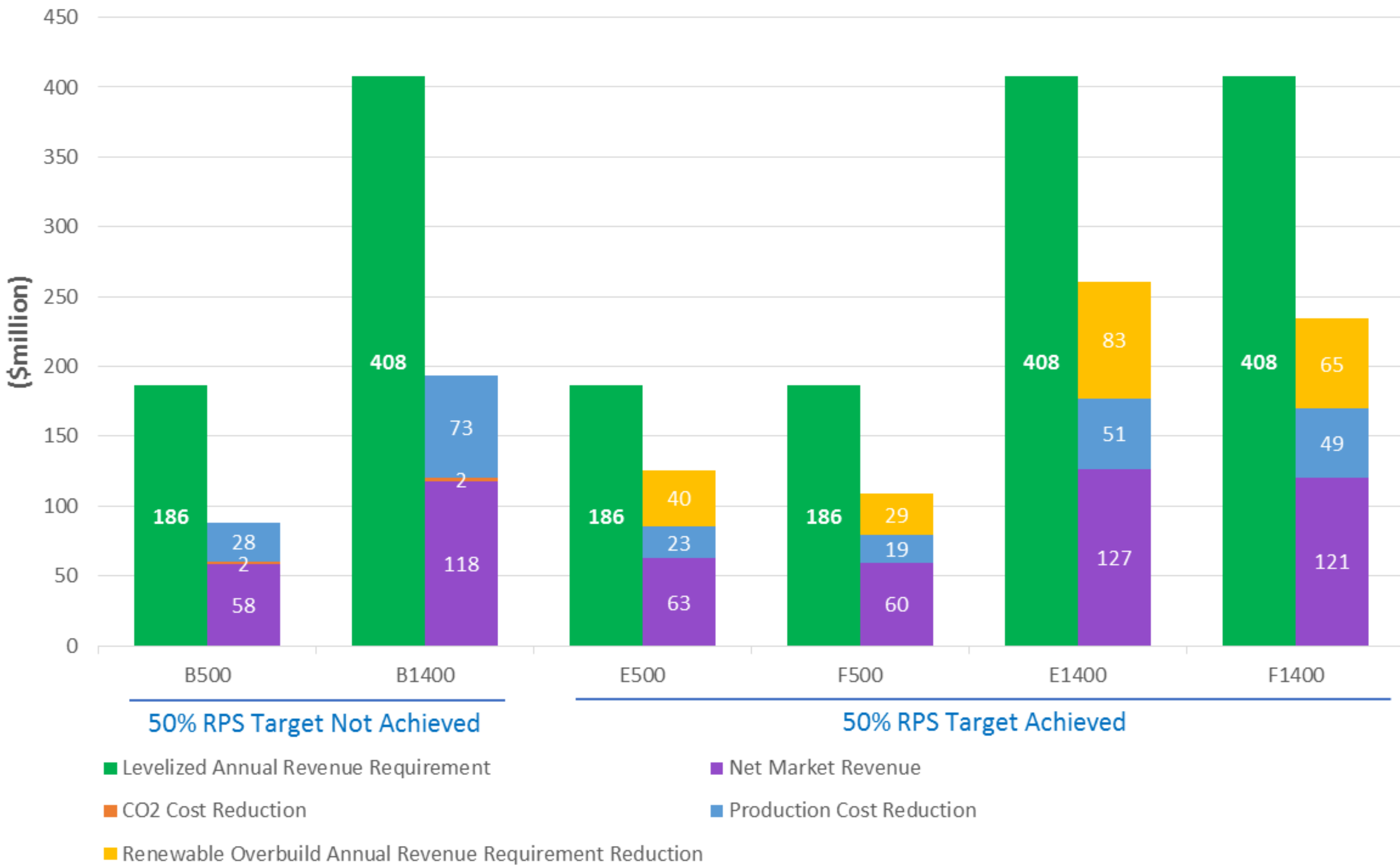
Levelized annual revenue requirements of renewable overbuild and the pumped storage resources



Cost of the 1,400 MW pumped storage is discounted by 20% based on economies of scale assumption

Pumped storage levelized annual revenue requirements, net market revenues and system benefits of 2026

Updated Default Scenario



Net Market Revenue is revenue from energy, reserves and load following minus cost of energy and operation.
System benefits includes reduction of CO_2 emission cost, WECC production cost and renewable overbuild cost

Summary of annual results by case

Updated Default Scenario

Case	No Pumped Storage			500 MW Pumped Storage			1,400 MW Pumped Storage		
Case	A	C	D	B500	E500	F500	B1400	E1400	F1400
Renewable Curtailment (GWh)	2,174	2,779	2,337	1,836	2,271	1,967	1,450	1,715	1,528
Curtailment Frequency (hours)	672	806	722	601	704	631	487	554	502
CA CO2 Emission (MM-ton)	49.2	48.3	48.4	49.1	48.4	48.4	49.1	48.5	48.5
CA CO2 Emission ($million)	1,110	1,092	1,093	1,108	1,093	1,094	1,108	1,096	1,096
Production Cost ($million)									
WECC	15,214	15,139	15,128	15,186	15,117	15,109	15,141	15,089	15,080
CA	3,583	3,543	3,534	3,543	3,495	3,494	3,465	3,436	3,429
Renewable Overbuild and Pumped Storage Capacity (MW)									
Solar		969			791			597	
Wind			806			679			526
Pumped Storage				500	500	500	1,400	1,400	1,400
Levelized Annual Revenue Requirement of Renewable Overbuild and Pumped Storage ($million/year)									
Solar		219			179			136	
Wind			185			156			120
Pumped Storage				186	186	186	408	408	408
Sum		*219*	*185*	*186*	*365*	*342*	*408*	*544*	*528*
Pumped Storage Net Market Revenue ($million)				58	63	60	118	127	121
System Benefits by the Pumped Storage Resource ($million)				28	63	49	73	134	114

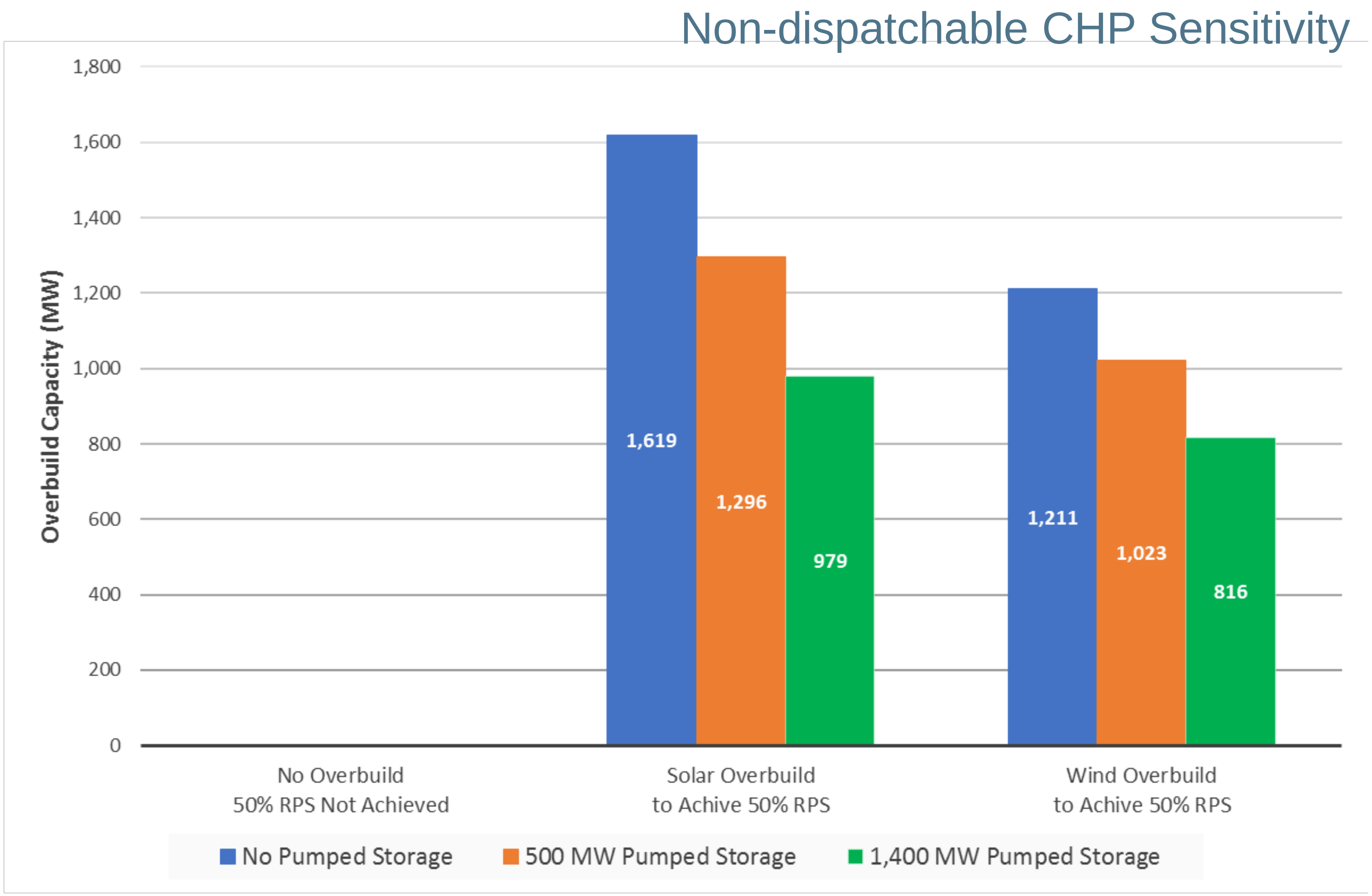
Notes:
1. Renewable curtailment price is assumed as -$15/MWh for the first 200 GWh and -$25/MWh for additional 12,400 GWh.
2. CA CO2 Emission includes the CO2 emission from net import.
3. CO2 cost is $22.59/M-ton.
4. Production cost includes start-up, fuel and VOM cost, but not CO2 cost.
5. Net Market Revenue is revenue from energy, reserves and load following minus cost of energy and operation.

Default Scenario with non-dispatchable CHP

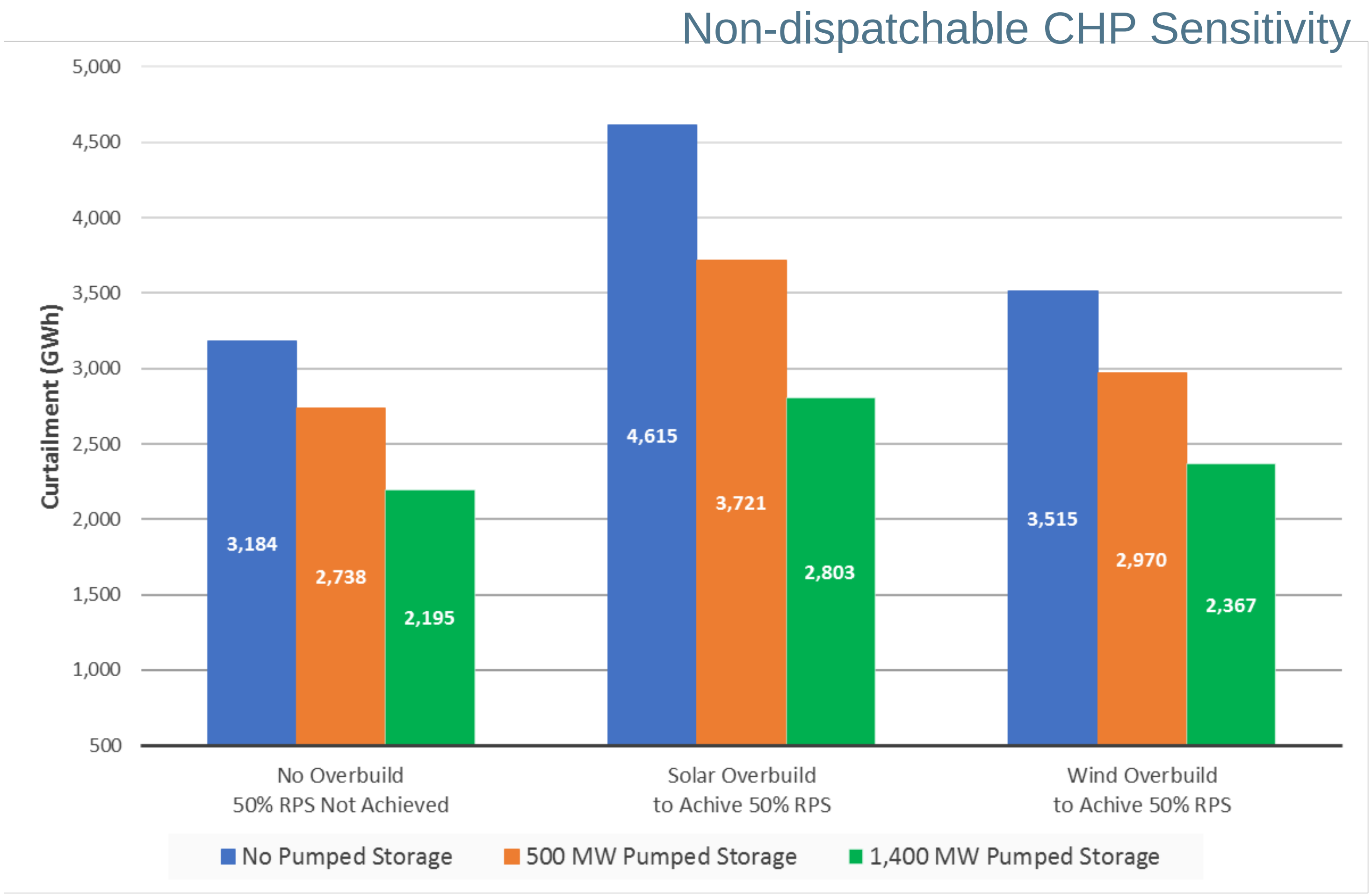
The sensitivity of non-dispatchable CHP

- Based on the updated Default Scenario, which assumes 50% of CHP resources are dispatchable
- In this sensitivity all CHP is assumed to be non-dispatchable

Capacity of renewable overbuild to achieve the 50% RPS target



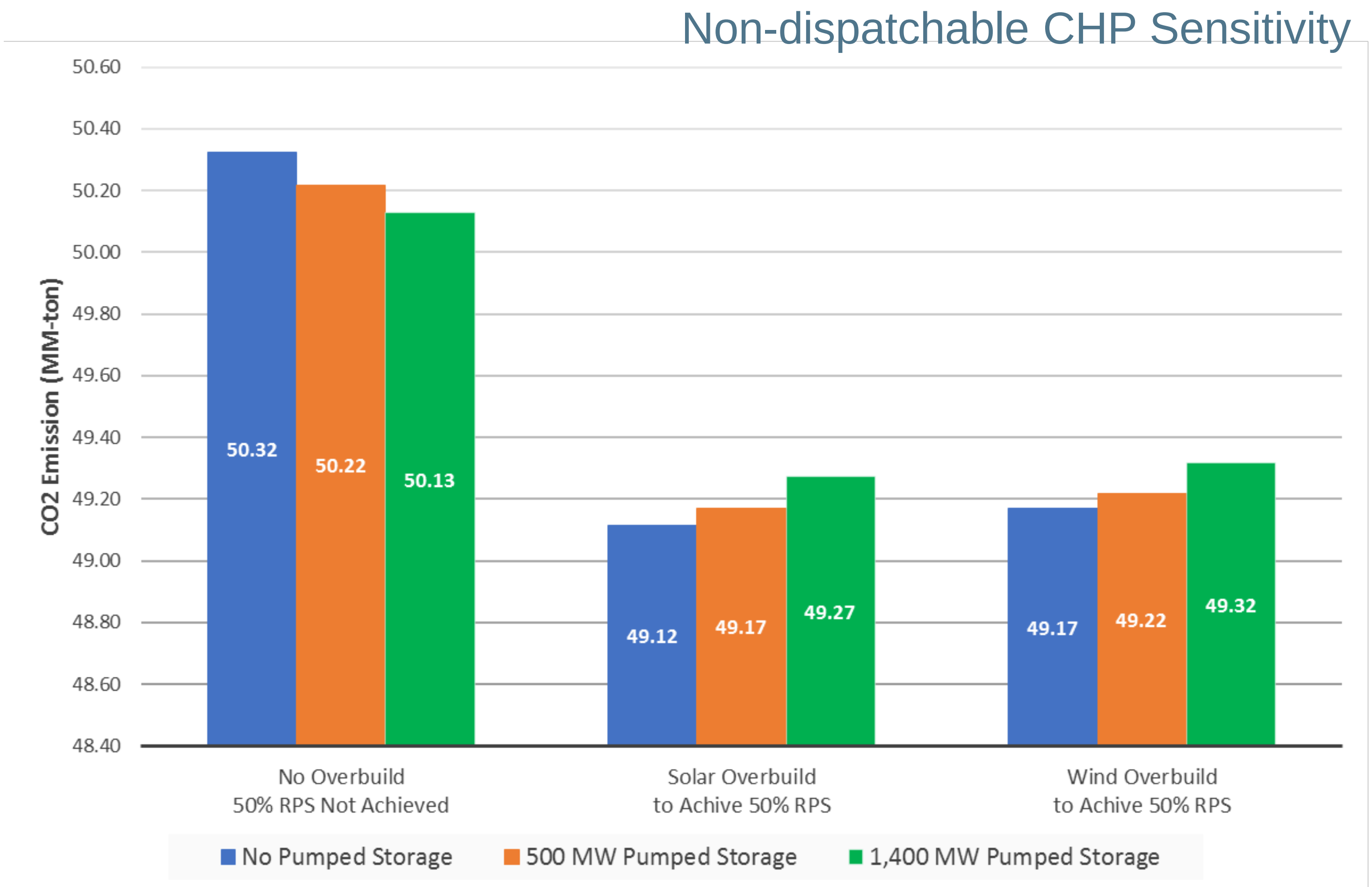
California renewable generation curtailment



Renewable curtailment price is assumed as -$15/MWh for the first 200 GWh and -$25/MWh for additional 12,400 GWh.

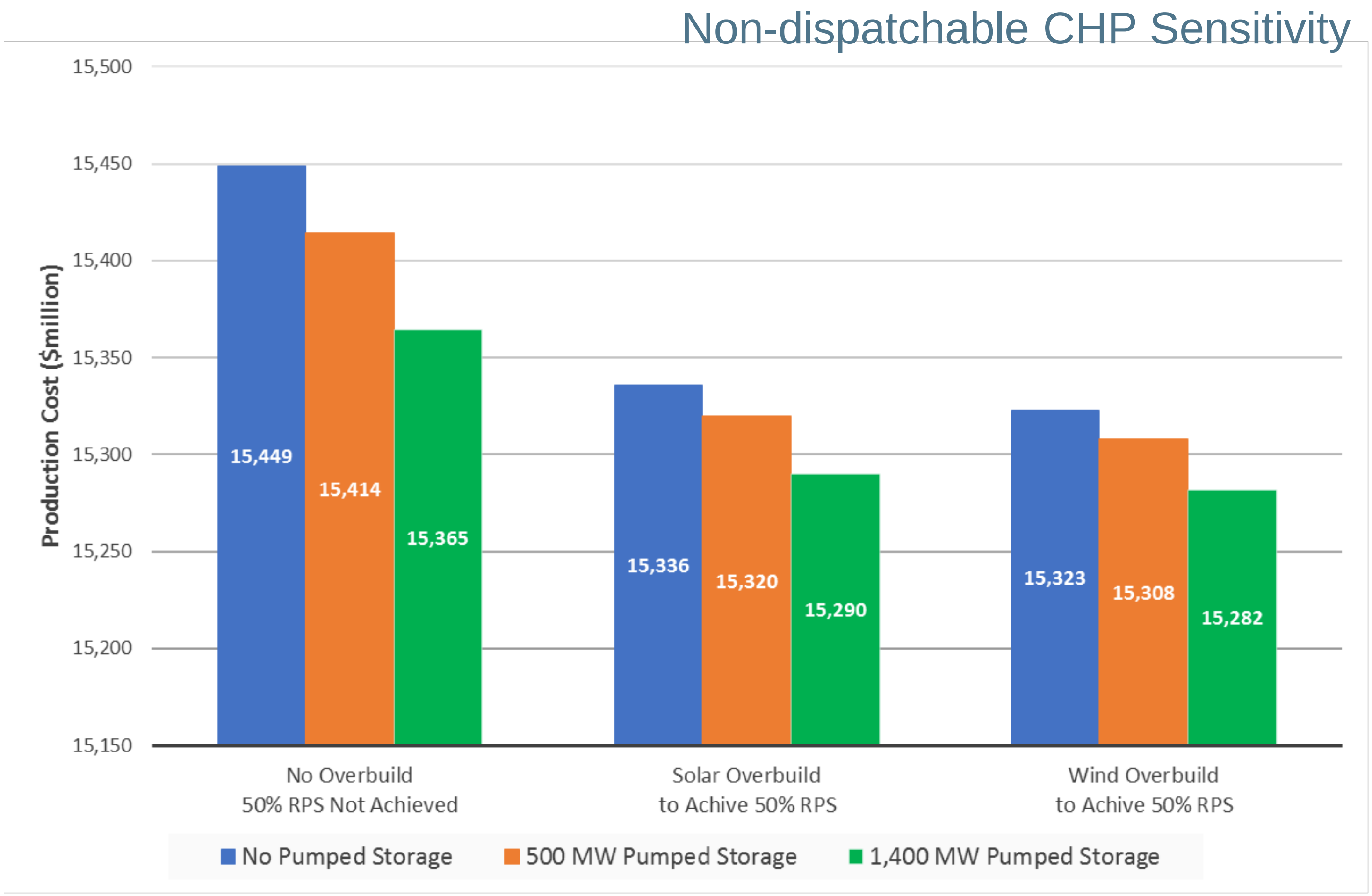
California ISO

California CO2 emission



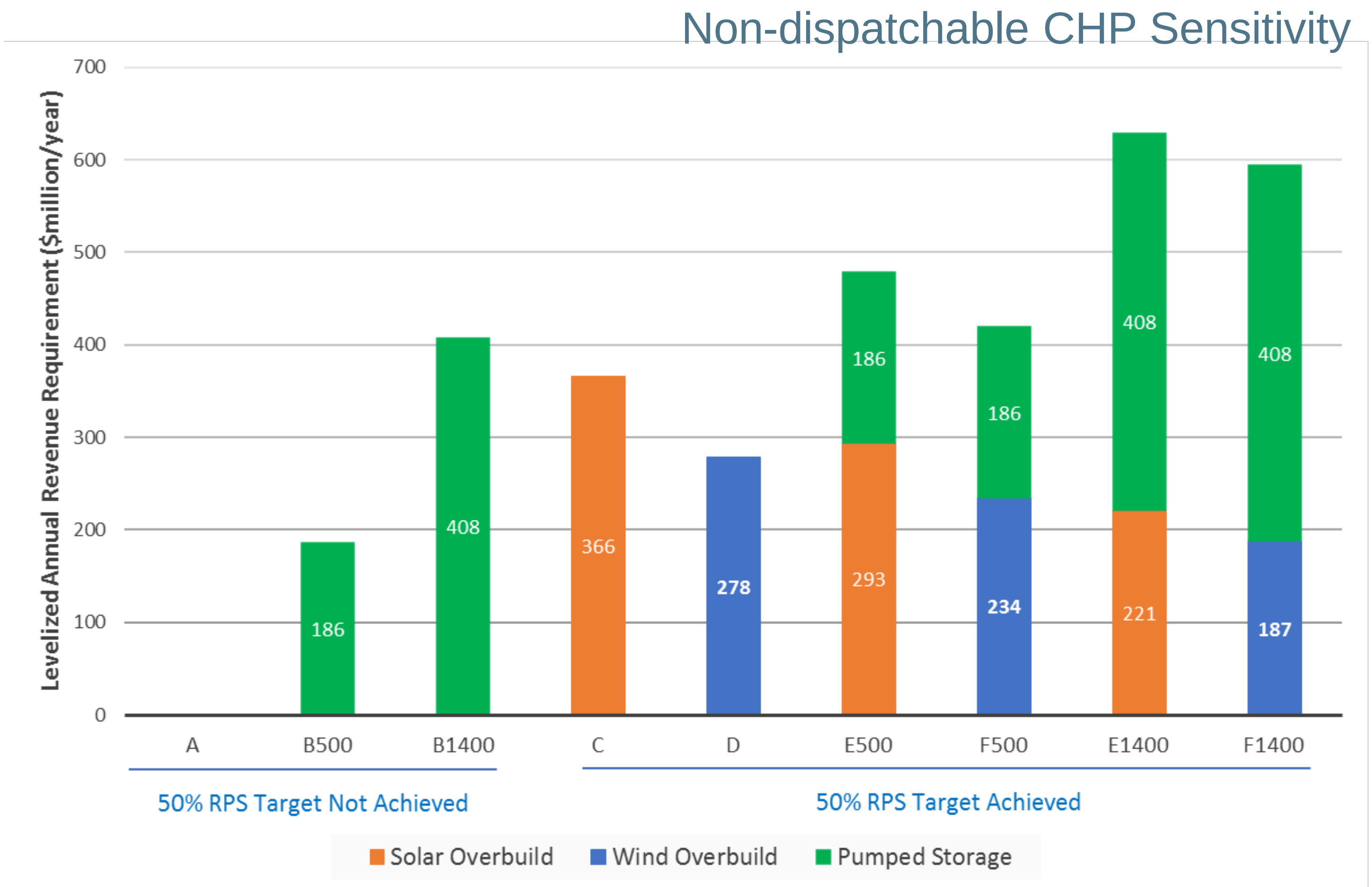
CA CO2 Emission includes the CO2 emission from net import

WECC annual production cost



Production cost includes start-up, fuel and VOM cost, but not CO2 cost.

Levelized annual revenue requirements of renewable overbuild and the pumped storage resources



Cost of the 1,400 MW pumped storage is discounted by 20% based on economies of scale assumption

Pumped storage levelized annual revenue requirements, net market revenues and system benefits of 2026

Non-dispatchable CHP Sensitivity

Net Market Revenue is revenue from energy, reserves and load following minus cost of energy and operation.
System benefits includes reduction of CO_2 emission cost, WECC production cost and renewable overbuild cost

Summary of annual results by case

Non-dispatchable CHP Sensitivity

	No Pumped Storage			500 MW Pumped Storage			1,400 MW Pumped Storage		
Case	A	C	D	B500	E500	F500	B1400	E1400	F1400
Renewable Curtailment (GWh)	3,184	4,615	3,515	2,738	3,721	2,970	2,195	2,803	2,367
Curtailment Frequency (hours)	911	1,176	964	787	990	830	672	786	695
CA CO2 Emission (MM-ton)	50.3	49.1	49.2	50.2	49.2	49.2	50.1	49.3	49.3
CA CO2 Emission ($million)	1,137	1,110	1,111	1,134	1,111	1,112	1,132	1,113	1,114
Production Cost ($million)									
WECC	15,449	15,336	15,323	15,414	15,320	15,308	15,365	15,290	15,282
CA	3,929	3,861	3,862	3,882	3,830	3,825	3,808	3,774	3,768
Renewable Overbuild and Pumped Storage Capacity (MW)									
Solar		1,619			1,296			979	
Wind			1,211			1,023			816
Pumped Storage				0	0	0	1,400	1,400	1,400
Levelized Annual Revenue Requirement of Renewable Overbuild and Pumped Storage ($million/year)									
Solar		366			293			221	
Wind			278			234			187
Pumped Storage				186	186	186	408	408	408
Sum		*366*	*278*	*186*	*479*	*420*	*408*	*629*	*595*
Pumped Storage Net Market Revenue ($million)				67	76	69	139	153	143
System Benefits by the Pumped Storage Resource ($million)				34	89	58	84	191	132

Notes:

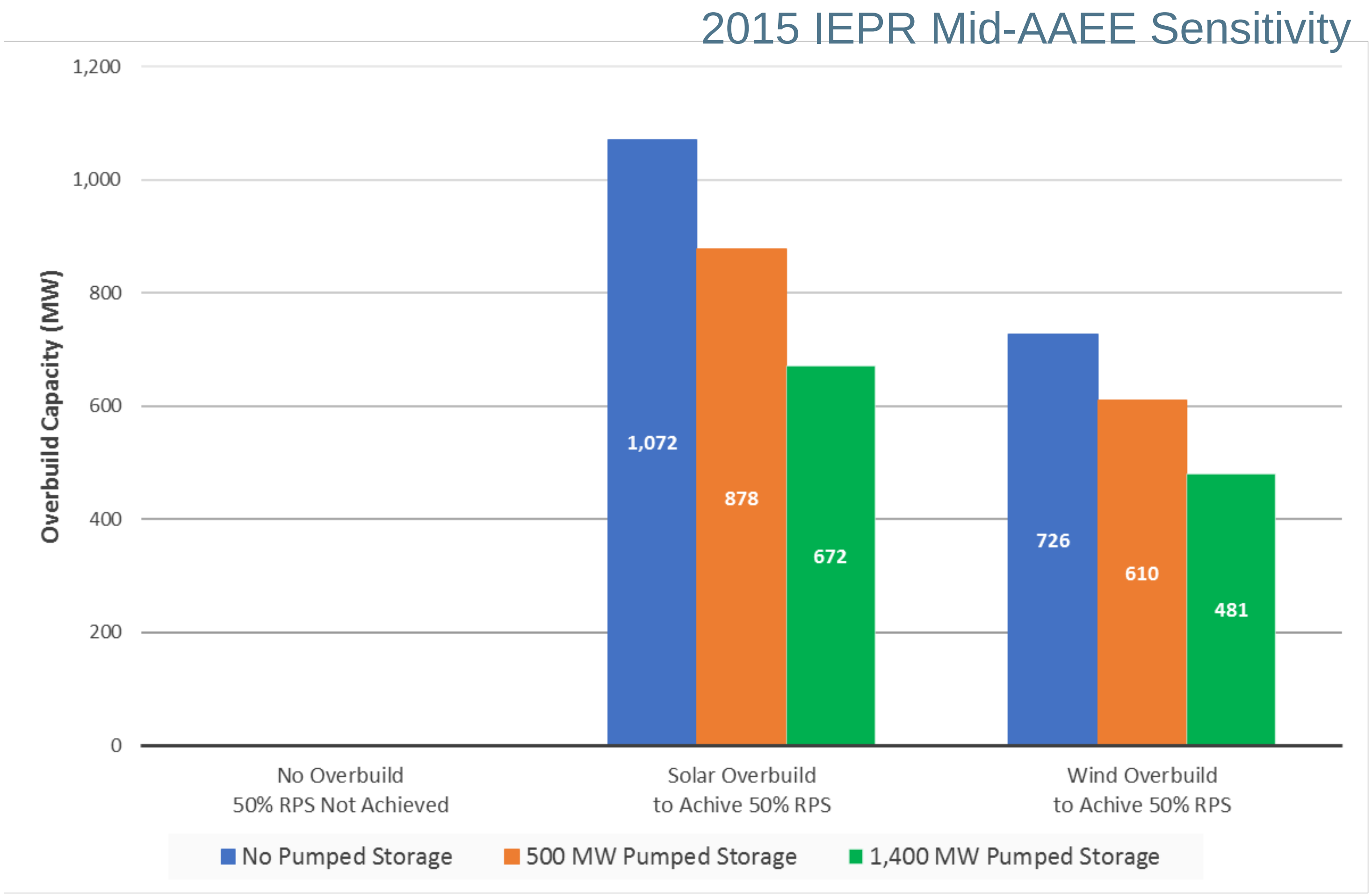
1. Renewable curtailment price is assumed as -$15/MWh for the first 200 GWh and -$25/MWh for additional 12,400 GWh.
2. CA CO2 Emission includes the CO2 emission from net import.
3. CO2 cost is $22.59/M-ton.
4. Production cost includes start-up, fuel and VOM cost, but not CO2 cost.
5. Net Market Revenue is revenue from energy, reserves and load following minus cost of energy and operation.

Default Scenario with 2015 IEPR Mid-AAEE

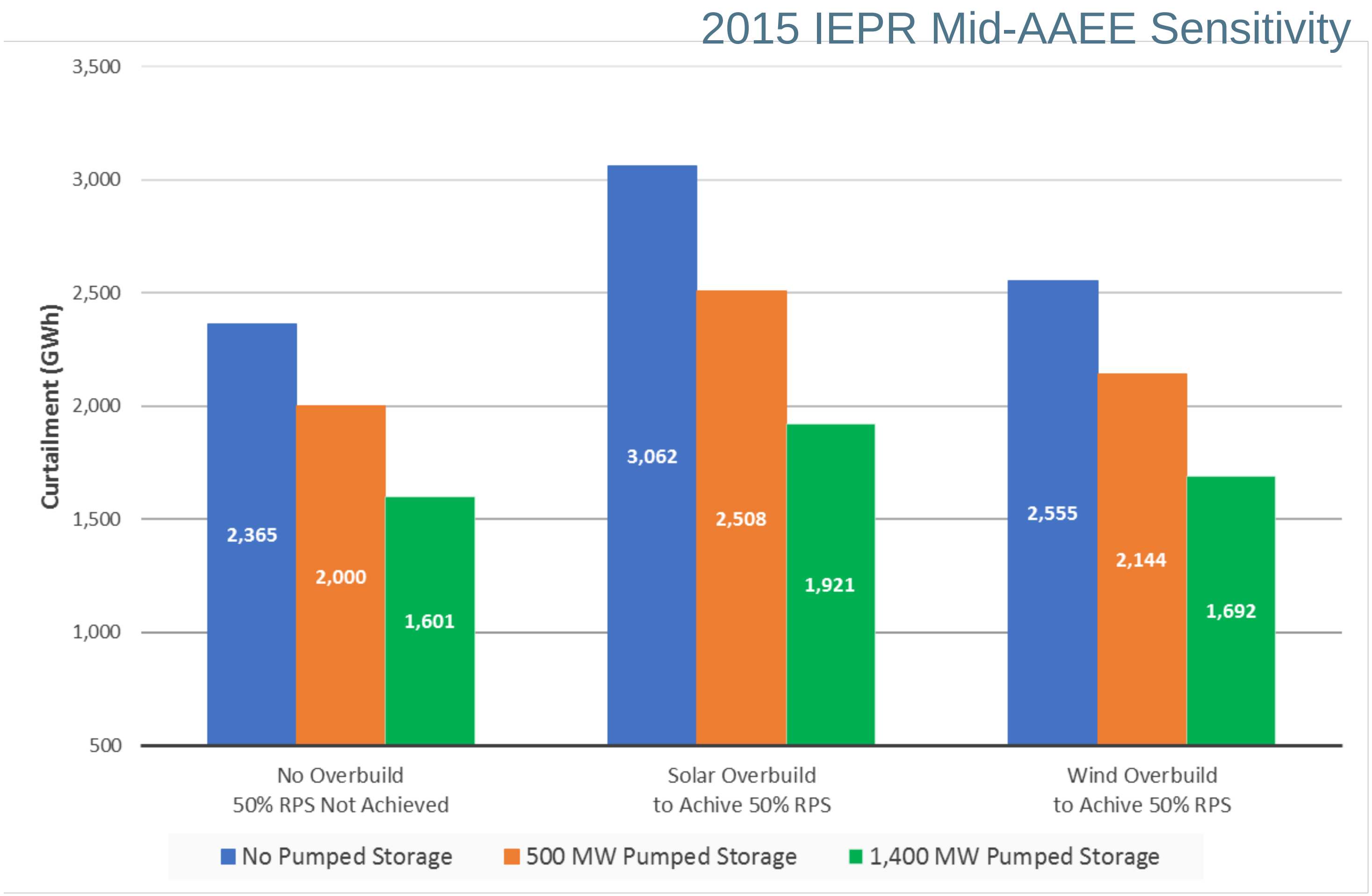
The case of non-dispatchable CHP

- Based on the updated Default Scenario, which assumes the 2015 IEPR Mid-AAEE will be doubled in 2030
- In this case the 2015 IEPR Mid-AAEE forecast for 2026 is used

Capacity of renewable overbuild to achieve the 50% RPS target

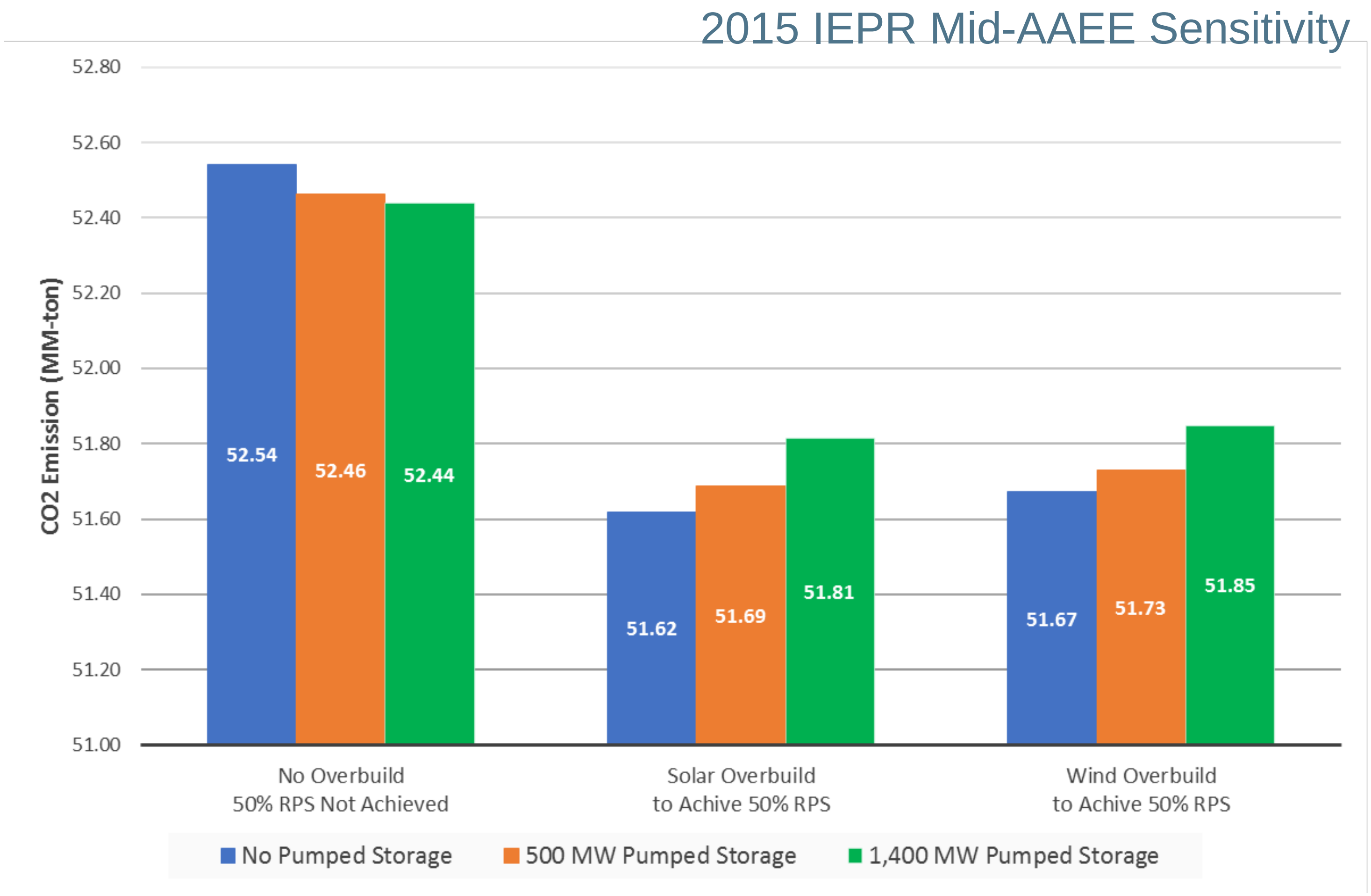


California renewable generation curtailment



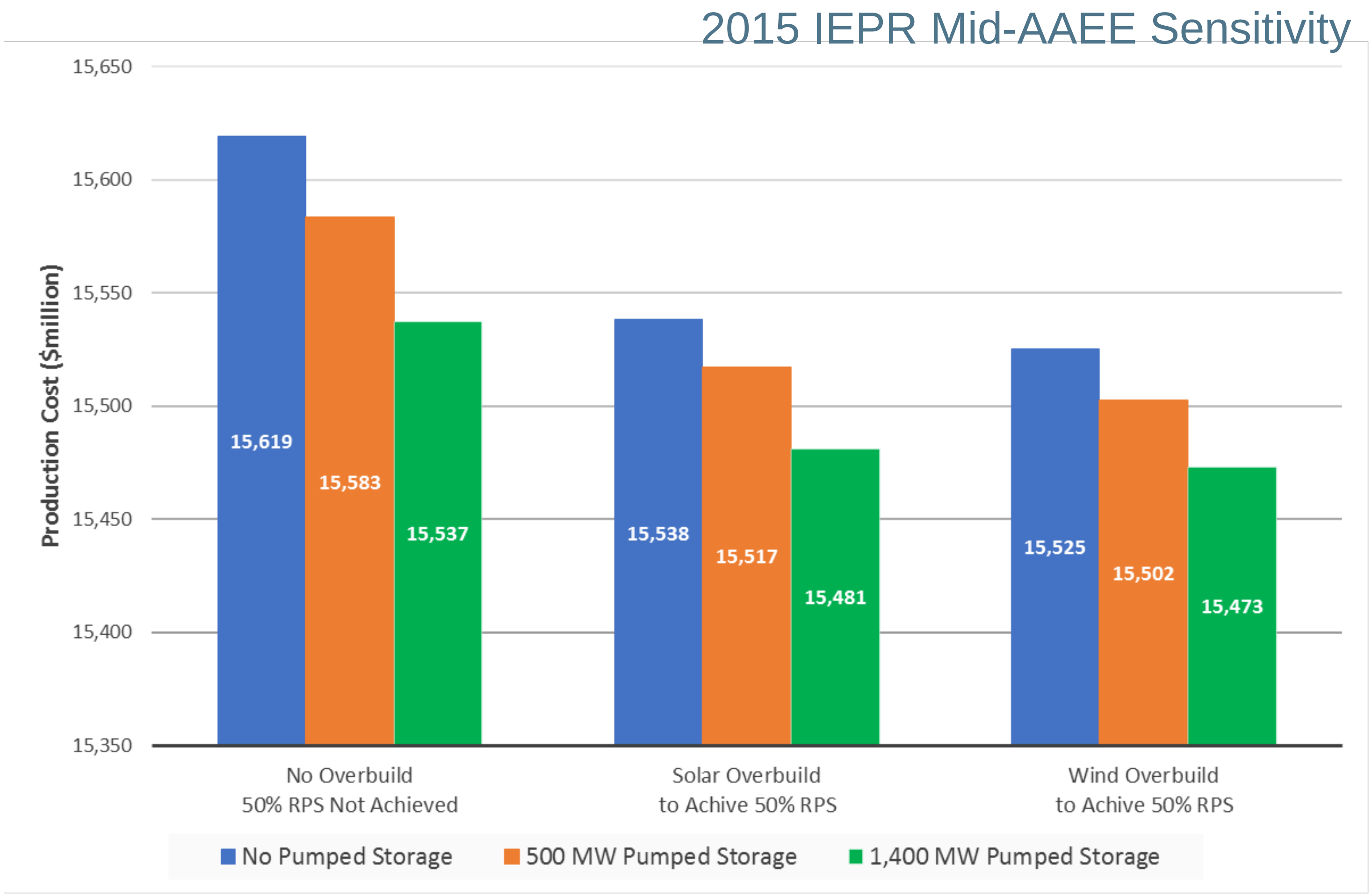
Renewable curtailment price is assumed as -$15/MWh for the first 200 GWh and -$25/MWh for additional 12,400 GWh.

California CO2 emission



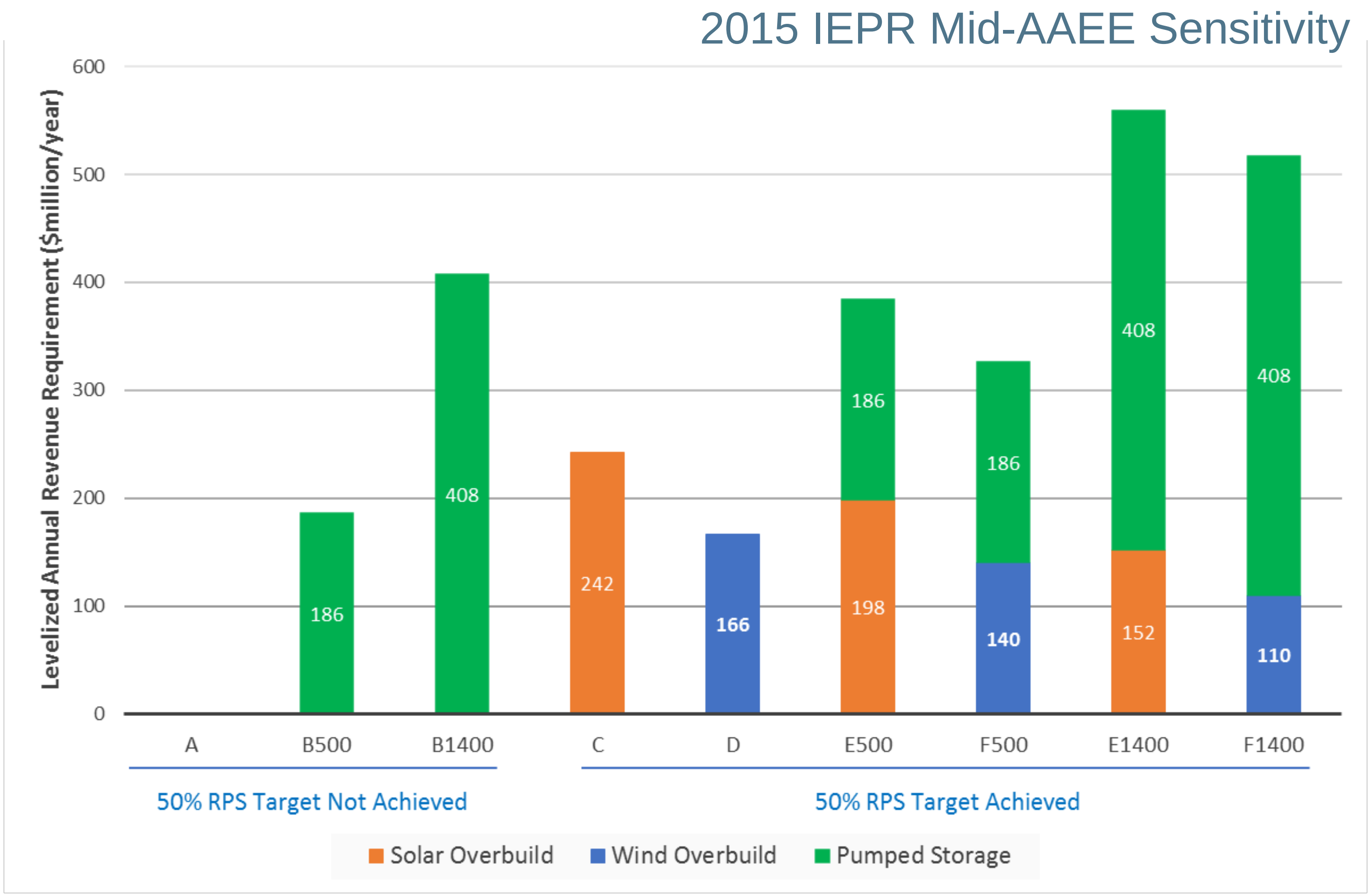
CA CO2 Emission includes the CO2 emission from net import

WECC annual production cost



Production cost includes start-up, fuel and VOM cost, but not CO2 cost.

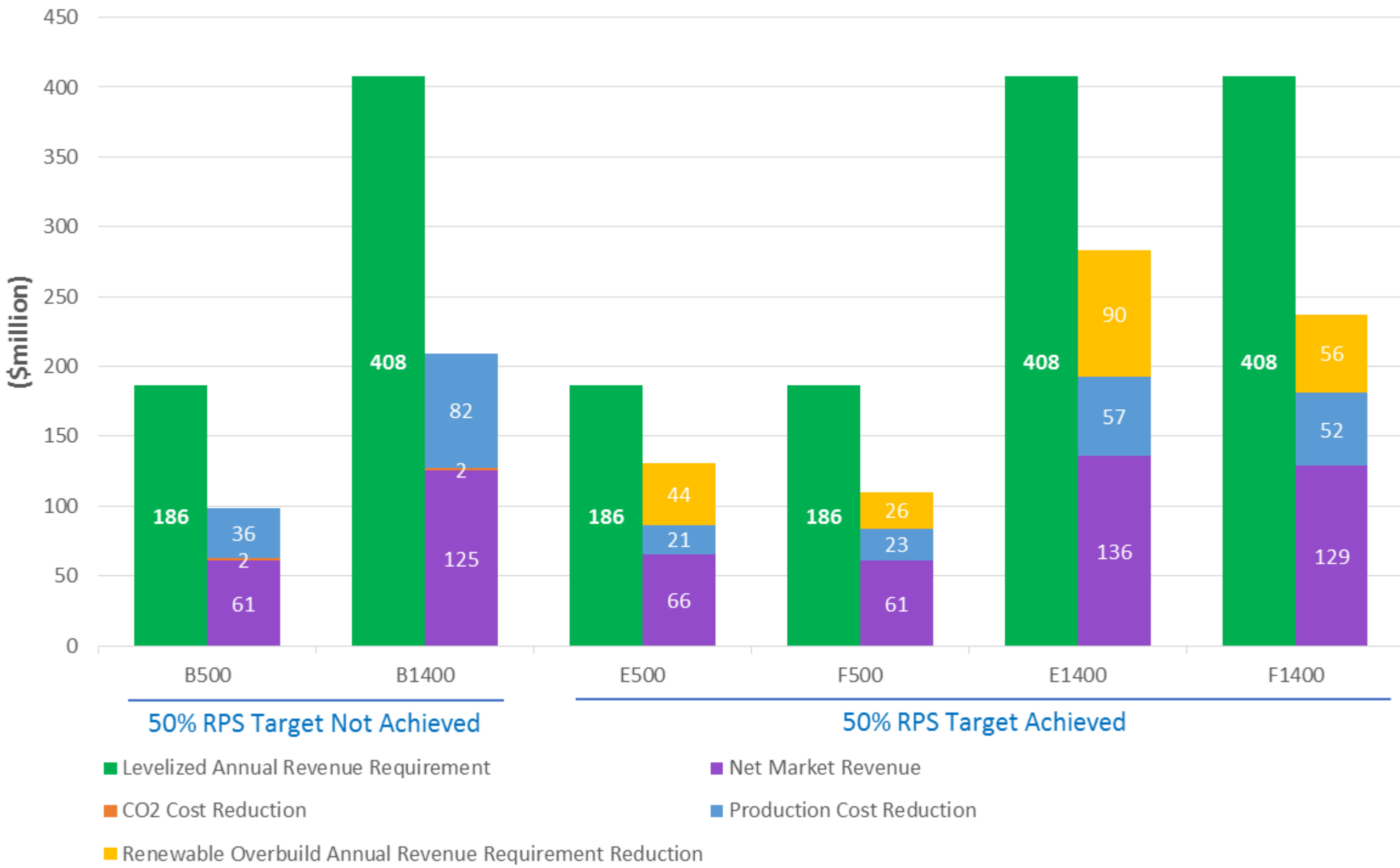
Levelized annual revenue requirements of renewable overbuild and the pumped storage resources



Cost of the 1,400 MW pumped storage is discounted by 20% based on economies of scale assumption

Pumped storage levelized annual revenue requirements, net market revenues and system benefits of 2026

2015 IEPR Mid-AAEE Sensitivity



Net Market Revenue is revenue from energy, reserves and load following minus cost of energy and operation.
System benefits includes reduction of CO_2 emission cost, WECC production cost and renewable overbuild cost

Summary of annual results by case

2015 IEPR Mid-AAEE Sensitivity

	No Pumped Storage			500 MW Pumped Storage			1,400 MW Pumped Storage		
Case	**A**	**C**	**D**	**B500**	**E500**	**F500**	**B1400**	**E1400**	**F1400**
Renewable Curtailment (GWh)	2,365	3,062	2,555	2,000	2,508	2,144	1,601	1,921	1,692
Curtailment Frequency (hours)	708	849	756	635	740	672	505	587	536
CA CO2 Emission (MM-ton)	52.5	51.6	51.7	52.5	51.7	51.7	52.4	51.8	51.8
CA CO2 Emission ($million)	1,187	1,166	1,167	1,185	1,168	1,169	1,185	1,170	1,171
Production Cost ($million)									
WECC	15,619	15,538	15,525	15,583	15,517	15,502	15,537	15,481	15,473
CA	3,899	3,857	3,848	3,846	3,815	3,803	3,770	3,740	3,733
Renewable Overbuild and Pumped Storage Capacity (MW)									
Solar		1,072			878			672	
Wind			726			610			481
Pumped Storage				0	0	0	1,400	1,400	1,400
Levelized Annual Revenue Requirement of Renewable Overbuild and Pumped Storage ($million/year)									
Solar		242			198			152	
Wind			166			140			110
Pumped Storage				186	186	186	408	408	408
Sum		*242*	*166*	*186*	*384*	*326*	*408*	*560*	*518*
Pumped Storage Net Market Revenue ($million)				61	66	61	125	136	129
System Benefits by the Pumped Storage Resource ($million)				36	65	49	82	147	108

Notes:
1. Renewable curtailment price is assumed as -$15/MWh for the first 200 GWh and -$25/MWh for additional 12,400 GWh.
2. CA CO2 Emission includes the CO2 emission from net import.
3. CO2 cost is $22.59/M-ton.
4. Production cost includes start-up, fuel and VOM cost, but not CO2 cost.
5. Net Market Revenue is revenue from energy, reserves and load following minus cost of energy and operation.

Default Scenario with a 4-tier curtailment prices

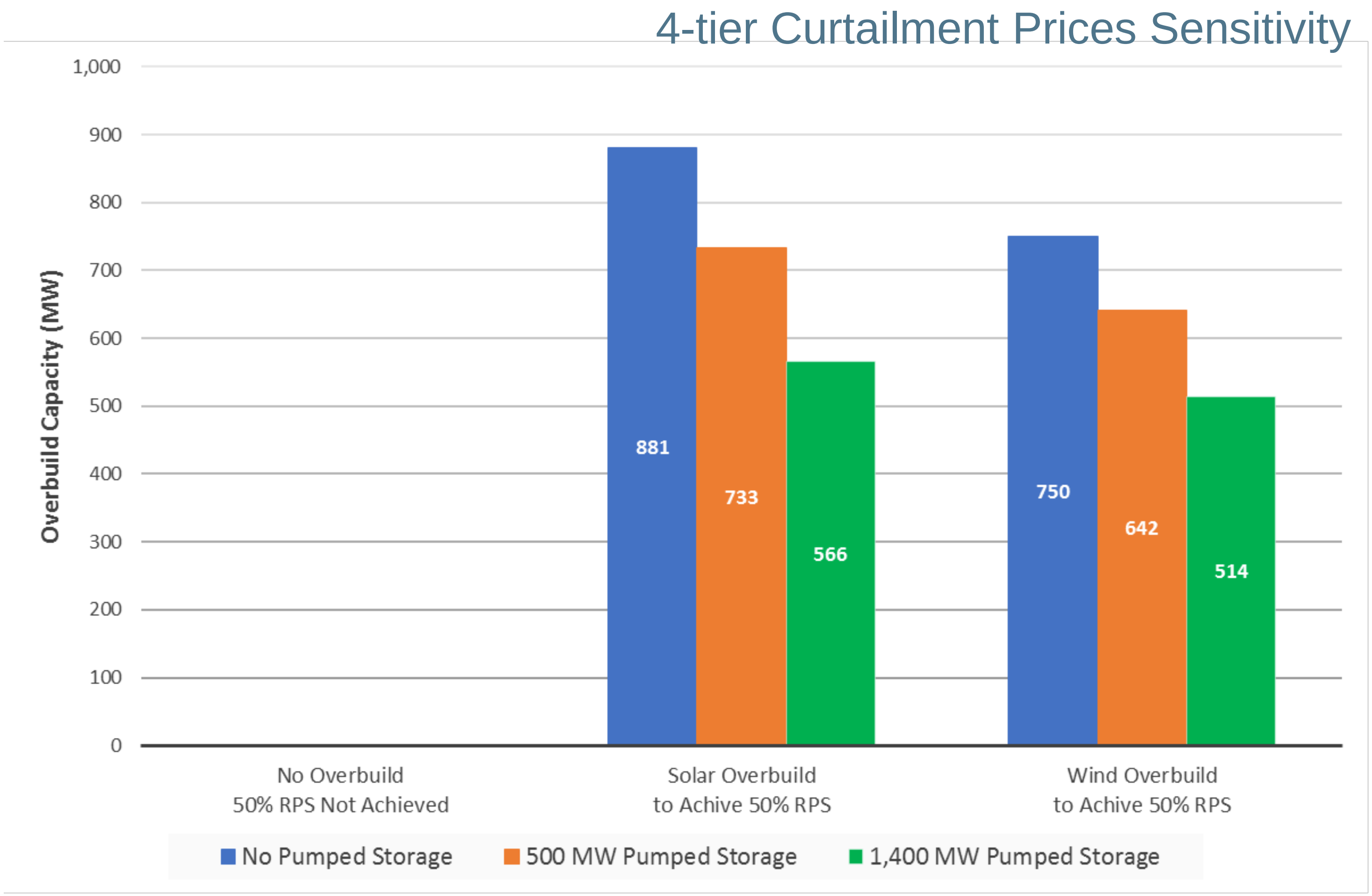
The case of non-dispatchable CHP

- Based on the updated Default Scenario, which assumes that the fist 200 GWh renewable will be curtailed at -$15/MWh, additional 12,400 GWh renewable will be curtailed at -$25/MWh, the rest at -$300/MWh

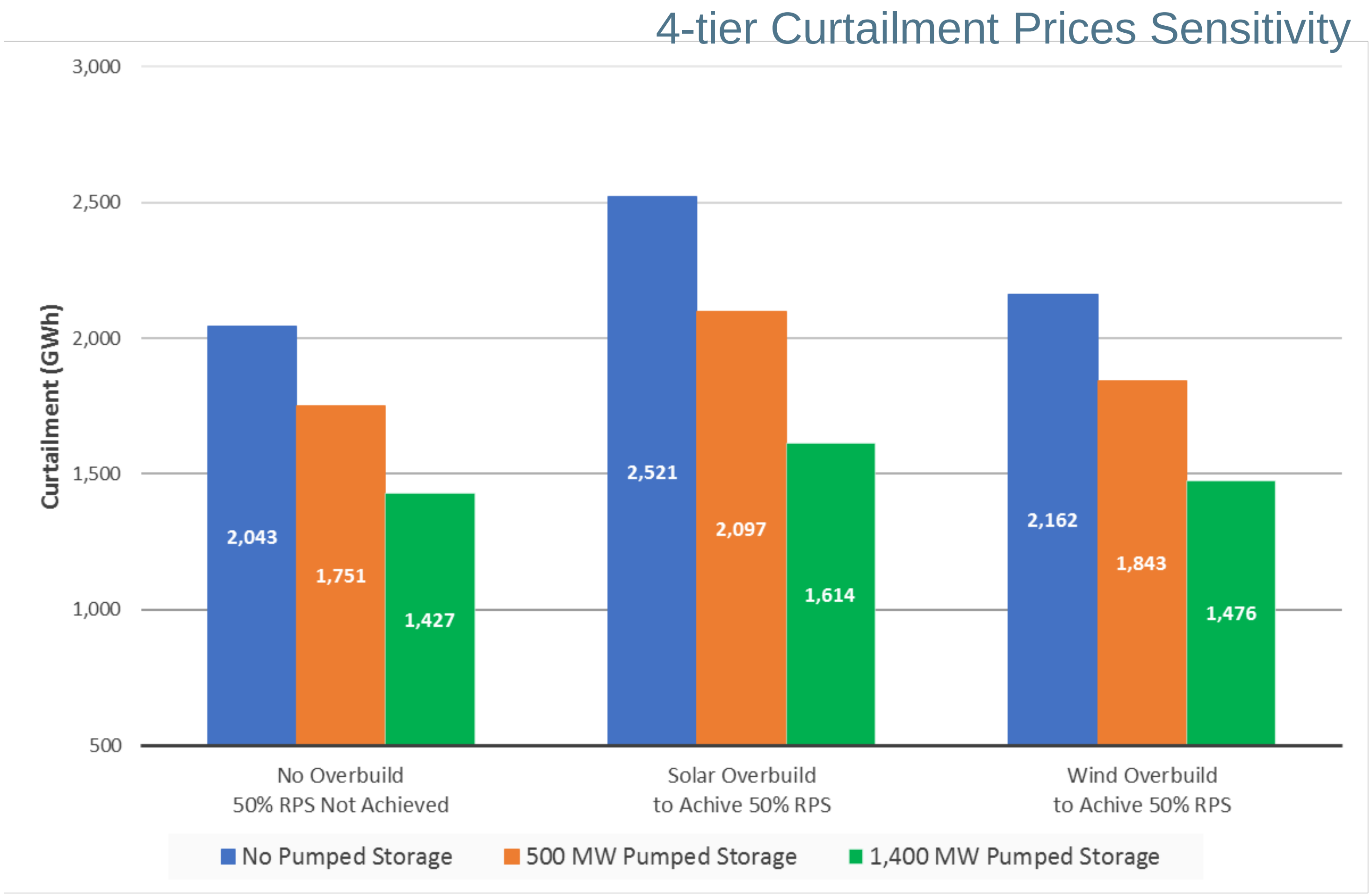
- In this case the curtailment prices in 4 tiers in the table below are used

	Tier 1	Tier 2	Tier 3	Tier 4
Curtailment Price ($/MWh)	-15	-25	-50	-150
Max Curtailment (GWh)	200	1,300	500	All the rest

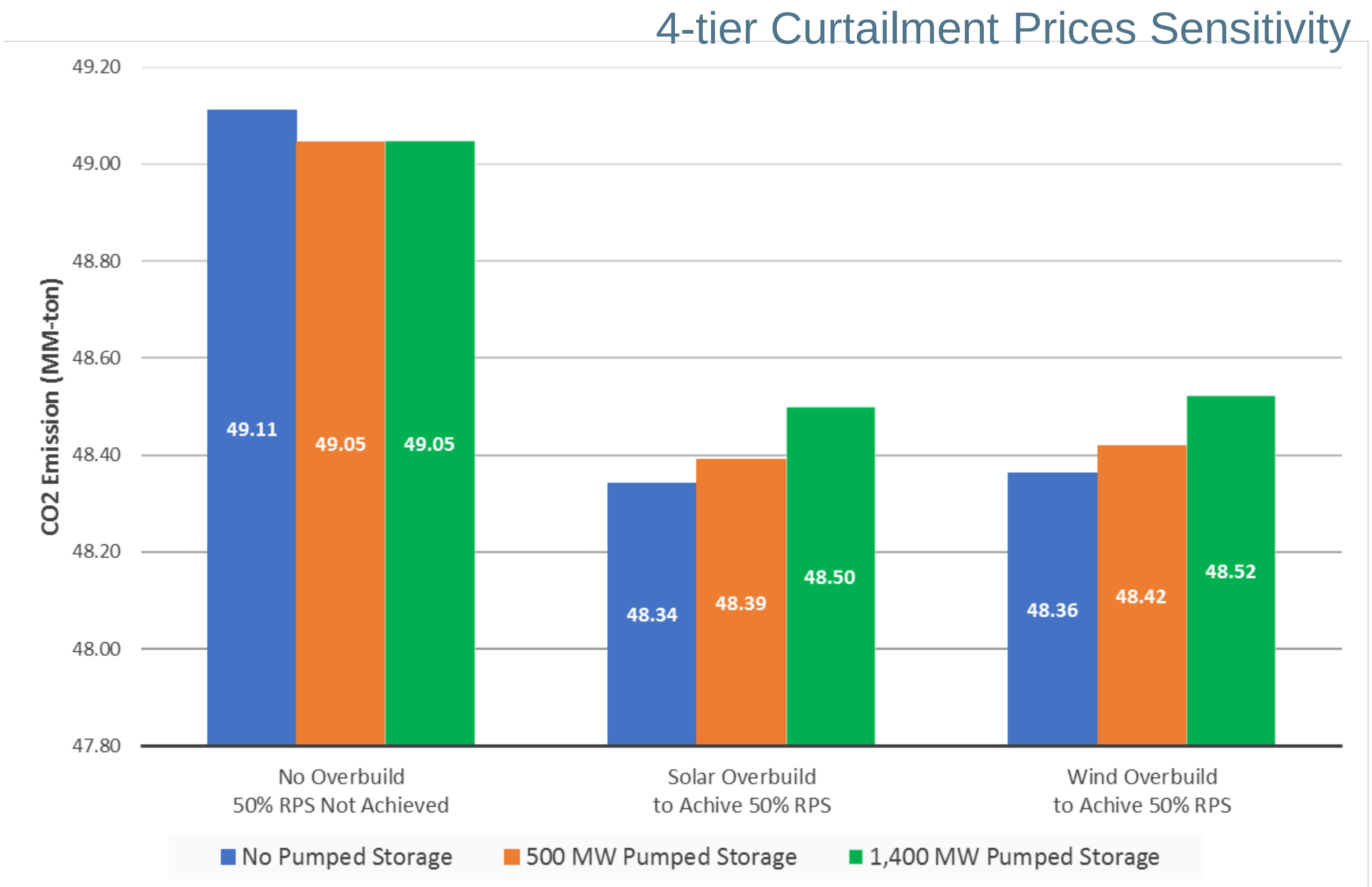
Capacity of renewable overbuild to achieve the 50% RPS target



California renewable generation curtailment

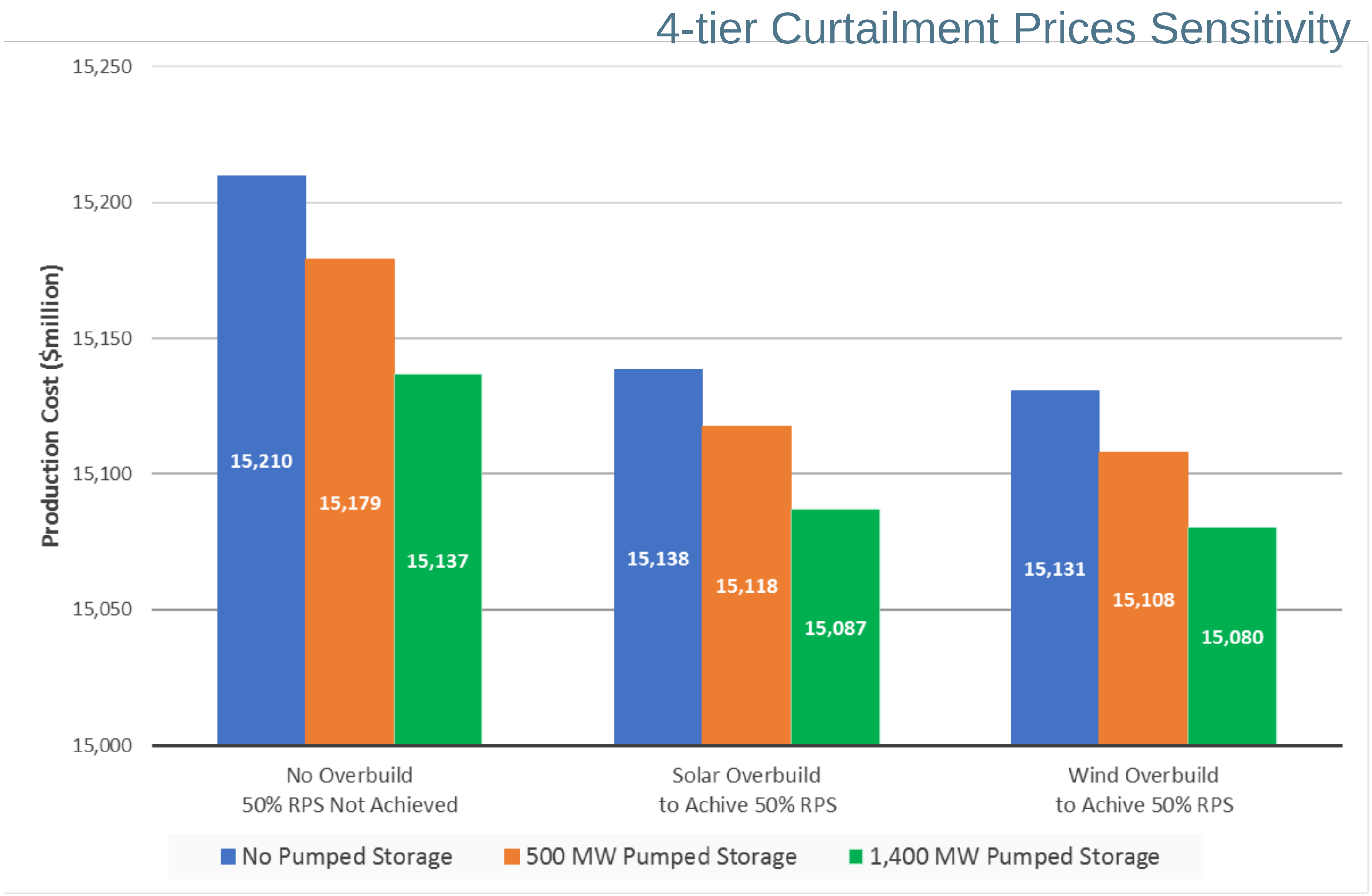


California CO2 emission (50% RPS)



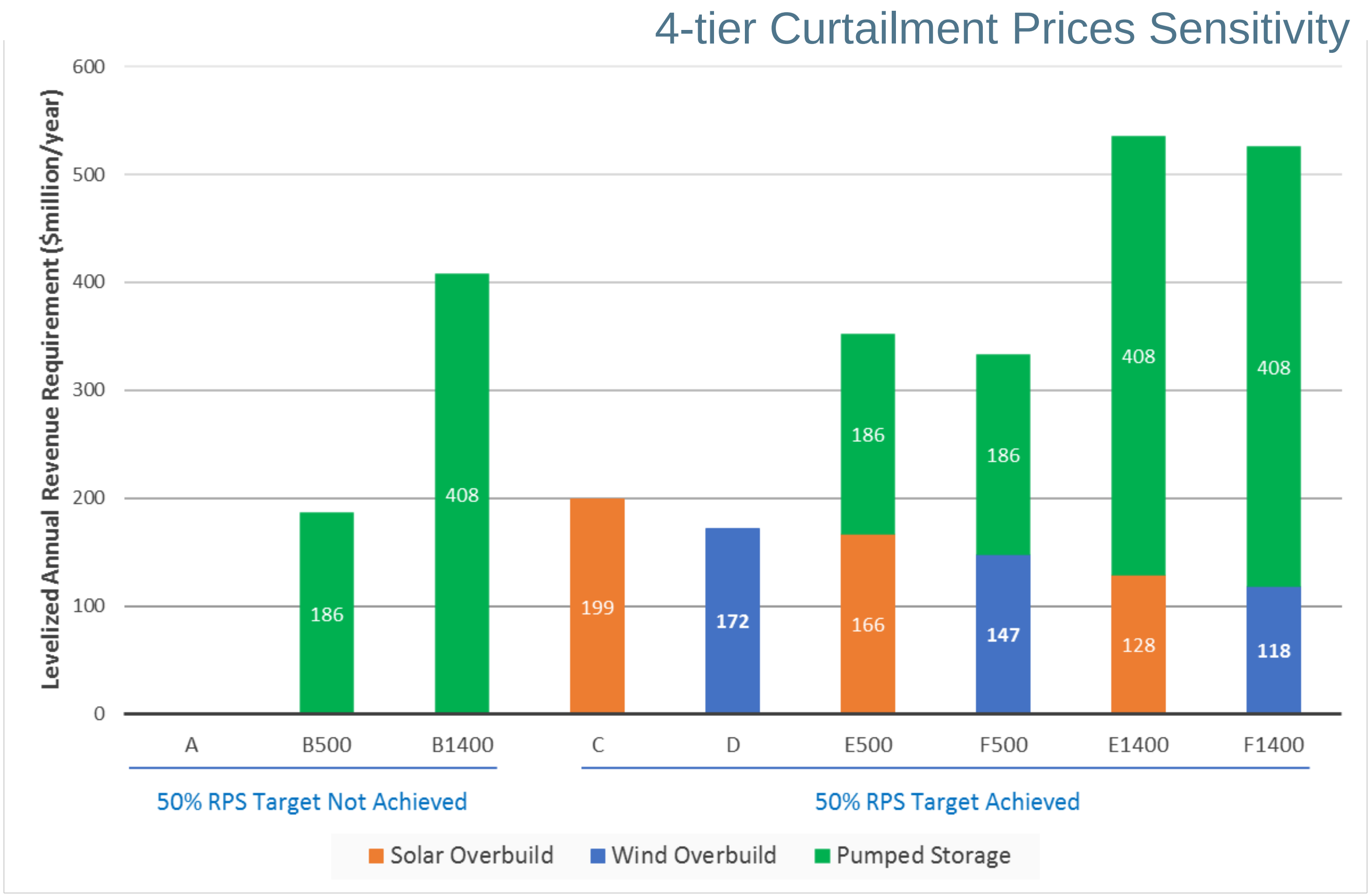
CA CO2 Emission includes the CO2 emission from net import

WECC annual production cost



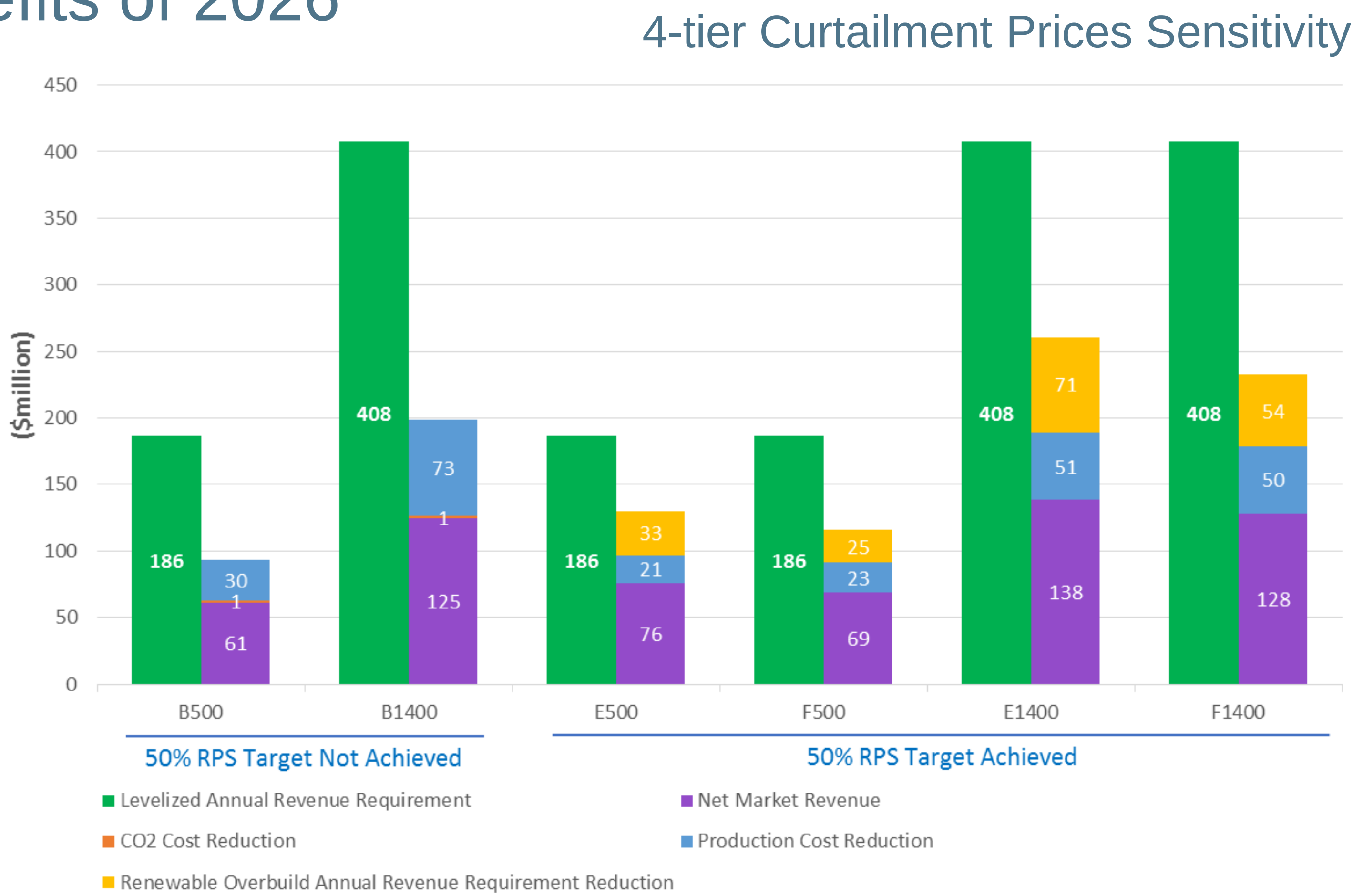
Production cost includes start-up, fuel and VOM cost, but not CO2 cost.

Levelized annual revenue requirements of renewable overbuild and the pumped storage resources



Cost of the 1,400 MW pumped storage is discounted by 20% based on economies of scale assumption

Pumped storage levelized annual revenue requirements, net market revenues and system benefits of 2026



Net Market Revenue is revenue from energy, reserves and load following minus cost of energy and operation.
System benefits includes reduction of CO2 emission cost, WECC production cost and renewable overbuild cost

Summary of annual results by case

4-tier Curtailment Prices Sensitivity

	No Pumped Storage			500 MW Pumped Storage			1,400 MW Pumped Storage		
Case	A	C	D	B500	E500	F500	B1400	E1400	F1400
Renewable Curtailment (GWh)	2,043	2,521	2,162	1,751	2,097	1,843	1,427	1,614	1,476
Curtailment Frequency (hours)	659	783	707	588	683	608	476	539	487
CA CO2 Emission (MM-ton)	49.1	48.3	48.4	49.0	48.4	48.4	49.0	48.5	48.5
CA CO2 Emission ($million)	1,109	1,092	1,093	1,108	1,093	1,094	1,108	1,096	1,096
Production Cost ($million)									
WECC	15,210	15,138	15,131	15,179	15,118	15,108	15,137	15,087	15,080
CA	3,578	3,534	3,532	3,532	3,498	3,489	3,464	3,438	3,429
Renewable Overbuild and Pumped Storage Capacity (MW)									
Solar		881			733			566	
Wind			750			642			514
Pumped Storage				500	500	500	1,400	1,400	1,400
Levelized Annual Revenue Requirement of Renewable Overbuild and Pumped Storage ($million/year)									
Solar		199			166			128	
Wind			172			147			118
Pumped Storage				186	186	186	408	408	408
Sum		*199*	*172*	*186*	*352*	*333*	*408*	*536*	*526*
Pumped Storage Net Market Revenue ($million)				61	76	69	125	138	128
System Benefits by the Pumped Storage Resource ($million)				30	54	48	73	122	104

Notes:

1. Renewable curtailment price is assumed as -$15/MWh for the first 200 GWh and -$25/MWh for additional 12,400 GWh.
2. CA CO2 Emission includes the CO2 emission from net import.
3. CO2 cost is $22.59/M-ton.
4. Production cost includes start-up, fuel and VOM cost, but not CO2 cost.
5. Net Market Revenue is revenue from energy, reserves and load following minus cost of energy and operation.

Risks of Early Economic Retirement of Gas-Fired Generation

- Sensitivities of the 2016-2017 TPP Studies

Shucheng Liu
Principal, Market Development

2017-2018 Transmission Planning Process Stakeholder Meeting
September 21, 2017

2016-2017 Study Scope

- Identify the incremental path flow impacts (congestion from PCM) of the retirement scenarios on California transfer paths.
- Identify high level potential path flow impacts on the California transfer paths and the associated RAS (IRAS) using power flow analysis.
- Identify potential system level impacts on ancillary services and flexibility requirements.

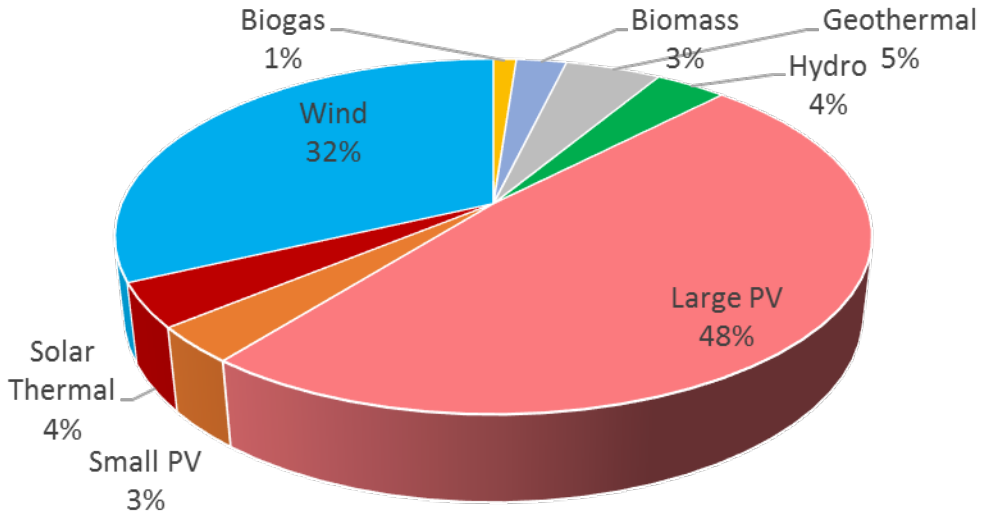
Load forecast and adjustments of the 2016 LTPP Default Scenario

Peak Load (MW)	1-in-2 Peak MW, No AAEE	SB350 AAEE Peak Impact	IEPR BTM PV Peak Impact	Pumping Load Peak Impact	Non-coincident Peak (MW)
IID	1,137	0	40	0	1,177
LDWP	7,022	-1,031	213	0	6,205
PG&E_BAY	8,945	-1,425	694	0	8,214
PG&E_VLY	13,120	-1,850	1,124	-560	11,835
SCE	23,313	-3,786	1,739	-411	20,855
SDGE	4,705	-817	504	0	4,393
SMUD	5,044	-511	120	-142	4,511
TIDC	723	0	70	0	793
CAISO	**50,083**	**-7,877**	**4,061**	**-971**	**45,297**
CA	**64,009**	**-9,418**	**4,504**	**-1,113**	**57,982**

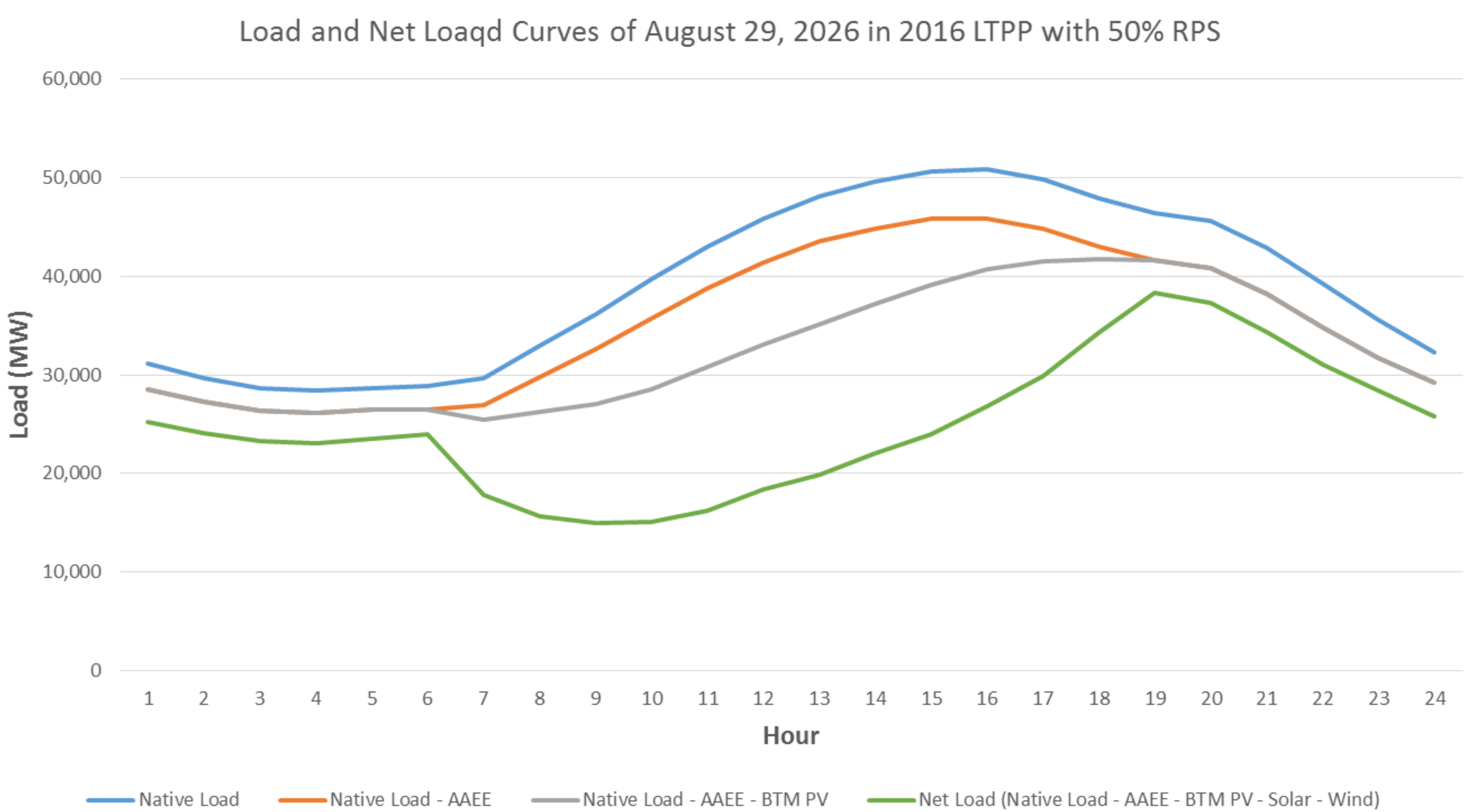
- Load forecast is from 2015 IEPR, which is lower than that of 2014 IEPR
- SB350 AAEE has a 7,601 MW maximum value
- BTM PV has 12,238 MW installed capacity

Assumptions and results of the Default Scenario from 2016-2017 TPP

The 50% RPS portfolio – solar is the dominant resource



Net load on the annual peak net load day – illustration of peak shifting due to solar generation



The study simulated six retirement cases

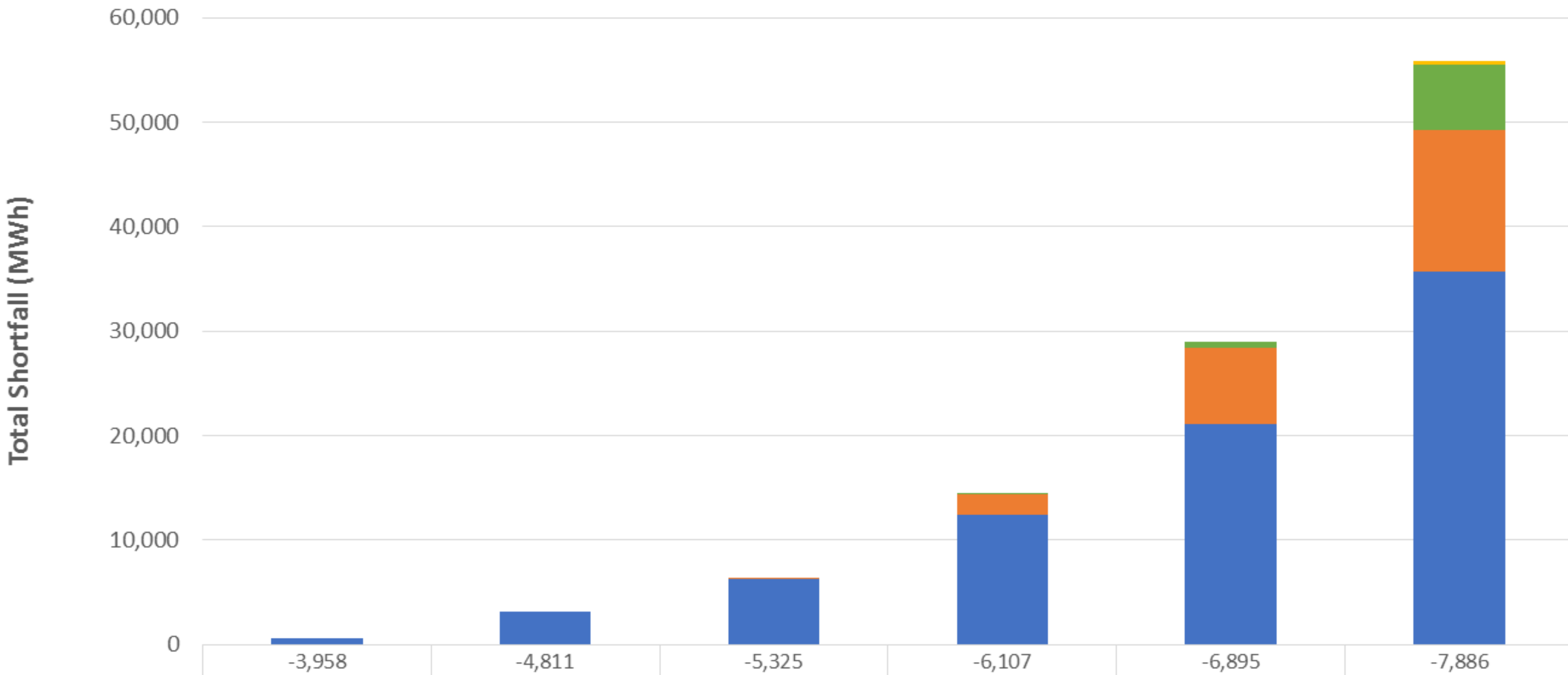
Default Scenario from 2016-2017 TPP

Retirement by Technology (MW)	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6
CCGT	-3,739	-4,325	-4,325	-5,107	-5,107	-5,107
CHP	-219	-286	-751	-751	-840	-1,138
GT	0	-200	-250	-250	-939	-1,632
ST	0	0	0	0	-10	-10
Total	**-3,958**	**-4,811**	**-5,325**	**-6,107**	**-6,895**	**-7,886**

- The candidates for retirement assessment
  - Were selected through a screening using the transmission model
  - Met local capacity requirements and transmission constraints

Total load-following and reserve shortfalls by case

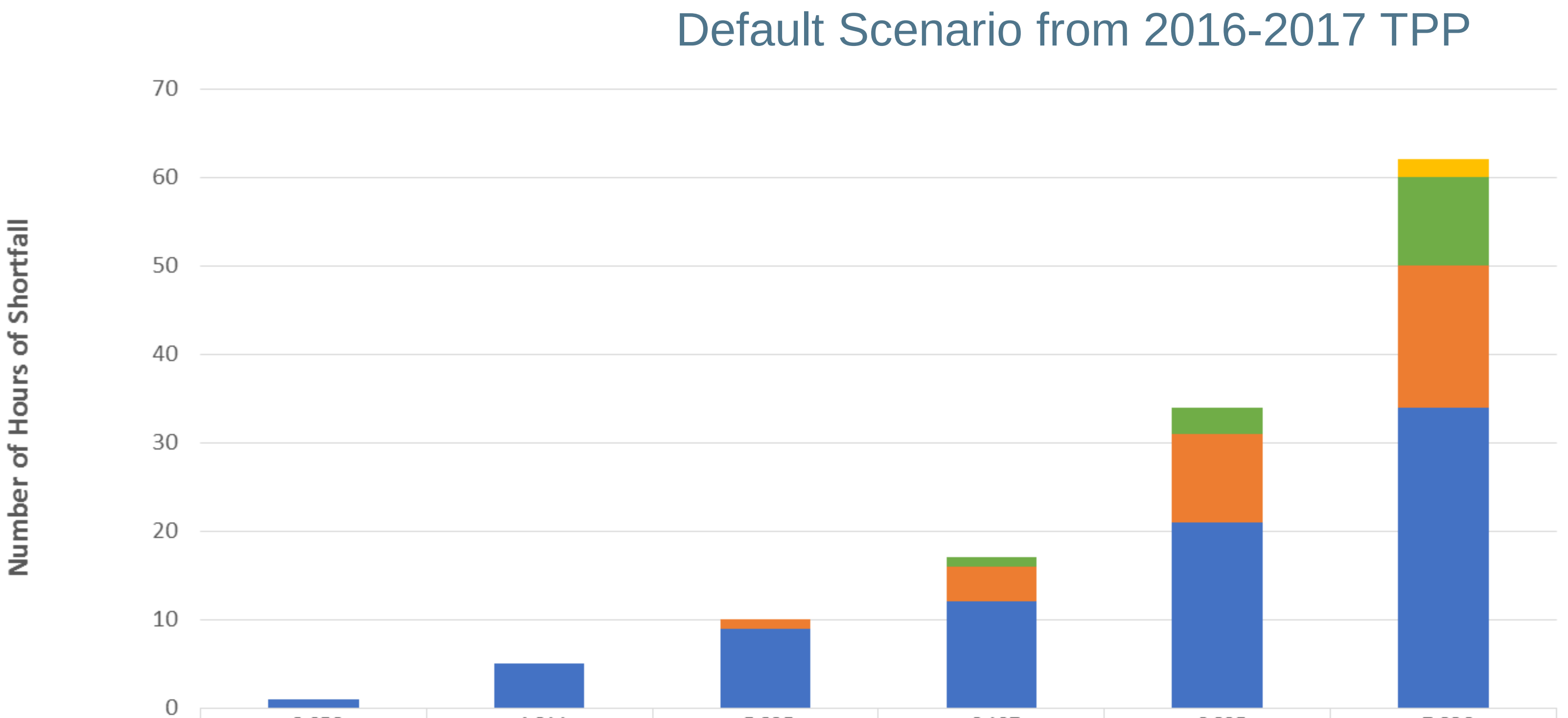
Default Scenario from 2016-2017 TPP



	-3,958	-4,811	-5,325	-6,107	-6,895	-7,886
RegulationUp						303
Spining Reserve				12	625	6,208
NonSpin Reserve			107	1,890	7,336	13,545
LoadFollowingUp	636	3,181	6,268	12,436	21,047	35,743

Case (MW retirement)

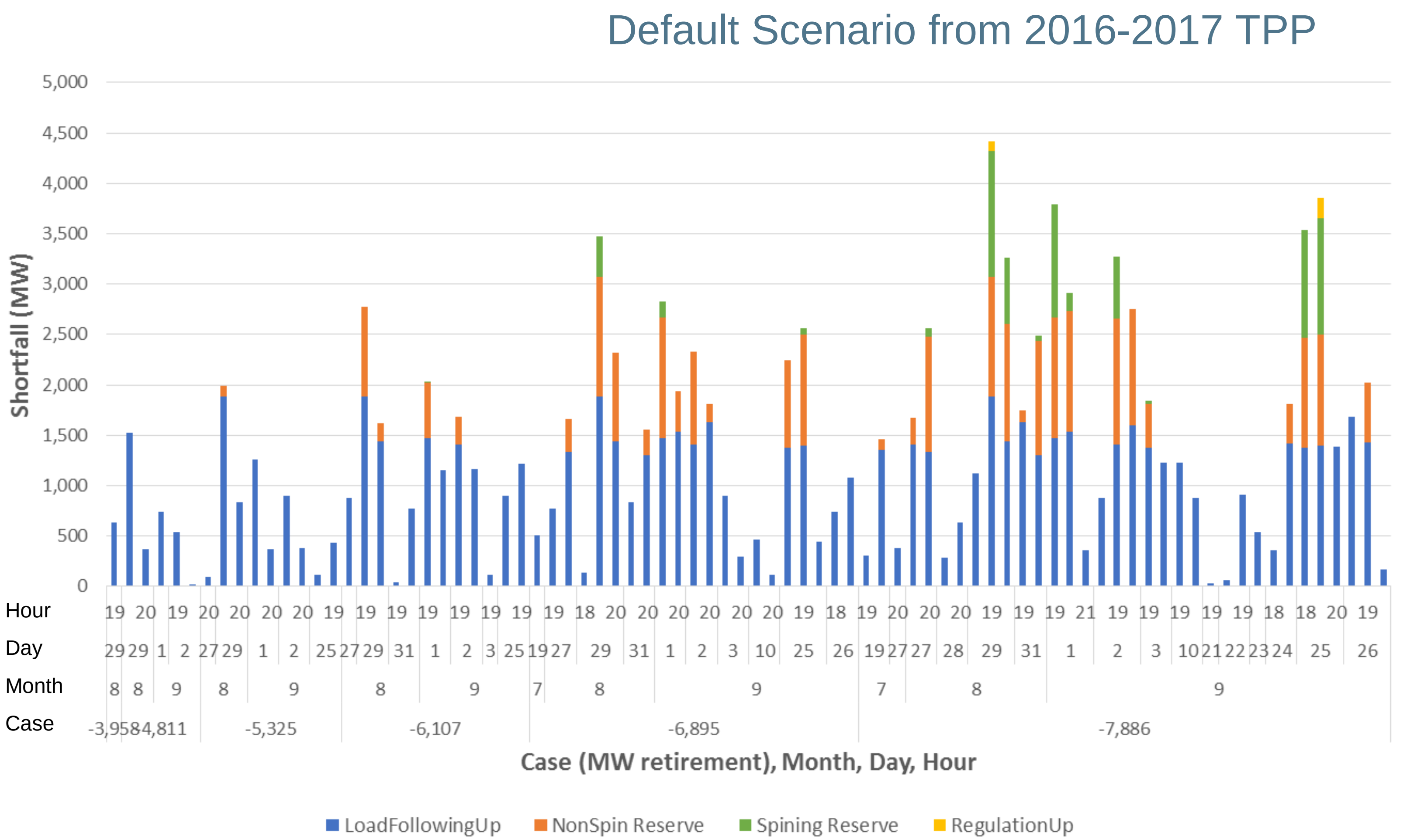
Total number of hours with load-following and reserve shortfalls by case



Case (MW retirement)	-3,958	-4,811	-5,325	-6,107	-6,895	-7,886
RegulationUp						2
Spining Reserve				1	3	10
NonSpin Reserve			1	4	10	16
LoadFollowingUp	1	5	9	12	21	34

Case (MW retirement)

Hourly load-following and reserve shortfalls by case



Summary of Findings

- Unlimited renewable curtailment masks the need for flexible capacity during downward ramping in the morning and upward ramping in the afternoon
- The shortfalls in load-following and reserves reflect the insufficiencies of capacity
- Capacity insufficiencies occur in early evening after sunset, which is the new peak (net) load time
- Capacity sufficiency issues start to emerge between 4,000 to 6,000 MW of retirement, considering some uncertainties in forecasts.

New Sensitivities

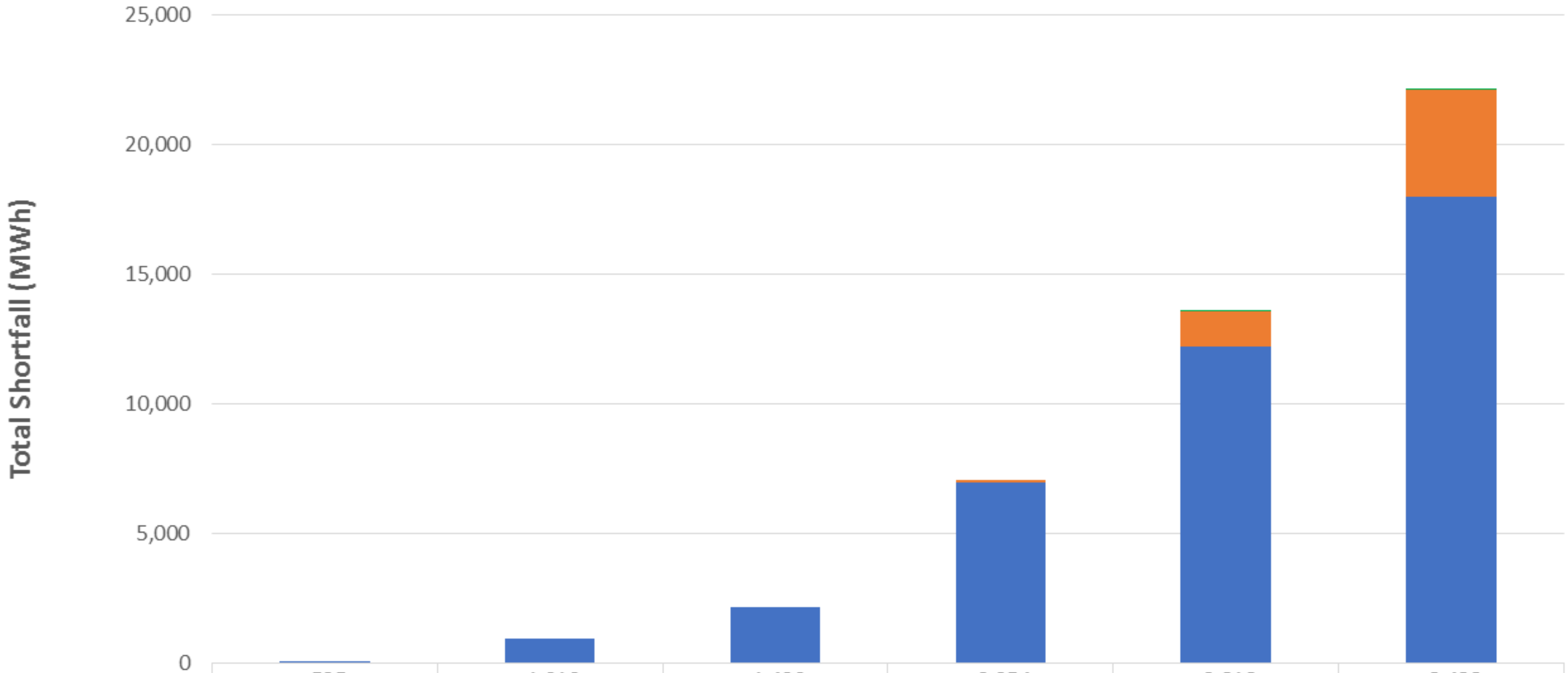
– Default Scenario with 2015 IEPR Mid-AAEE

Assumptions for this sensitivity case

- This is the sensitivity of the Base Case
  - Base Case has the SB350 AAEE assumption that the 2015 IEPR Mid-AAEE forecast will be doubled by 2030
  - This sensitivity replaces that SB350 AAEE assumption with the 2015 IEPR Mid-AAEE forecast
  - Aligned with other 2016-2017 plan results

Total load-following and reserve shortfalls by case

2015 IEPR Mid-AAEE Sensitivity



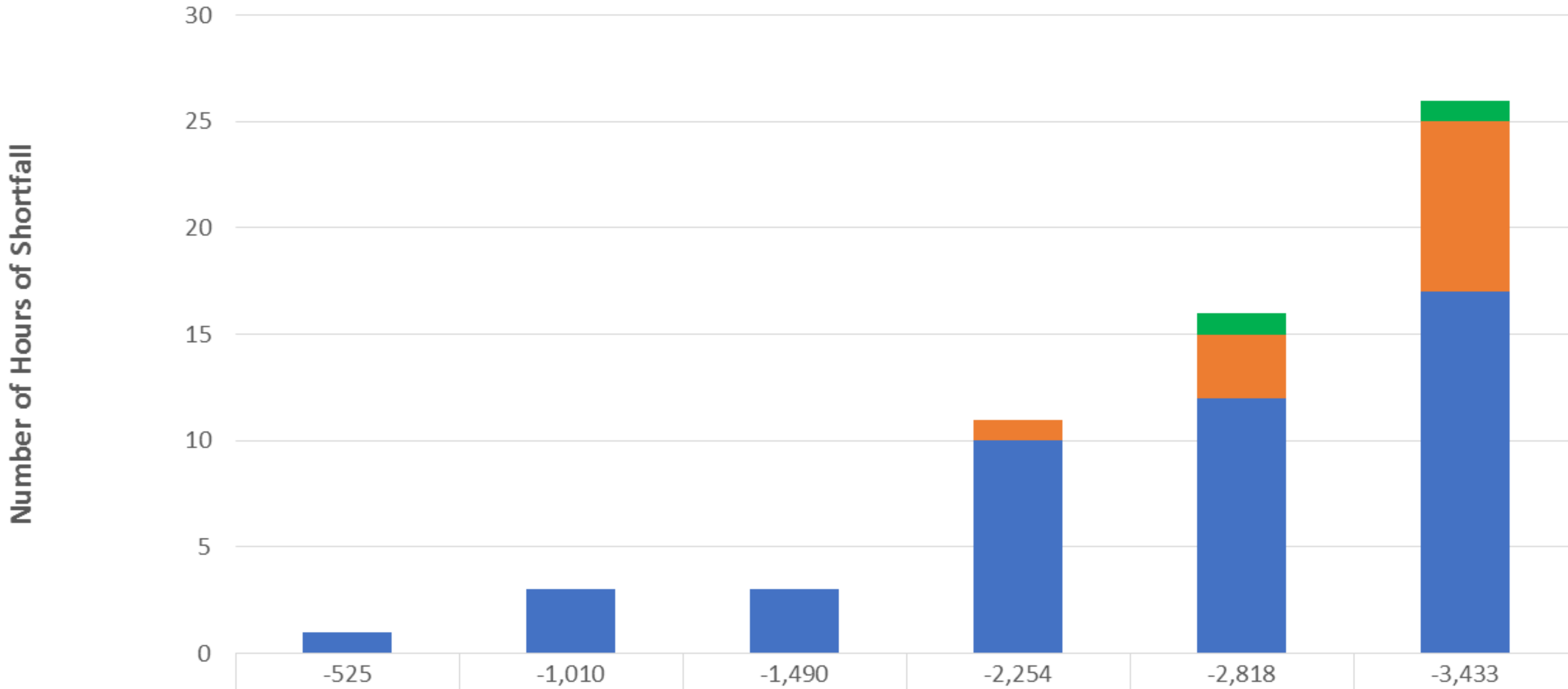
	-525	-1,010	-1,490	-2,254	-2,818	-3,433
Spining Reserve					17	3
NonSpin Reserve				81	1,342	4,107
LoadFollowingUp	67	946	2,155	6,971	12,228	18,006

Case (MW Retirement)

California ISO

Total number of hours with load-following and reserve shortfalls by case

2015 IEPR Mid-AAEE Sensitivity

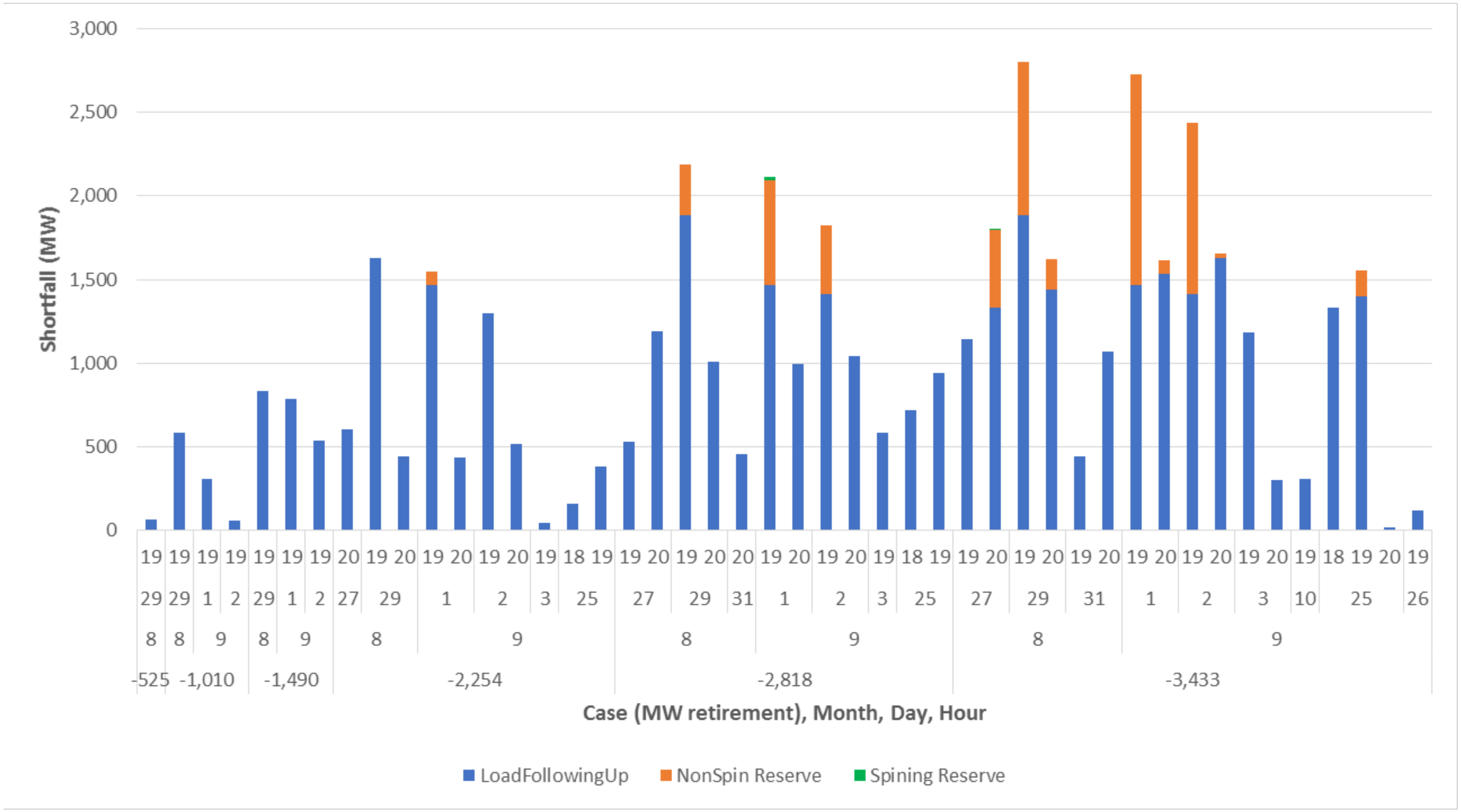


	-525	-1,010	-1,490	-2,254	-2,818	-3,433
Spining Reserve					1	1
NonSpin Reserve				1	3	8
LoadFollowingUp	1	3	3	10	12	17

Case (MW Retirement)

Hourly load-following and reserve shortfalls by case

2015 IEPR Mid-AAEE Sensitivity



Summary of Findings

- Capacity sufficiency issues start to emerge between 1,000 to 2,800 MW of retirement, considering some uncertainties in forecasts.

New Sensitivities

– Default Scenario with 2015 IEPR Mid-AAEE and 2,000 MW CCGT or GT Retirement

Assumptions for this sensitivity case

- This is a special case based on the Default Scenario with 2015 IEPR Mid-AAEE sensitivity case
  - To evaluate the effects of retirement of 2,000 MW CCGT or GT, or the combination of the two types of resources

Summary of results of the Default Scenario with 2015 IEPR Mid-AAEE with 2,000 MW CCGT or GT retirement

California-Wide	Base Case	Case 1	Case 2	Case 3		Change - Base to Case 1	Change - Base to Case 2	Change - Base to Case 3
Capacity Retirement (MW)								
- CCGT		2,035		1,010		2,035		1,010
- GT			2,031	1,017			2,031	1,017
- Total Retirement		2,035	2,031	2,027		2,035	2,031	2,027
Total Load (GWh)	305,891	305,876	305,874	305,822		-14	-17	-69
Generation (GWh)	243,749	241,951	243,922	243,017		-1,798	173	-732
Net Import (GWh)	62,142	63,925	61,952	62,805		1,783	-190	664
Renewable Curtailment								
- Energy (GWh)	2,365	2,370	2,395	2,371		5.4	29.7	6.4
- Number of Hours	708	715	736	725		7	28	17
Production Cost ($million)								
- WECC	15,619	15,634	15,653	15,645		15	34	26
- CA	3,899	3,844	3,938	3,909		-55	39	10
CO2 Emission (million M-Ton)								
- WECC	314.95	315.46	315.15	315.29		0.51	0.20	0.35
- CA (including net import)	52.54	52.91	52.71	52.80		0.37	0.17	0.26
CA CO2 Emission Cost ($million)	1,187	1,195	1,191	1,193		8.3	3.8	5.8
Capacity Shortfall								
- Shortfall Volume (MWh)	0	4,880	4,816	4,803		4,880	4,816	4,803
- Number of Hours	0	8	8	7		8	8	7

Summary of Findings

- The retirement of about 2,000 MW flexible resources has caused some system resource shortfalls

Special Study Frequency Response Assessment-Generation Modeling – Update

Irina Green

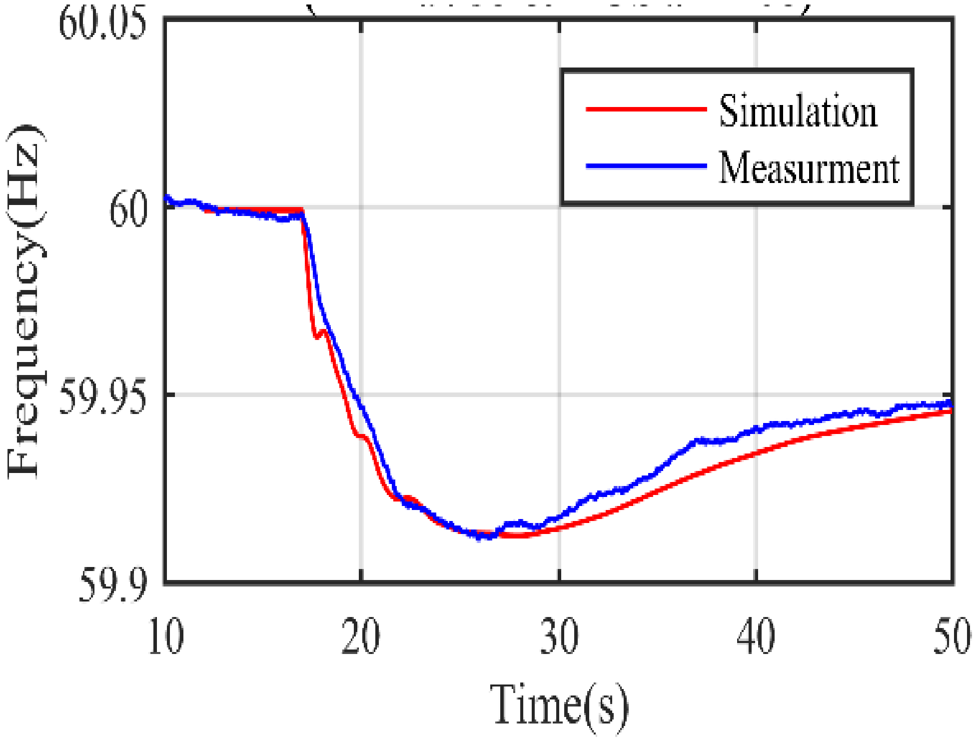
Senior Advisor, Regional Transmission

2017-2018 Transmission Planning Process Stakeholder Meeting

September 21-22, 2017

Frequency Response Studies

- Frequency response studies performed in the previous Transmission Plans showed optimistic results
- Actual measurements of the generators' output were lower that the generators' output in the simulations
- Therefore models update and validation is needed
- After improvement of models, more frequency studies will be performed



Update of Generator Models

- The ISO reviewed, and identified issues with dynamic stability models for multiple units
- Issues
  - Missing models
  - Suspicious models
  - Models with generic parameters
  - Models no longer approved by WECC
- Currently working with the PTOs to get results from generator testing and improve the models
- Challenges:
  - Challenges in getting fully validated models from generation owners
  - Difference between NERC Standards and WECC Policy on generator testing

Standards on Generator Testing

- NERC dynamic data related compliance (MOD-26 and MOD-27) applies to the following to Western Interconnection:
  - Individual generating unit greater than 75 MVA (gross nameplate rating).
  - Individual generating plant consisting of multiple generating units that are directly connected at a common BES bus with total generation greater than 75 MVA (gross aggregate nameplate rating).
- WECC Policy applies to:
  - Generating facilities connected to the Western Electricity Coordinating Council (WECC) transmission grid at 60 kV or higher voltage (both new and existing, synchronous and non-synchronous) with single unit capacity of 10 MVA and larger, or facilities with aggregate capacity of 20 MVA and larger.

Next Steps

Kim Perez
Stakeholder Engagement and Policy Specialist

2017-2018 Transmission Planning Process Stakeholder Meeting
September 21-22, 2017

2017-2018 Transmission Planning Process
Next Steps

- Comments due October 6
  - regionaltransmission@caiso.com
- Request window closes October 15
  - requestwindow@caiso.com
- ISO recommended projects:
  - For management approval of reliability projects less than $50 million will be presented at November stakeholder session
  - For Board of Governor approval of reliability projects over $50 will be included in draft plan to be issued for stakeholder comments by January 31, 2018