California ISO

Introduction and Agenda

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2021-2022 Transmission Planning Process Stakeholder Call

July 27, 2021

Reminders

- Stakeholder calls and meetings related to Transmission Planning are not recorded.
  - Given the expectation that documentation from these calls will be referred to in subsequent regulatory proceedings, we address written questions through written comments, and enable more informal dialogue at the call itself.
  - Minutes are not generated from these calls, however, written responses are provided to all submitted comments.
- To ask a question, press #2 on your telephone keypad. Please state your name and affiliation first.
- Calls are structured to stimulate an honest dialogue and engage different perspectives.
- Please keep comments professional and respectful.

Agenda

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Updated Transmission Capability Estimates for Use in CPUC's Resource Planning Process

Nebiyu Yimer
Senior Advisor Regional Transmission Engineer

2021-2022 Transmission Planning Process Stakeholder Meeting
July 27, 2021

Contents

- Background
- Recap of previous transmission capability estimate
- The updated transmission capability estimate
- Intended implementation in CPUC's resource planning process

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Background

- As part of its IRP process, the CPUC develops resource plans to meet the state's renewable policy and resource adequacy requirements.
- The CPUC currently uses the RESOLVE resource optimization model for developing resource portfolios.
- The portfolios are comprised of:
    - FCDS resources, which count towards resource adequacy, and
    - EODS resources, which contribute to meeting renewable energy targets but do not count towards resource adequacy.
- Transmission capability information supplied by the ISO is one of the key inputs to the resource optimization and busbar mapping process and indicates if transmission upgrades would be triggered by the locations and amounts of FCDS and EODS resources selected.

Background - cont'd

- This presentation provides stakeholders an overview of the updated transmission capability estimate whitepaper the ISO developed and provided to the CPUC.
- As the name suggests, transmission capability estimates are just estimates. They are developed primarily based on the location, mix and size of resources in the ISO generation interconnection queue and certain other assumptions described later in this presentation.
- The accuracy of these estimates will be impacted depending, among other things, on the deviation of the resource portfolios selected from the commercial interest that these estimates are based on.
- The final determination of the transmission upgrades needed by the resources portfolios is made during the policy-driven assessment the ISO conducts as part of the TPP.

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Recap of previous transmission capability estimate

- The previous transmission capability estimates white paper was released in May 2019 and was primarily used by the CPUC to develop resource portfolios for the 2021-22 TPP and prior planning cycles

- For each transmission zone and sub-zone, the previous transmission capability estimates provided estimated FCDS capabilities for the existing system, FCDS capabilities with conceptual transmission upgrades and EODS capabilities for the existing system along with the capital cost of the transmission upgrades that increase FCDS capabilities.

- FCDS transmission capability estimates were developed based on the previous ISO deliverability methodology, which is the main reason for the update.

Recap of previous transmission capability estimate - cont'd

- EODS transmission capability was generally developed by adding to the FCDS estimate the amount of gas-fired generation and imports behind the constraint that were assumed to be displaced by the new renewable resources due to their higher marginal cost.
- Both the FCDS and EODS estimates were expressed based on installed capacity rather than based on the resource-type specific output assumptions used in deliverability studies.
- The estimates were implemented in RESOLVE as constants that did not distinguish deliverable capacity taken up by different types of resources.
- The approach had to change particularly given the significant reduction in output assumptions for solar used in the new deliverability methodology and the inclusion of large amounts of battery storage in recent portfolios.

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Elements of the updated transmission capability estimate

- The updated transmission capability estimate information attempts to provide to the extent possible:
    - FDCS and EODS estimates for the existing system that covers all areas where there is commercial interest even if deliverability constraints are not identified,
    - Conceptual transmission upgrades that are identified to increase deliverability along with estimated cost and time to construct,
    - Incremental FCDS and EODS capability provided by the conceptual transmission upgrades,
    - Constraint boundary diagrams/maps showing BES substations inside each constraint zone (*provided as a separate document on the ISO Market Participant Portal*), and
    - Other information that may be helpful to the CPUC in implementing the estimates in the resource planning process
- The primary source of the information are recent deliverability studies conducted as part of the GIDAP using the current deliverability methodology. TPP studies are used as supplemental sources.

The updated transmission capability estimate - South system

Transmission Constraint	Affected Zones	Condition under which Constraint is Binding	Estimated FCDS Capability Based on On-peak Study Resource Output (MW)**		ADNU & Cost Estimate ($million)		Estimated EODS Capability Based on Off-peak Study Resource Output (MW)**		AOPNU & Cost Estimate ($million)		Wind/Solar Area Designation
			Existing System***	Incremetal due to ADNU	ADNU (Time to Construct)	Cost (Escalated to COD)	Existing System***	Incremetal due to AOPNU	AOPNU (Time to Construct)	Cost (Escalated to COD)	
SCE Northern Study Area Constraints											
South of Magunden Constraint	Non-CREZ – Big Creek	On-peak	670	840	Magunden 500kV upgrade (105 months)	$1,197	1,024*	N/A	N/A	N/A	Solar
Antelope – Vincent Constraint	Tehachapi, Non-CREZ – Big Creek	On-peak	4,040	2,700	Antelope - Vincent 500kV line rating increas	$15	5,171*	N/A	N/A	N/A	Solar
Windhub 500/230 kV Transformer Constraint	Tehachapi	On-peak, Off-peak	3,080	1,000	New 500/230kV substation connecting to Windhub 230kV and Vincent 500 kV (108 months)	$1,126	2,070	1,000	New 500/230kV substation connecting to Windhub 230kV and Vincent 500 kV (108 months)	$1,126	Solar
SCE Metro Study Area Constraints											
Laguna Bell – Mesa Constraint	Non-CREZ – Ventura	On-peak	2,708	470	Laguna Bell - Mesa line upgrade (27 months)	$21	2,708*	N/A	N/A	N/A	Solar
SCE Metro Area	Non-CREZ – SCE Metro	None	4,083*	N/A	N/A	-	4,083*	N/A	N/A	N/A	N/A
SCE North of Lugo (NOL) Study Area Constraints											
Lugo 500/230 kV Transformer Constraint	Inyokern_North_Kramer, Victor, Pisgah	On-peak	1,576	980	New Lugo 500/230kV No. 3 transformer (42 months)	$70	1,619*	N/A	N/A	N/A	Solar
Victor-Lugo Constraint	Inyokern_North_Kramer Victor	On-peak	1,156	430	Reconductor Lugo - Victor 230kV lines (27 Months)	$226	1,311*	N/A	N/A	N/A	Solar
Kramer- Victor/Roadway -Victor Constraint	Inyokern_North_Kramer	On-peak, Off-peak	826	430	Loop in Kramer - Victor 115kV line into Roadway and reconductor Kramer to Lugo 230kV lines (81 months)	$108	1,237	480	Loop in Kramer - Victor 115kV line into Roadway and reconductor Kramer to Lugo 230kV lines (81 months)	$108	Solar
SCE Eastern Study Area Constraints											
Serrano – Alberhill – Valley 500 kV Constraint	Riverside_Palm_Springs, Arizona, Imperial	On-peak	5,700	3,648	Devers - Mira Loma - Mesa 500kV line (105 months)	$1,480	11,800*	N/A	N/A	N/A	Solar
Devers – Red Bluff 500 kV Constraint	Riverside_Palm_Springs, Arizona	On-peak, Off-peak	5,400	3,100	New Devers - Red Bluff 500kV No. 3 line (105 months)	$1,022	5,820	1,876	New Devers - Red Bluff 500kV No. 3 line (105 months)	$1,022	Solar
Colorado River 500/230 kV Transformer Constraint	Riverside_Palm_Springs: Colorado River Substation 230 kV	On-peak	1,490	1,000	New Colorado River 500/230kV No. 3 transformer (42 months)	$74	1,739*	1,000	New Colorado River 500/230kV No. 3 transformer (42 months)	$74	Solar
SCE/GLW East of Pisgah (EOP) Study Area Constraints											
Eldorado 500/230 kV Transformer #5 Constraint	Southern_Nevada, 'Eldorado/Mountain Pass (230kV)	On-peak	3,360	400	New Eldorado 500/230 transformer (42 months)	$70	3,360*	N/A	N/A	N/A	Solar
GLW-VEA Area Constraint	Southern_Nevada	On-peak, Off-peak	300	1,000	Pahrump - Sloan Canyon 230kV line rebuild and Innovation - Desert View 230kV line rebuild + other upgrades (60 months)	$175	269	1,110	Pahrump - Sloan Canyon 2nd 230kV line and Innovation - Northwest 2nd 230kV line + other upgrades (60 months)	$200	Solar
Mohave/Eldorado 500 kV	Southern_Nevada	On-peak	1,560*	N/A	N/A	-	1,560*	N/A	N/A	N/A	Solar
SDG&E Study Area Constraints											
East of Miguel Constraint	Arizona, Imperial, Baja, Riverside	On-peak, Off-peak	731	1,412	New Imperial Valley - Serrano 500 kV line (120 months)	$3,680	950	943	New Imperial Valley - Serrano 500 kV line (120 months)	$3,680	Solar
Encina-San Luis Rey Constraint	Arizona, Imperial, Baja, Non-CREZ within San Diego	On-peak	2,901	3,718	New Encina - San Luis Rey 230 kV line (120 months)	$102	3,035*	N/A	N/A	N/A	Solar
Imperial Valley transformer Constraint	Imperial	On-peak	1,959	400	Install a new Imperial Valley 500/230 kV Bank at new substation (105 months)	$214	1,959*	N/A	N/A	N/A	Solar
San Luis Rey-San Onofre Constraint	Arizona, Imperial, Non-CREZ within San Diego	On-peak	1,748	4,269	New San Luis Rey-San Onofre 230 kV line (120 months)	$237	3,281*	N/A	N/A	N/A	Solar
San Diego Internal Constraint	Imperial, Non-CREZ within San Diego	On-peak, Off-peak	968	2,067	Internal San Diego Area reconductoring (18 months)	$89	290	274	Internal San Diego Area reconductoring (18 months)	$89	Solar
Silvergate-Bay Boulevard Constraint	Imperial, Baja, Non-CREZ within San Diego	On-peak	1,202	2,119	Silvergate - Bay Blvd 230kV 3-ohm Series Reactor (72 months)	$31	2,163*	N/A	N/A	N/A	Wind
San Diego Oceanside Constraint	Non-CREZ within San Diego	On-peak	280	301	Oceanside ADNU (60 months)	$133	280*	N/A	N/A	N/A	Solar
Orange County Area	Non-CREZ within San Diego	None	450*	N/A	N/A	-	450*	N/A	N/A	N/A	N/A

The updated transmission capability estimate - North system

Transmission Constraint	Affected Zones	Condition under which Constraint is Binding	Estimated FCDS Capability Based on On-peak Study Resource Output (MW)**		ADNU & Cost Estimate ($million)		Estimated EODS Capability Based on Off-peak Study Resource Output (MW)**		AOPNU & Cost Estimate ($million)		Wind/Solar Area Designation
			Existing System***	Incremetal due to ADNU	ADNU (Time to Construct)	Cost (Escalated to COD)	Existing System***	Incremetal due to AOPNU	AOPNU (Time to Construct)	Cost (Escalated to COD)	
PG&E North of Greater Bay Study Area Constraints											
Rio Oso-SPI-Lincoln 115 kV Line	Rio Oso area within Sacramento River	On-peak	42	54	Rio Oso (74 months)	$18	124*	N/A	N/A	N/A	WInd
Woodland-Davis 115 kV Lines	Davis Area within Sacramento River	On-peak	64	36	Q653-Davis (60 months)	$11	64*	N/A	N/A	N/A	WInd
Cortina -Vaca-Dixon 230kV Line	Sacramento River& Round Mountain	On-peak	454	2,838	Delevan 500kV (144 months)	$3,531	795*	N/A	N/A	N/A	Wind
Humboldt-Trinity 115 kV Line	Humboldt	On-peak	21	57	Humboldt (98 months)	$158	63*	N/A	N/A	N/A	Wind
PG&E Greater Bay Study Area Constraints											
Vierra-Tracy-Kasson 115 kV Line	Kasson Area within Sacramento River	On-peak	149	125	Vierra-Tracy-Kasson 230 kV (62 months)	$15	247*	N/A	N/A	N/A	WInd
Melones-Tulloch 115 kV Line	Melones area within Sacramento River	On-peak	126	46	Melones-Tulloch 230 kV (64 months)	$18	239*	N/A	N/A	N/A	WInd
Contra Costa-Delta Switchyard 230kV Line	Solano & Round Mountain	On-peak	1,523	1,476	Bay Area (CC) (86 months)	$505	1,523*	N/A	N/A	N/A	Wind
PG&E South 500 kV Study Area Constraints											
Gates-Panoche #1 and #2 230kV Lines	Westlands and Carizzo	On-peak, Off-peak	10,830	378	Gates-Panoche #1 and #2 230kV lines (50 months)	$259	10,830*	N/A	Gates-Panoche #1 and #2 230kV lines (50 months)	$259	Solar
PG&E East Kern Study Area Constraints											
Midway – Gates 230kV Line	Kern and Greater Carrizo	On-peak, Off-peak	1,431	3,137	Gates - Arco - Midway 230 kV-Redraw boundary (98 months)	$142	2568*	N/A	Gates - Arco - Midway 230 kV-Redraw boundary (98 months)	$142	Solar
Kern–Lamont-Stockdale 115kV Line	Carrizo	Off-Peak	3*	N/A	N/A	N/A	125	30	Lamont-Stockdale 115kV (74 months)	$84	Solar
PG&E West Kern Study Area Constraints											
Morro Bay-Templeton 230kV Line	Westlands Kern and Carizzo	On-peak, Off-peak	1,708	739	Morro Bay 230 kV (98 months)	$1,248	1903*	N/A	Morro Bay 230 kV (98 months)	$1,248	Solar
PG&E Fresno Study Area Constraints											
Gates 500/230kV Bank #13 Constraint	Westlands, Carrizo and Kern	On-peak, Off-peak	3,151	4,453	Gates TB # 13 ADNU (48 months)	$40	3,279	964	Gates TB # 13 ADNU (48 months)	$40	Solar
Wilson-Storey-Borden #1 & #2 230 kV Lines	Within Westlands	On-peak	113	96	Wilson-Storey-Borden #1 and #2 230kV lines (50months)	$232	816*	N/A	N/A	N/A	Solar
Los Banos 500/230kV TB	Westlands	On-peak	1,127	446	Manining ADNU (72 months)	$370	2,534*	N/A	N/A	N/A	Solar
Tesla-Westley 230kV Line	Los Banos and Central Valley	On-peak	1,098	114	Reconductor Tesla-Westley 230 kV Line (50months)	$90	1,098*	N/A	N/A	N/A	Solar
Moss Landing 500kV	Unconstrained zone	On-peak	1,500*	N/A	None	N/A	1,500*	N/A	N/A	N/A	Solar
Warnerville-Wilson 230kV	Westlands	Off-Peak	272*	N/A	N/A	N/A	737	364	Warnerville-Wilson 230kV (86 months)	$36	Solar
Moss Landing-Las Aguilas 230kV	Los Banos and Central Valley	Off-Peak	316*	N/A	N/A	N/A	-	1,308	Moss Landing-Las Aguilas 230kV (98 months	$48	Solar
Las Aguillas-Panoche #1 and #2 230kV	Los Banos and Central Valley	Off-Peak	334*	N/A	N/A	N/A	516	939	Las Aguillas sw sta-Panoche #1 and #2 230k	$317	Solar
Moss Landing-Los Banos 230kV	Los Banos and Central Valley	Off-Peak	1,611*	N/A	N/A	N/A	3,102	1,822	Moss Landing-Los Banos 230kV (98 months)	$68	Solar
Los Bano-Gates #1 500kV line	Westlands/Los Banos	Off-Peak	1,265*	N/A	N/A	N/A	2,595	2,076	Los Banos-Gates #1 500kV line (98 months)	$640	Solar

Explanation of the updated information

1. Transmission constraint

- Unlike the previous version, the updated transmission capability estimates are organized by deliverability constraint rather than by zone
- The constraints are primarily identified in GIDAP studies in accordance with the current deliverability methodology. They can be on-peak, off-peak or both.
- Includes areas with commercial interest in which no deliverability constraints are identified

2. Affected zones

- Provides a general idea as to the location of resources that will be limited by the deliverability constraint
- More detailed locational information of resources affected by each constraint is provided in the form of substation-line diagrams or BES substation lists in a separate power point document.
- Constrained zones can be standalone, nested or overlapping

Explanation of the updated information - cont'd

3. Condition under which constraint is binding

- Indicates whether the constraint was identified in the on-peak scenario, off-peak scenario, both scenarios or neither scenario.
- Determines whether the associated FCDS and EODS capability estimates are actual or default as explained below.

4. Estimated existing system FCDS capability

- FCDS capability estimates associated with actual on-peak deliverability constraints represent the transmission plan deliverability (TPD) calculated for the constraint in accordance with the on-peak deliverability methodology.
- In areas where on-peak deliverability constraints are not identified, the amount of resources studied in the on-peak deliverability case are provided as "default" FCDS capability. Default FCDS estimates are marked by an asterisk.
- FCDS estimates are over and above the baseline contracted future resource amounts the CPUC transmitted for use in the ISO 2020-2021 TPP

Explanation of the updated information - cont'd

- Account for retirements of Diablo Canyon and OTC generating units assuming replacement resources are similarly located.
- FCDS estimates are expressed based on the resource-type specific resource output assumptions used in on-peak deliverability assessment rather than based on Interconnection Service Capacity (ISC).
- As a result, the FCDS capability estimates are resource-type neutral and can be translated into any combination of resource types by applying the applicable on-peak resource output factors shown below.

Resource output factors used in FCDS capability estimates

Resource type	HSN			SSN		
	SDG&E	SCE	PG&E	SDG&E	SCE	PG&E
Solar	3.0%	10.6%	10.0%	40.2%	42.7%	55.6%
Wind	33.7%	55.7%	66.5%	11.2%	20.8%	16.3%
Non-Intermittent resources	100%					
Energy storage	100% if duration is ≥ 4-hour or 4-hour equivalent if duration is less than 4-hour					
Hybrid	The lesser of 100% of combined ISC or [(Study amount of storage plus study amount of paired resource)/ISC]					

Explanation of the updated information - cont’d

5. Estimated incremental FCDS capability due to ADNU

- It provides an estimate of the incremental deliverable capacity due to identified conceptual ADNU and is expressed based on the same on-peak resource output assumptions.
- The incremental FCDS estimate is the incremental amount of additional queued generation behind the constraint that could be made deliverable by the identified ADNU.
- Incremental FCDS capability is not provided for areas with default existing system FCDS limits.

6. Description of ADNU

- A description of the ADNU, which is the basis for the incremental FCDS capability, is included to enable the CPUC to avoid double counting transmission upgrade cost in cases where an ADNU addresses more than one constraint.
- The information also includes estimated time to construct each ADNU that can be used to determine when the associated incremental capacity can become available.

Explanation of the updated information - cont’d

7. ADNU cost estimate

- The information will allow the CPUC to include transmission upgrade cost in the resource optimization.
- The costs estimates are escalated to the year of commercial operation.

8. Estimated existing system EODS capability

- Off-peak deliverability limits determined using the off-peak deliverability methodology are used as the basis for EODS capability estimates.
- By definition, OPDS limits and, therefore EODS limits, represent the limits on the amount of renewable resources beyond which curtailment would become excessive and potentially trigger transmission upgrades.
- Actual existing system EODS capability estimates are calculated for the off-peak constraints identified in GIDAP using data and results from the study.
- In areas where off-peak deliverability constraints are not identified, the amount of resources studied in the off-peak deliverability case are provided as “default” OPDS capability. Default OPDS estimates are marked by an asterisk.

Explanation of the updated information - cont'd

- While an actual EODS estimate is allowed to be less than the FCDS estimate, default EODS estimates are increased to the FCDS estimate to avoid unduly limiting the amount of FCDS resources that can be selected.
- EODS estimates are over and above the baseline contracted future resource amounts the CPUC transmitted for use in the ISO 2020-2021 TPP
- Energy storage increases EODS capability as it is dispatched in charging mode to address off-peak deliverability constraints. In order to avoid over estimating EODS capability, only existing and contracted energy storage resources are used in the assessment of EODS capability.
- EODS capability estimates are also expressed based on the resource output assumptions used in off-peak deliverability assessments rather than ISC.

Resource output factors used in EODS capability estimates

Resource type	Wind Area			Solar Area		
	SDG&E	SCE	PG&E	SDG&E	SCE	PG&E
Solar	68%			79%	77%	79%
Wind	69%	64%	63%	44%		
Hydro	30%					
Thermal	0%					
Energy storage	100% in charging mode if duration is ≥ 4-hour or 4-hour equivalent if duration is less than 4-hour					

Explanation of the updated information - cont'd

9. Estimated incremental EODS capability due to AOPNU

- It provides an estimate of the incremental EODS capacity due to conceptual AOPNUs that are primarily identified in GIDAP and is expressed based on the same off-peak resource output assumptions.

- The incremental EODS capability estimate is the incremental amount of queued generation behind the constraint that can be accommodated by the identified AOPNU.

- Incremental EODS capability is not provided for areas with default existing system EODS limits where off-peak constraints are not identified.

10. Description of AOPNU

- A description of AOPNUs, which provide the incremental EODS capability, enable the CPUC to avoid double counting transmission upgrade cost in cases where an AOPNU addresses more than one constraint.

- The information also includes estimated time to construct each AOPNU that can be used to determine when the associated incremental capacity could become available.

Explanation of the updated information - cont'd

11. AOPNU cost estimate

- The information will allow the CPUC to include transmission upgrade cost in the resource optimization.
- The costs estimates are escalated to the year of commercial operation.

12. Designation as Wind Area or Solar Area

- The transmission capability estimate information includes the designation of constrained areas as Wind Area or Solar Area in accordance with the off-peak deliverability methodology.
- The information indicates which wind and solar resource output factors above are applied in the EODS capability estimates. The same factors should be applied to implement the EODS capability estimates in RESOLVE.

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Intended implementation in the CPUC's resource planning

- This section provides the ISO's thinking, which has been discussed with the CPUC, as to how the transmission capability limits provided may be implemented in RESOLVE and the busbar mapping process.
- The CPUC may adjust the proposed implementation approach due to practical limitations or other reasons in consultation with the ISO.

<u>Representation of constraints as linear expressions</u>

- As explained earlier, the capability estimates are resource-type neutral and can be translated into any combination of resource type amounts by applying the respective deliverability study resource output factors.
- Each FCDS and EODS estimate can be implemented using three linear expressions in which the capacities of the resource types selected by RESOLVE are the variables and the applicable resource output factors are the coefficients.
- Implementing this approach in resource planning allows different resource types to take-up available deliverable capacity headroom in accordance with their resource output factors used in deliverability studies.

Implementation of FCDS capability estimates

- In order to ensure FCDS resources selected in IRP portfolios do not exceed on-peak deliverability constraints both in the HSN and SSN scenarios, each FCDS capability estimate can be implemented using the two linear expression shown below.

- <u>HSN Scenario</u>

*FCDS capability estimate ≥ Sum of the capacity of each resource type selected * respective resource output factor for the HSN scenario*

- <u>SSN Scenario</u>

*FCDS capability estimate ≥ Sum of the capacity of each resource type selected * respective resource output factor for the SSN scenario*

- Where FCDS capability estimate is the planned system FCDS capability estimate or the planned system FCDS capability plus the incremental FCDS capability due to ADNU.

Implementation of EODS capability estimates

- Each EODS capability estimate can be implemented using the linear expression below.

> *EODS capability estimate ≥ Sum of the capacity of each non-storage resource type selected * respective resource output factor for EODS estimates – Storage capacity selected (or 4-hour equivalent if duration is less than 4-hours)*

- Where EODS capability estimate is the planned system EODS capability estimate or the planned system EODS capability plus the incremental EODS capability due to AOPNU and the resource output factors for wind and solar are consistent with the designation of the area as Solar Area or Wind Area.
- Energy storage selected by RESOLVE is subtracted from the right hand side or added to the left hand side of the expression because it increases EODS capability as it is dispatched in charging mode to address off-peak deliverability constraints.

Baseline reconciliation

- As noted earlier, the transmission capability estimates are over and above the baseline contracted future resource amounts the CPUC transmitted as part of its resource portfolios for use in the ISO 2020-2021 TPP.
- The CPUC will need to adjust the estimates to account for additional resources that have been added to the baseline resource list since then.
- The respective resource output factors should be applied when adjusting the FCDS and EODS capability estimates to account for new baseline resources.

Policy-driven Assessment

Sensitivity 2 - Offshore Wind Studies

Ebrahim Rahimi
Regional Transmission North

2021-2022 Transmission Planning Process Stakeholder Meeting
July 27, 2021

Outline

- Offshore wind (OSW) sensitivity study
  - Detailed studies for 8,350 MW
  - Outlook assessment for 21,171 MW
- Review of interconnection options
- Next Steps

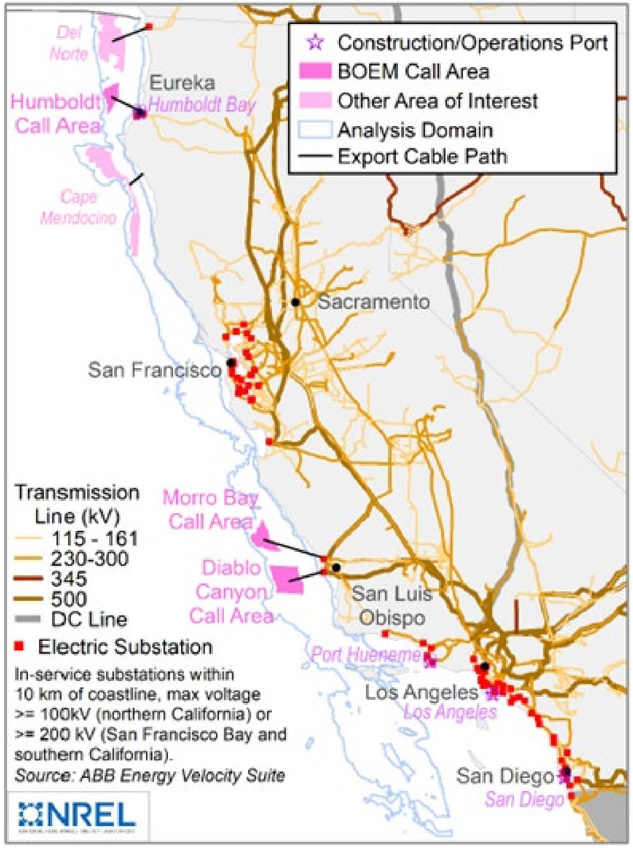
Portfolios for 2021-2022 TPP

- The CPUC transmitted a base portfolio and two sensitivity portfolios for the 2021-2022 TPP policy studies:
  - Base portfolio with 46 MMT GHG target
  - Sensitivity 1 portfolio with 38 MMT GHG target
  - Sensitivity 2 portfolio with 30 MMT GHG target
    - To assess the transmission needs for potential offshore wind development

Modeling Assumptions for the 2021-2022 Transmission Planning Process
ftp://ftp.cpuc.ca.gov/energy/modeling/Modeling_Assumptions_2021_22_TPP_Final.pdf

Description of Sensitivity 2 Portfolio

- Sensitivity 2 includes the following OSW resources:
  - Humboldt: 1.6 GW
  - Diablo Canyon: 4.3 GW
  - Morro Bay: 2.4 GW
- Detailed studies will be performed to identify the transmission needs for the above 8.35 GW
- In addition, an outlook assessment will be performed to accommodate the remaining OSW resource potential:
  - Del Norte: 6.6 GW
  - Cape Mendocino: 6.2 GW
- The total OSW in the outlook is 21,171 MW

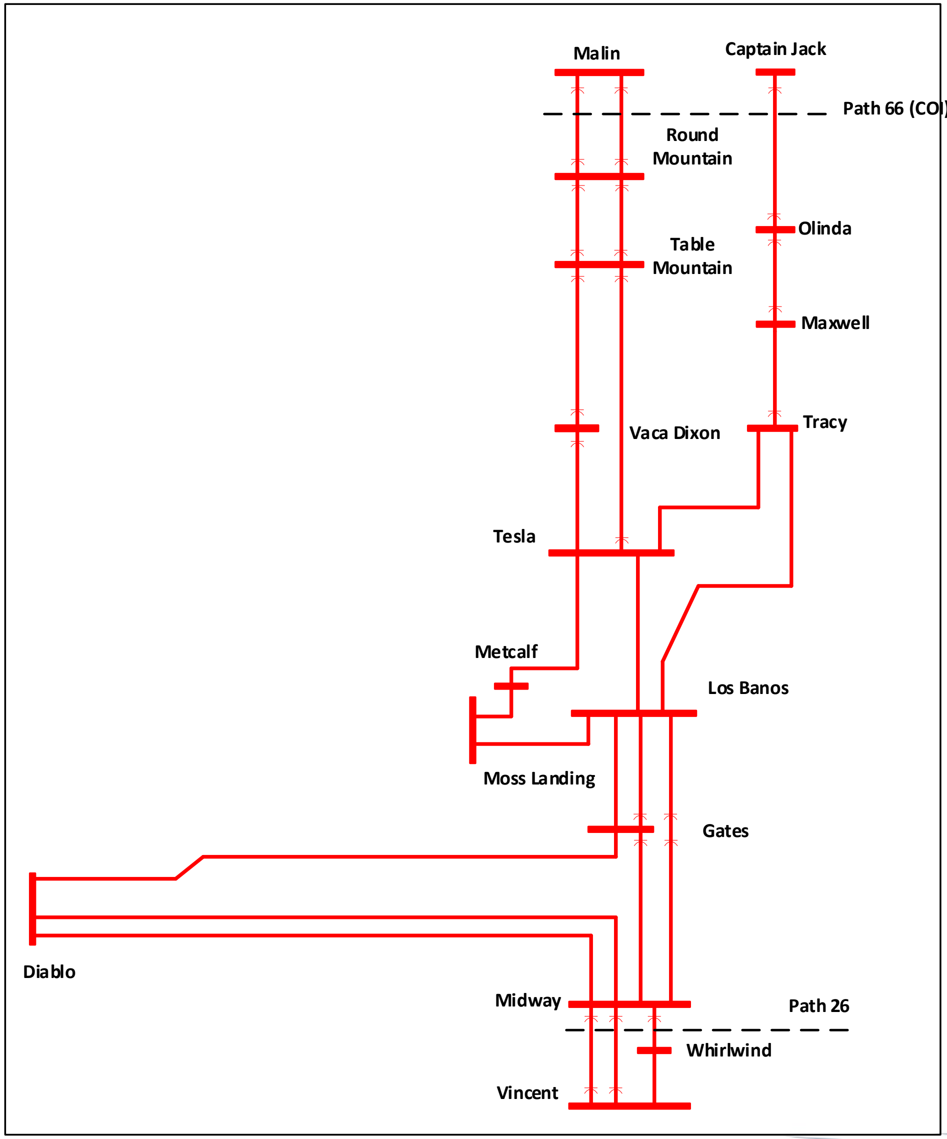


Source: [The Cost of Floating Offshore Wind Energy in California Between 2019 and 2032 (nrel.gov)]() (Page 39)

OSW and the existing bulk transmission system

Offshore wind ~20-30 mi from shore (14,428 MW)

Offshore wind ~30 mi from shore (6,743 MW)



California ISO

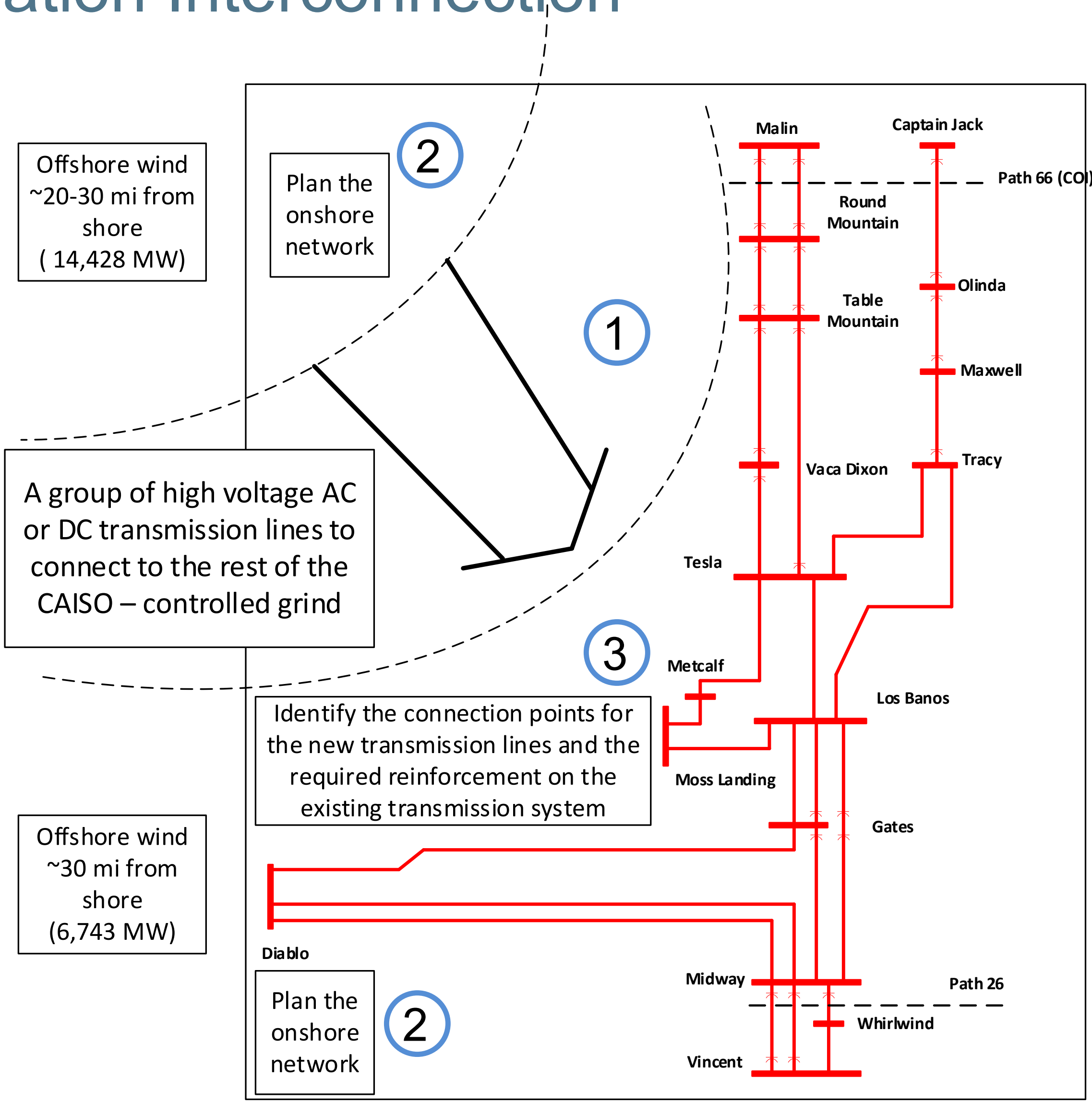
Offshore wind generation Interconnection

- The reinforcement requirements are grouped into 3 groups:

1. Transfer Path: The transmission lines to connect the onshore substations to the rest of the system.

2. The onshore network that connect the export cables to the rest of the system.

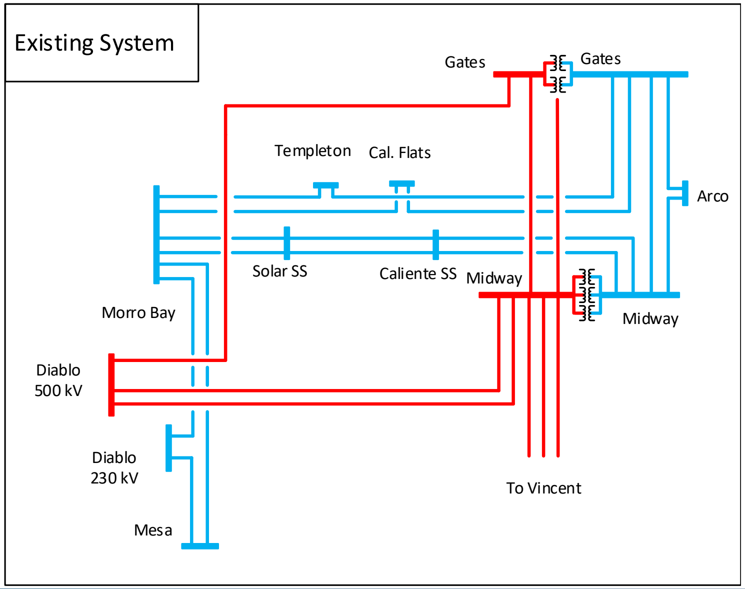
3. Other reinforcements required across the CAISO system to interconnect the OSW and reliably manage the resulting flows.

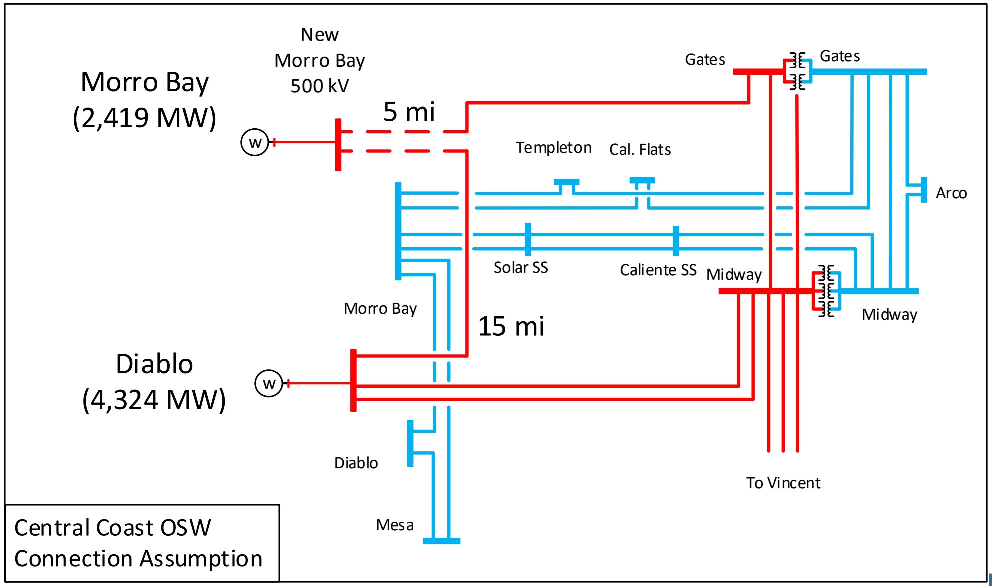


Onshore Connection Alternatives

Onshore Network Assumptions in Central Coast

- The 4.3 GW Diablo Canyon OSW will be connected to the Diablo 500 kV substation
- The capacity of Morro Bay 230 kV for new interconnection is around 1000 MW as per earlier studies. Therefore the 2.4 GW Morrow Bay OSW will be connected to a new 500 kV substation at Morrow Bay with Diablo – Gates 500 kV line looped into it





Transfer Path Alternatives for North Coast

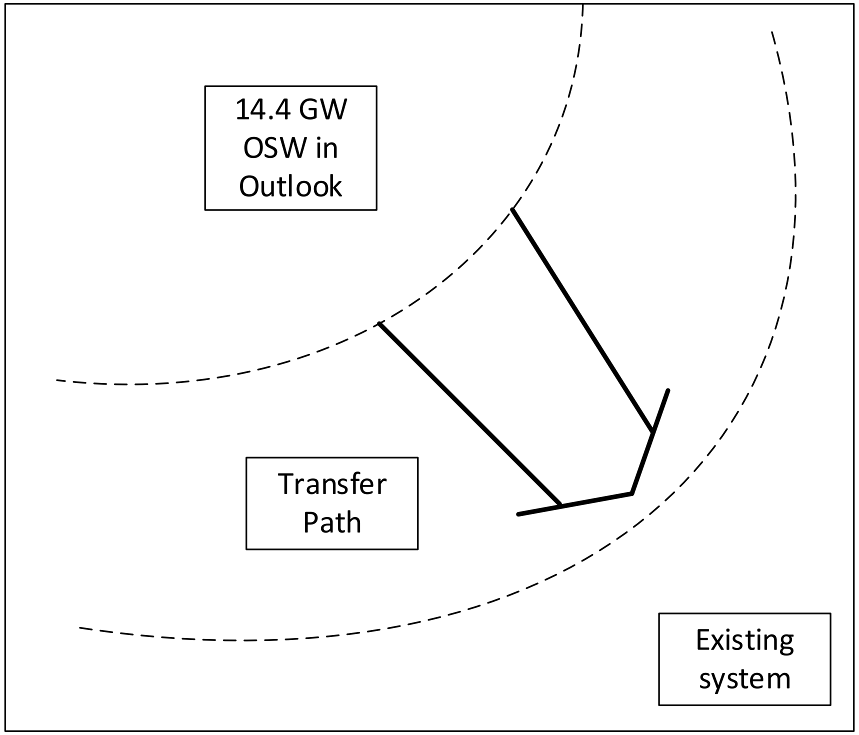
Humboldt 1.6 GW Interconnection Alternative

- The CPUC guidance in selecting transmission solutions for 8.35 GW is to be “least regret” if ultimate potential of 21.17 GW in outlook is developed.

- To follow the above, the transmission concept development for Humboldt 1.6 GW connection started with evaluating concepts to interconnect ultimate 14.4 GW.

Bulk Power Transfer Options

- High voltage AC lines
- Conventional (LCC) HVDC
- VSC-HVDC



High Voltage AC Lines

- The maximum nominal voltage rating in WECC is 500 kV.
- The advantages of AC line:
  - Is very common. Majority of bulk power transfer is done on AC line
  - They don't need converter stations
  - They could be easily looped into a new substation if required
- Potential Challenges:
  - They require series compensation at high power transfers
  - With the same power transfer capacity, they may require wider right of way
  - Flow on the line is based on network topology and load/generation pattern and cannot be easily controlled.
  - Long distance AC cables are not feasible/practical. Cable applications of 500 kV AC lines are very limited and only for very short distances.

Conventional (LCC) HVDC (1/2)

- PDCI and IPPDC are two ±500 kV LCC HVDC links connecting California to neighboring systems.

- PDCI is rated at 3,210 MW N-S with evaluations performed to increase it to 3,800 MW N-S. Much higher ratings are in operations around the world.

- The advantages of LCC HVDC:
  - Transmission over long distances
  - Transmission over long cables
  - Potentially smaller right of way
  - Flow control
  - Overload Capability

Conventional (LCC) HVDC (2/2)

- Potential Challenges:
  - Requires converter station at each end. For high power applications, the converter station may require significant area.
  - The AC system short circuit level should be above a certain threshold, especially at the receiving end.
  - Most of the schemes are point-to-point interconnection. “Looping in” the line for other interconnections (Multi-terminal HVDC applications) are rare.
  - HVDC converters consume reactive power which in absolute value is around 50-60% of the operating real power.

VSC-based HVDC (1/2)

- Trans Bay Cable is a 400 MW VSC-HVDC link in service in California.

- Most high power installations are around 1000 MW with new projects planned for 1,400 MW by Siemens and ABB. Higher capacity VSC-HVDCs exist but are uncommon.

- The advantages of VSC HVDC in addition to LCC HVDC:
  – Does not require short circuit level in the AC system.
  – The converter station is smaller compared to LCC HVDC and therefore more suitable to deliver power to urban centers.
  – Does not require reactive power support at the converter station.
  – Multi-terminal configuration

VSC-based HVDC (2/2)

- Potential Challenges:
  - The power rating is lower than LCC HVDC.
  - It is challenging to design schemes with overhead lines. Almost all applications are cable connections.
  - The converter station losses are higher

CAISO Generation Drop Limits

- The ISO Planning Standard indicates the following limits:
  - The generation drop following N-1 contingency should be limited to 1,150 MW
  - The generation drop following N-2 (DCTL) contingency should be limited to 1,400 MW
- The above limits will be taken into account in the development of transfer path concepts.

Bulk Transmission for 14.4 GW of Offshore Wind

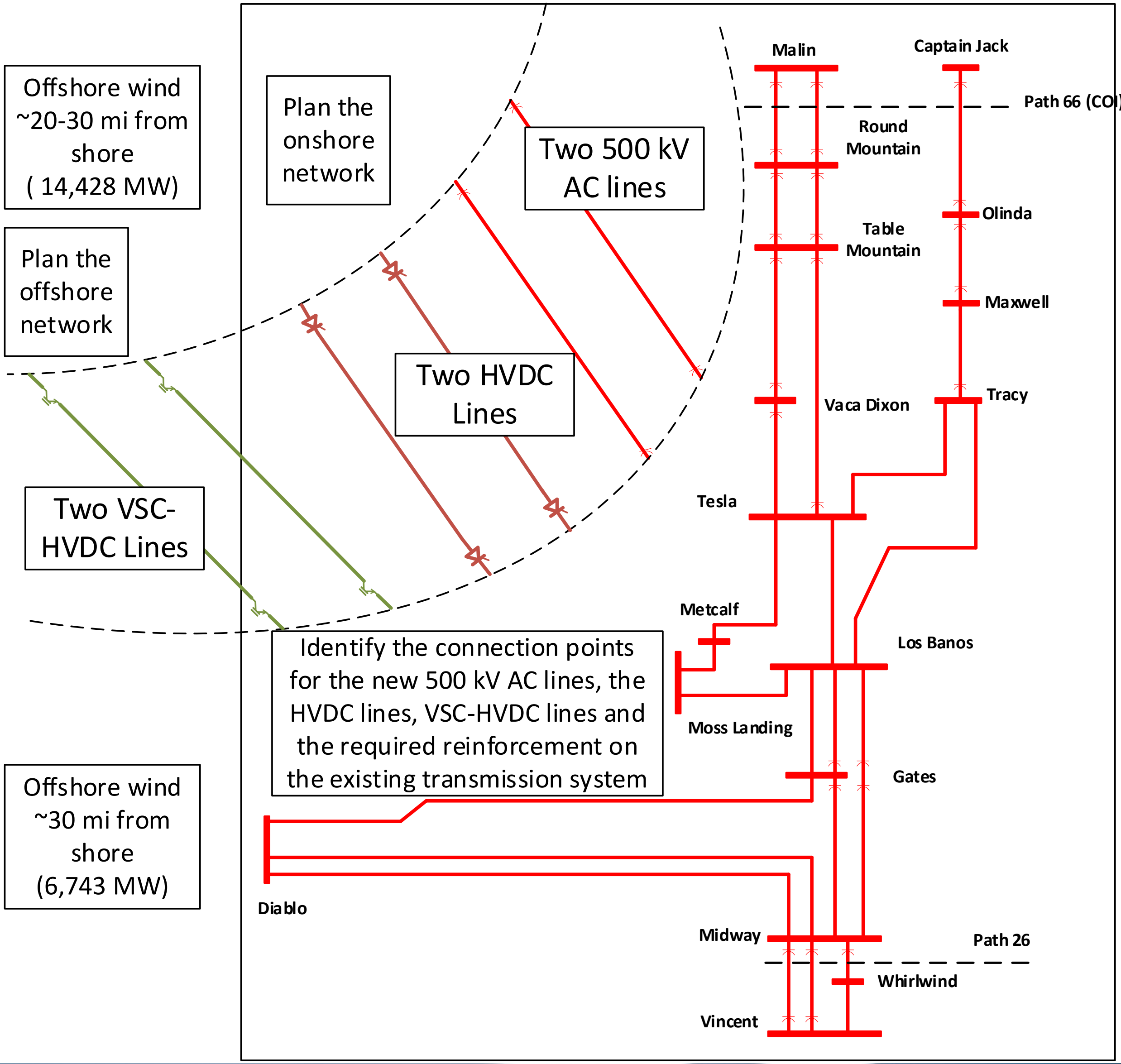
- High voltage AC lines are the most common technology for bulk power transfers.
  – Depending on the ratings, 5 to 6 500 kV AC lines would be required to reliably transfer 14.4 GW.

- LCC HVDC is suitable for high power over long distance with right of way limitations.
  – Four HVDC bipoles with reasonable short term overload capability could reliably transfer 14.4 GW.

- VSC-HVDC is suitable for delivering power to urban areas and systems with low short circuit levels.
  – Considering 1,400 MW maximum rating, at least 11 underground/subsea cable schemes would be required to reliably transfer 14.4 GW of power.

Transfer Path from North Coast for 14.4 GW OSW

- Potentially a hybrid AC and DC solution could be considered as the preferred concept to connect the 14.4 GW of offshore wind in the outlook assessment.



California ISO

Humboldt 1.6 GW Interconnection Alternatives (1/2)

- Considering the “least regret” approach, the following interconnection options for Humboldt 1.6 GW will be studied in detail:
  - Option 1: 500 kV AC line to Fern Road 500 kV substation.
    - Fern Road 500 kV substation is planned to be in service by 2024 as part of Round Mountain DRS project and is located 11 miles south of Round Mountain substation.
  - Option 2: 500 kV AC line to Collinsville 500/230 kV substation.
    - Collinsville 500 kV substation is a concept studied in prior TPPs to reduce reliance on gas generation in the Bay area. Vaca Dixon – Tesla 500 kV line is looped into it with two 230 kV connections to Pittsburg 230 kV substation.

Humboldt 1.6 GW Interconnection Alternatives (2/2)

- Option 3: VSC-HVDC subsea cable connection to a converter station in the Bay area
  - From the converter station, new connections to the existing substations in San Francisco Peninsula, South Bay and East Bay areas will be required.

- The generation drop limitation under N-1 and N-2 contingencies will be taken into account in developing the above alternatives.

Next Steps

1. Perform deliverability, production cost, and reliability studies on 8.35 GW OSW considering three options for Humboldt 1.6 GW interconnection.

2. Identify the reliability and deliverability network upgrades required for the 8.35 GW OSW.

3. Obtain cost estimates for the interconnection as well the required reliability and deliverability network upgrades.

4. Preliminary results will be provided in the November stakeholder meeting.

Economic Assessment Assumption Update for 2021-2022 Planning Cycle

Yi Zhang

2021-2022 Transmission Planning Process Stakeholder Meeting
July 27, 2021

Co-located and hybrid resource model in GridView

California ISO

Summary of modeling requirements

Category of comparison	Co-located	Hybrid
System dispatch in actual system operation	TWO standalone generators subject to certain Pmin and Pmax constraints	ONE generator subject to certain Pmin and Pmax constraints.
Sub-system optimization in actual system operation	No	Maybe (resource operato's decision, but not supported by PCM software)
Pmax constraint	Combined Pmax constraint <= ACC	One Pmax <= ACC
Pmin (charing from the grid) constraint	Can charge from the grid (may lose tax credit)	Can charge from the grid
Ancillary Services	Two resources but need to meet Pmin and Pmax constraints	One resource but need to meet Pmin and Pmax constraints

Add two constraints in PCM for co-located and hybrid resources

- *Pmax constraint*

$$P_{solar} + P_{battery} + REGUP_{battery} + LFUP_{solar} + LFUP_{battery} + Spin_{battery} + FR_{battery} \leq Pmax \quad (1)$$

- *Pmin constraint (charging constraint)*

$$P_{solar} + P_{battery} - REGDOWN_{battery} - LFDOWN_{solar} - LFDOWN_{battery} \geq Pmin \quad (2)$$

* These two constraints are similar to the Pmax and Pmin constraints of the any other generators; Pmax is normally equal to the ACC at POI, and the Pmin can be equal to zero if the battery component is not expected to charge from the grid.

** $P_{battery}$ is positive when the battery is discharging, and is negative when the battery is charging.

*** The transmission constraints associated with co-located or hybrid resources identified in other planning studies can be considered in the planning PCM separately as a part of transmission constraint model.

Penalty price for the Pmax constraint

- The total energy output and the AS awards should not exceed the Pmax
- Can use a large penalty price greater than the maximum LMP, for example P1 = $6000/MW
  - This can be the same for both co-located and hybrid resources
  - The sub-Pmax constraint is not considered in this discussion

Penalty price selection based on two test cases

- Test 1: Two solar and one battery storage were selected
  - Solar Pmax: 518 MW (each solar has 259 MW Pmax)
  - Battery Pmax: 209 MW; Pmin: -200 MW
  - Pmax of the combined resource: 518 MW
- Test 2: One solar and one battery storage were selected
  - Solar Pmax: 259 MW
  - Battery Pmax: 209 MW; Pmin: -200 MW
  - Pmax of the combined resource: 259 MW

Energy and hours of total charging vs. charging from grid

	Test1: Battery Pmax/Solar Pmax = 209MW/518MW						Test2: Battery Pmax/Solar Pmax = 209MW/259MW					
	Total charged energy (MWh)	Energy charged from grid (MWh)*	Ratio	Hours of charging	Hours of charging from grid*	Ratio	Total charged energy (MWh)	Energy charged from grid (MWh)*	Ratio	Hours of charging	Hours of charging from grid*	Ratio
Standalone**	282,573	22,150	7.84%	1,485	409	27.54%	282,573	88,408	31.29%	1,485	1,115	75.08%
Penalty0	283,204	22,684	8.01%	1,483	416	28.05%	283,134	88,783	31.36%	1,475	1,121	76.00%
Penalty0.1	282,944	19,246	6.80%	1,482	368	24.83%	282,929	83,482	29.51%	1,492	1,085	72.72%
Penalty0.5	282,831	10,887	3.85%	1,496	220	14.71%	282,847	66,652	23.56%	1,537	919	59.79%
Penalty1	283,080	3,543	1.25%	1,506	75	4.98%	281,896	43,198	15.32%	1,574	703	44.66%
Penalty2	283,138	1,102	0.39%	1,503	14	0.93%	281,271	19,048	6.77%	1,614	437	27.08%
Penalty7	283,015	657	0.23%	1,505	8	0.53%	281,278	9,478	3.37%	1,628	279	17.14%
Penalty13	283,105	641	0.23%	1,507	8	0.53%	279,579	8,423	3.01%	1,627	254	15.61%
Penalty20	282,240	150	0.05%	1,514	2	0.13%	276,075	4,116	1.49%	1,625	130	8.00%
Penalty27	283,027	0	0.00%	1,513	0	0.00%	271,971	0	0.00%	1,631	0	0.00%

* Charging from grid when the charged energy is greater than the on-site solar generation energy in the same hour

** Standalone scenario: BS and solar are modeled as standalone generators without Pmax and Pmin constraints.

Annual generation and AS results – Test 1

Scenario	Generator_Name	Bus_ID	MaxCap (	MinCap(M	Generatio	Pumping	Dumped_	RegUp_A	RegDn_A	Spin_Awa	LFUp_Aw	LFDn_Aw	FreqRp_A
Standalone	BS_Antlop2_B1	29698	209	-200	240,188	282,574	0	207,608	199,165	48,202	105,918	346,631	138,271
Standalone	Antlop2_G1	29698	259	0	493,019	0	123,765	0	0	0	1,080	63	0
Standalone	Antlop2_G2	29698	259	0	492,915	0	123,869	0	0	0	1,002	65	0
Penalty0	BS_Antlop2_B1	29698	209	-200	240,724	283,204	0	191,127	201,871	56,246	103,403	344,066	125,299
Penalty0	Antlop2_G1	29698	259	0	492,940	0	123,845	0	0	0	949	63	0
Penalty0	Antlop2_G2	29698	259	0	492,758	0	124,027	0	0	0	934	63	0
Penalty0.1	BS_Antlop2_B1	29698	209	-200	240,502	282,944	0	191,239	147,215	49,059	101,516	174,252	132,167
Penalty0.1	Antlop2_G1	29698	259	0	493,986	0	122,799	0	0	0	1,001	93	0
Penalty0.1	Antlop2_G2	29698	259	0	494,253	0	122,531	0	0	0	978	93	0
Penalty0.5	BS_Antlop2_B1	29698	209	-200	240,407	282,832	0	187,509	147,890	48,803	96,803	170,423	147,458
Pnealty0.5	Antlop2_G1	29698	259	0	498,010	0	118,774	0	0	0	1,055	93	0
Penalty0.5	Antlop2_G2	29698	259	0	498,053	0	118,731	0	0	0	990	93	0
Penalty1	BS_Antlop2_B1	29698	209	-200	240,619	283,081	0	193,969	144,738	56,446	98,827	172,840	134,698
Penalty1	Antlop2_G1	29698	259	0	501,883	0	114,901	0	0	0	1,046	93	0
Penalty1	Antlop2_G2	29698	259	0	501,856	0	114,929	0	0	0	940	93	0
Penalty2	BS_Antlop2_B1	29698	209	-200	240,668	283,138	0	158,020	121,809	39,755	84,767	159,582	112,387
Penalty2	Antlop2_G1	29698	259	0	502,851	0	113,934	0	0	0	1,123	80	0
Penalty2	Antlop2_G2	29698	259	0	502,795	0	113,990	0	0	0	1,003	90	0
Penalty7	BS_Antlop2_B1	29698	209	-200	240,563	283,015	0	151,999	127,050	41,398	87,115	150,526	117,231
Penalty7	Antlop2_G1	29698	259	0	503,277	0	113,508	0	0	0	1,033	91	0
Penalty7	Antlop2_G2	29698	259	0	503,233	0	113,552	0	0	0	936	34	0
Penalty13	BS_Antlop2_B1	29698	209	-200	240,639	283,105	0	169,886	137,941	51,538	98,190	170,819	130,774
Penalty13	Antlop2_G1	29698	259	0	503,459	0	113,326	0	0	0	1,078	86	0
Penalty13	Antlop2_G2	29698	259	0	503,777	0	113,008	0	0	0	1,026	44	0
Penalty20	BS_Antlop2_B1	29698	209	-200	239,904	282,240	0	184,826	137,315	59,453	106,343	177,225	134,929
Penalty20	Antlop2_G1	29698	259	0	504,052	0	112,733	0	0	0	1,021	75	0
Penalty20	Antlop2_G2	29698	259	0	503,377	0	113,407	0	0	0	940	26	0
Penalty27	BS_Antlop2_B1	29698	209	-200	240,573	283,027	0	199,495	152,234	48,066	110,335	179,835	137,326
Penalty27	Antlop2_G1	29698	259	0	503,640	0	113,144	0	0	0	1,010	117	0
Penalty27	Antlop2_G2	29698	259	0	504,016	0	112,768	0	0	0	928	109	0

Annual generation and AS results – Test 2

Scenario	Generator_Name	Bus_ID	MaxCap (	MinCap(M	Generatio	Pumping	Dumped_	RegUp_A	RegDn_A	Spin_Awa	LFUp_Aw	LFDn_Aw	FreqRp_A
Standalone	BS_Antlop2_B1	29698	209	-200	240,188	282,574	0	207,608	199,165	48,202	105,918	346,631	138,271
Standalone	Antlop2_G1	29698	259	0	493,019	0	123,765	0	0	0	1,080	63	0
Standalone	Antlop2_G2	29698	259	0	492,915	0	123,869	0	0	0	1,002	65	0
Penalty0	BS_Antlop2_B1	29698	209	-200	240,664	283,134	0	173,163	205,053	47,203	89,133	340,353	133,663
Penalty0	Antlop2_G1	29698	259	0	493,030	0	123,755	0	0	0	964	93	0
Penalty0	Antlop2_G2	29698	259	0	493,024	0	123,761	0	0	0	990	93	0
Penalty0.1	BS_Antlop2_B1	29698	209	-200	240,490	282,929	0	169,048	106,384	48,873	88,914	129,337	131,944
Penalty0.1	Antlop2_G1	29698	259	0	497,190	0	119,594	0	0	0	1,028	44	0
Penalty0.1	Antlop2_G2	29698	259	0	492,487	0	124,298	0	0	0	985	12	0
Penalty0.5	BS_Antlop2_B1	29698	209	-200	240,420	282,847	0	177,757	103,730	49,328	88,965	127,394	131,105
Pnealty0.5	Antlop2_G1	29698	259	0	510,797	0	105,987	0	0	0	1,041	63	0
Penalty0.5	Antlop2_G2	29698	259	0	492,824	0	123,960	0	0	0	965	63	0
Penalty1	BS_Antlop2_B1	29698	209	-200	239,612	281,896	0	175,923	104,603	48,420	91,508	125,383	132,699
Penalty1	Antlop2_G1	29698	259	0	530,057	0	86,728	0	0	0	1,015	63	0
Penalty1	Antlop2_G2	29698	259	0	492,699	0	124,086	0	0	0	1,000	63	0
Penalty2	BS_Antlop2_B1	29698	209	-200	239,081	281,271	0	175,919	102,854	48,241	89,656	123,861	138,492
Penalty2	Antlop2_G1	29698	259	0	550,610	0	66,175	0	0	0	1,061	95	0
Penalty2	Antlop2_G2	29698	259	0	492,350	0	124,435	0	0	0	974	93	0
Penalty7	BS_Antlop2_B1	29698	209	-200	239,087	281,278	0	173,729	102,293	49,418	89,748	122,575	141,687
Penalty7	Antlop2_G1	29698	259	0	558,510	0	58,275	0	0	0	1,061	63	0
Penalty7	Antlop2_G2	29698	259	0	492,094	0	124,691	0	0	0	987	63	0
Penalty13	BS_Antlop2_B1	29698	209	-200	237,642	279,579	0	172,515	102,623	48,502	91,379	122,081	138,745
Penalty13	Antlop2_G1	29698	259	0	558,258	0	58,527	0	0	0	1,072	95	0
Penalty13	Antlop2_G2	29698	259	0	492,261	0	124,524	0	0	0	999	93	0
Penalty20	BS_Antlop2_B1	29698	209	-200	234,664	276,075	0	163,629	99,886	50,936	96,442	125,226	143,643
Penalty20	Antlop2_G1	29698	259	0	558,388	0	58,397	0	0	0	1,027	73	0
Penalty20	Antlop2_G2	29698	259	0	491,510	0	125,275	0	0	0	966	17	0
Penalty27	BS_Antlop2_B1	29698	209	-200	231,130	271,917	0	174,872	100,729	51,463	92,615	127,236	137,278
Penalty27	Antlop2_G1	29698	259	0	558,230	0	58,555	0	0	0	1,008	111	0
Penalty27	Antlop2_G2	29698	259	0	491,718	0	125,066	0	0	0	967	109	0

Observations from charging, generation, and AS results

- Compared with the standalone generator model
  - Curtailment of the renewable generation of the co-located or hybrid resource reduced
  - The battery component of the co-located or hybrid resource was less used for regulation and load following
- As the penalty price increases further, both the utilization of the battery and the curtailment of the solar reduced slightly
- Note that the overall generation dispatch and transmission congestion results will also impact the charging pattern of co-located and hybrid resources

Consider tax credit for charging from the on-site solar

- Co-located resources can obtain tax credit for charging from the on-site solar component
  - Tax credit will phase out within the five years starting from the resource's in-service date
  - Actual tax credit a resource can obtain may vary depending on the ratio of energy charged from the grid
- In the CPUC's portfolio for 2031, the co-located or hybrid resources identified are all existing, or under construction, or with contract
  - Likely the tax credit for those resources would have expired by 2031 or soon after 2031
- It is reasonable to assume no tax credit for co-located resources in the PCM for economic assessment
  - i.e. there would no limitation or requirements for co-located resources charging from the grid

Recommendations for the planning PCM in the 2021-2022 cycle

- Model the renewable generators and battery storage generators of co-located or hybrid resources as individual generators with additional constraints
- Model Pmax constraint for all co-located and hybrid resources with $6,000/MWh penalty price
- Not model the Pmin constraint for all co-located and hybrid resources
  - But this will be reviewed in future as there are additional clarity of charging tax credit or operation requirements for co-located or hybrid resources.
  - Sensitivity or alternative assumption may be considered upon future review. For example, the Pmin constraint may be enforced with a large penalty e.g. $30/MWh that essentially assumes the battery component will only charge from the on-site solar component.

Battery operation cost update

California ISO

Battery operation cost used in previous planning cycle's PCM

- In the CAISO's 2019-2020 TPP cycle, the planning PCM started to model battery's operation cost based on the equation below:

$$Average\ Cost = \frac{Per\ unit\ replacement\ cost}{Cycle\ life * DoD * 2}$$

- The 2025 forecast obtained from the DOE (DOE/Hydro Wires report, July 2019) was used for battery operation cost calculation:
  - DoD: 80%
  - Cycle life: 3500 cycles
  - Per unit replacement cost: $189,000/MWh
- Note that these parameters were used for battery operation cost calculation only. The batteries were still modeled at their full capacity in PCM

New battery operation cost is recommended

- PNNL worked with DOE to prepare an updated the report in 2020 with the following parameter changes:
  - DoD: 80%
  - Cycle life: 2100 cycles
  - Per unit replacement cost: $99,000/MWh
- With this new cost forecast, the updated battery operation cost is $29.54/MWh, compared with $33.75/MWh in the previous cycle's PCM
- The DOE reports can be found from the links below
  - The 2019 report

    https://www.sandia.gov/ess-ssl/wp-content/uploads/2019/07/PNNL_mjp_Storage-Cost-and-Performance-Characterization-Report_Final.pdf
  - The 2020 report

    https://www.pnnl.gov/sites/default/files/media/file/Final%20-%20ESGC%20Cost%20Performance%20Report%2012-11-2020.pdf

Out of State Wind In Portfolios - Update

Jeff Billinton
Director, Transmission Infrastructure Planning

July 27, 2021
2021-2022 Transmission Planning Process

2021-2022 Transmission Planning Process CPUC Portfolios

- For the 2021-2022 planning cycle, the CPUC provided:
  - a “base” portfolio for reliability, policy and economic study purposes – for potential transmission upgrade approval purposes
  - Sensitivities for informational studies.
- These portfolios include out of state resources, raising questions as to if or how the ISO would examine out of state transmission needs

Out of State Wind in Portfolios

- The economic assessment of the base portfolio will assess the transmission outside of the CAISO system

- The CAISO will also assess as a special study a comparison of transmission alternatives for the out of state wind in the Sensitivity 1 portfolio provided by the CPUC
  - Analysis of the out state transmission alternatives will only include production cost simulation
  - Same scope as presented at May 14 stakeholder call

Out of State Wind in CPUC Base Portfolio

- Out of state wind requiring transmission
  - The CPUC IRP base portfolio includes OOS wind with 1062 MW of capacity identified *in two alternative locations*, Wyoming or New Mexico areas, that require transmission
  - The Base Portfolio provided specified injection points for the OOS wind, it was not specified how the OOS wind would be delivered to the injection points.
- Portfolio also includes out of state wind on existing transmission
    - 530 MW in Pacific Northwest

Alternative Transmission Projects

- Alternative transmission projects will be assessed for the OOS wind in the Wyoming (or Idaho) area
  – 1062 MW of OOS wind in the Idaho area will be studied as an alternative to the OOS wind in the Wyoming area
- The alternatives will include projects that have submitted previously as interregional transmission projects or assessed in previous TPP assessments
  – TransWest Express project
  – SWIP North project
  – Cross-tie project

Study Approach for Out of State Wind Base Portfolio Study

- Production benefit of the interregional transmission projects will be assessed
- The PCM case with the New Mexico wind that require new transmission will be used as the reference “pre” case for production benefit calculation
  - The1062 MW of New Mexico wind will be modeled at Pinal Central 500 kV bus
- The “post” cases will model the OOS wind generators in Wyoming and Idaho
  - Wyoming wind generators will be modeled at the Aeolus 500 kV bus
  - Idaho wind generators will be modeled at the MidPoint 500 kV bus

Gateway West Sensitivity Study for the Out of State Wind Base Portfolio Study

- Economic benefit assessment - the CAISO's TEAM methodology requires sensitivities of key parameters to be evaluated
- In the OOS wind base portfolio study, the development status of the Gateway West project, especially the segments between Bridger to Hemingway, is considered as the critical parameters
  - These segments provide additional transmission connection between the Wyoming and Idaho systems
- Sensitivity studies assuming these segments of the Gateway West project not in service will be conducted

Out of State Wind Special Study - Timeline

- Targeting to provide preliminary analysis at the November Stakeholder meeting
  - Gateway West sensitivity study results may be presented at the February Stakeholder meeting

- Will be incorporated into the Draft 2021-2022 Transmission Plan to be posted on January 31, 2022

20 Year Transmission Outlook - Update

Jeff Billinton

Director, Transmission Infrastructure Planning

July 27, 2021

The 20-year transmission outlook initiative will be coordinated with 2021-2022 transmission planning process

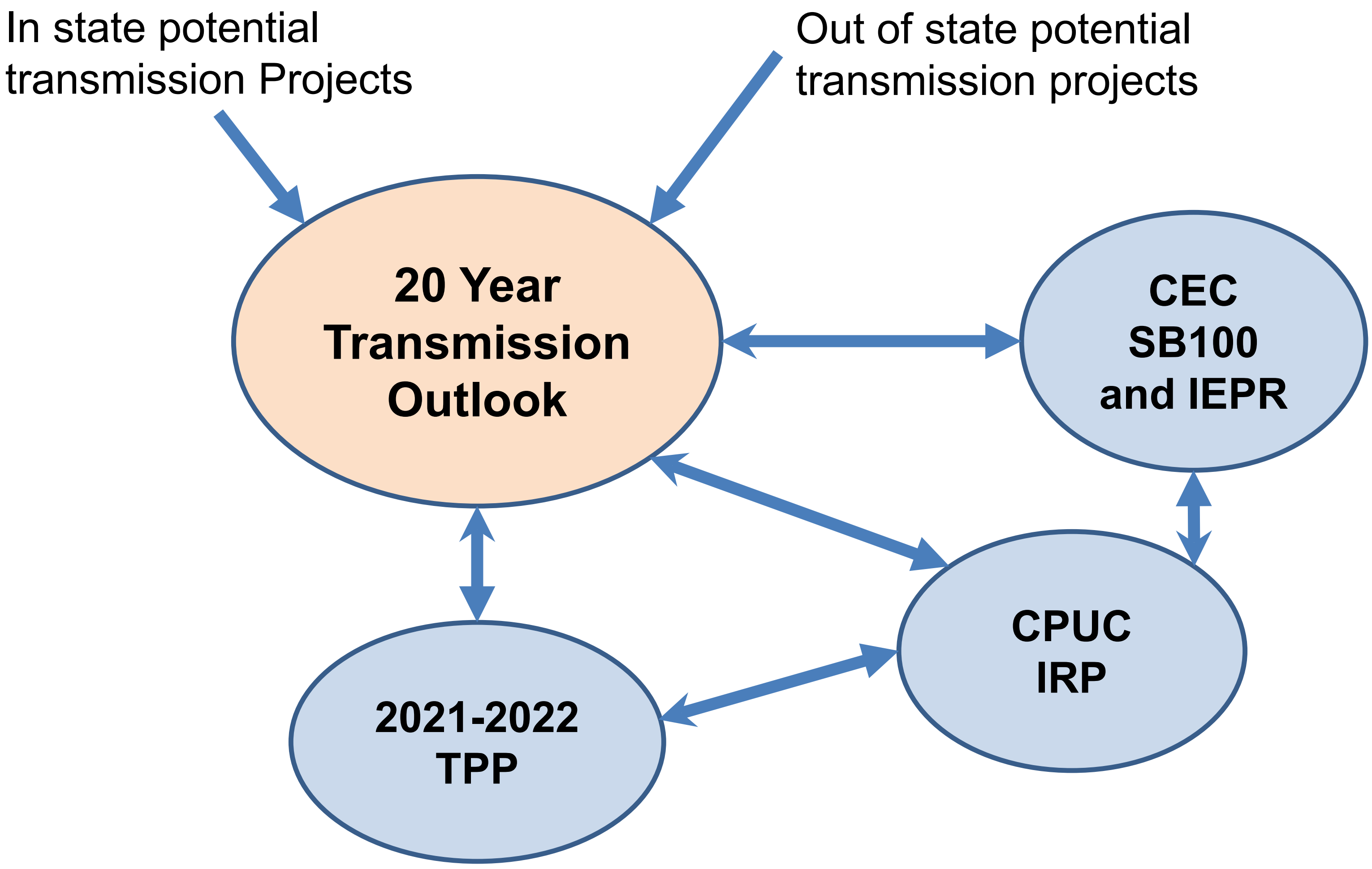
- The Outlook will include higher level technical studies to test feasibility of alternatives, and not the detailed level of comprehensive analysis that underpins the 10-Year Transmission Plan

- Accordingly the Outlook will coordinate with currently scheduled 10-Year Transmission Plan stakeholder sessions to the extent possible, and hold separate stakeholder sessions as appropriate.

- Coordination with the California Energy Commission SB100 and California Public Utilities Commission IRP

- The process welcomes and will incorporate stakeholder input and consultation.

Primary Paths for Coordination with Other Initiatives



SB100 July 22 Workshop
In and Out of State Transmission Projects

- Pacific Transmission Expansion Project
- North Gila Imperial Valley #2 Transmission Project
- TransWest Express Transmission Project
- Southwest Intertie Project (SWIP) North
- Cross Tie Project
- Sunzia Southwest Transmission Project
- Ten West Link Project
- Southline Transmission Project
- Lucky Corridor Transmission Project
- GridLiance West
- https://efiling.energy.ca.gov/GetDocument.aspx?tn=238965&DocumentContentId=72387

SB100 No Combustion Scenario – Year 2040

Resource Type	**2040**
Gas	-
Hydrogen Fuel Cell	4,434
Geothermal	2,300
Biomass	-
Wind	4,779
New OOS Wind	11,215
Offshore Wind	9,651
Utility-Scale Solar	52,058
Customer Solar	22,961
Battery Storage	37,520
Long Duration Storage	4,000
Shed DR	1,111
Gas Capacity Not Retained	-15391

Geographic Granularity of RESOLVE Transmission Zones

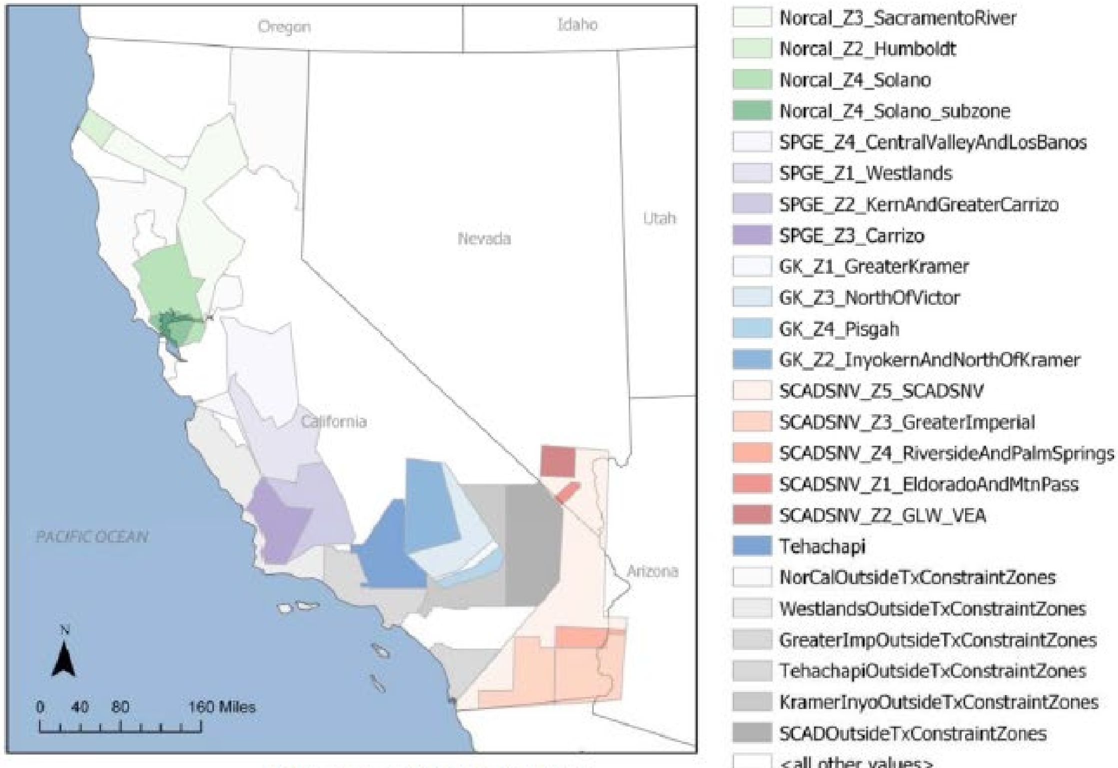


Figure 4.1, Inputs & Assumptions
ftp://ftp.cpuc.ca.gov/energy/modeling/Inputs%20%20Assumptions%202019-2020%20CPUC%20IRP%202020-02-27.pdf

https://efiling.energy.ca.gov/GetDocument.aspx?tn=238965&DocumentContentId=72387

CEC Land Use and Mapping of Resources

SB 100 Implementation Environmental and Land Use

- Estimating potential renewable energy development footprint by technology
- Identifying coarse geographic locations of resources within transmission zones used in the RESOLVE modeling
- Screening with identified statewide environmental and land use land use datasets
- Calculating available acreage of potential renewable energy resource by transmission zone
- Creating a "Starting Point" Resource Map to:
  - inform CAISO 20 Year Transmission Look
  - iterate in ongoing SB 100 implementation work

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https://efiling.energy.ca.gov/GetDocument.aspx?tn=238965&DocumentContentId=72387

CEC Example Map

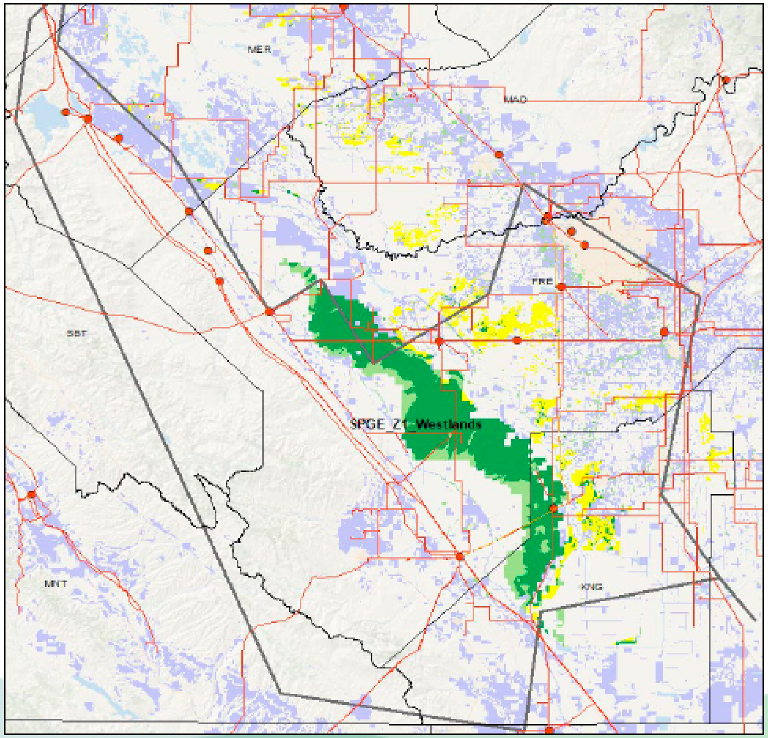
Example Map Wetlands Tx Zone Solar Resource

Least Conflict Solar Areas (green and yellow)

Suitable Areas for Solar (light purple)

Next Steps:

- Iterate Environmental and Land Use Screens
- Calculate Range of Available Resource Acres
- Assign RESOLVE MW by Transmission Zone
- Adjust MW if Necessary
- Share w/Stakeholders
- Inform CAISO Tx Work



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https://efiling.energy.ca.gov/GetDocument.aspx?tn=238965&DocumentContentId=72387

Assumptions for Outlook technical studies coordinated with CEC SB100 and CPUC IRP

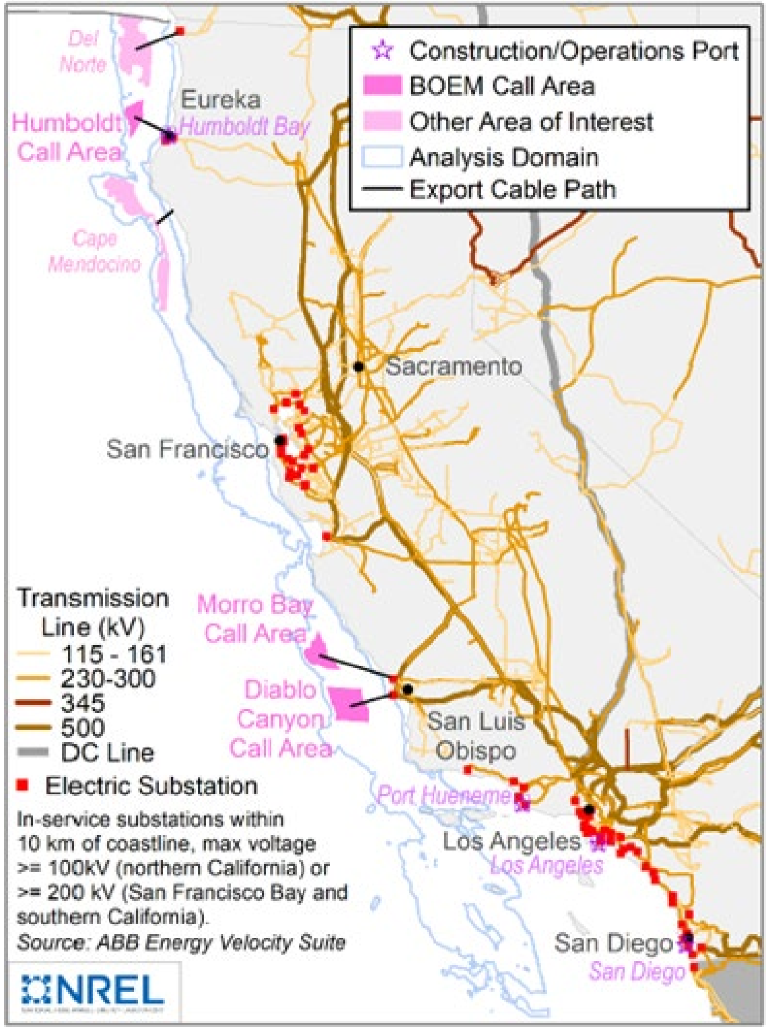
- Continued coordination for the mapping of resources:
  - Solar mapping - *currently under way*
  - Storage mapping
  - Wind
    - On shore, Off shore, and Out of state
  - Geothermal
  - Gas retirement
    - Criteria being developed
      - Age, disadvantaged communities, etc.
      - Build off analysis from 2018-2019, 2019-2020 and 2020-2021 transmission planning processes in local capacity areas

Coordination with 2021-2022 TPP Policy Sensitivity 2 on Offshore Wind Portfolio

- Sensitivity 2 includes the following OSW resources:
  - Humboldt: 1.6 GW
  - Diablo Canyon: 4.3 GW
  - Morro Bay: 2.4 GW

- Detailed studies will be performed to identify the transmission needs for the above 8.3 GW

- In addition, an outlook assessment will be performed to accommodate an additional 12.8 GW of offshore wind (totaling 21.1 GW)
  - Del Norte: 6.6 GW
  - Cape Mendocino: 6.2 GW



Source: The Cost of Floating Offshore Wind Energy in California Between 2019 and 2032 (nrel.gov) (Page 39)

California ISO

20 Year Transmission Outlook Milestones

- Stakeholder call initiating Outlook on May 14
  - Comments to be submitted by May 28
- Coordination with CEC workshops on SB100
  - SB 100 Workshop on June 2
  - SB100 Workshop – Transmission Projects on July 22
  - SB100 Workshop – Land use / Resource Mapping in August
- Stakeholder call – Transmission Planning Update on July 27
  - Comments to be submitted by August 10
- Update at 2021-2022 TPP Stakeholder call on September 27 and 28
  - Comments to be submitted by October 12
- Update at 2021-2022 TPP Stakeholder call on November 18
  - Comments to be submitted by December 6
- Draft 20 Year Transmission Outlook as standalone document together with draft 2021-2022 Transmission Plan to be posted on January 31, 2022
- Stakeholder meeting in February

Next Steps

Isabella Nicosia
Stakeholder Engagement and Policy Specialist

July 27, 2021

Comments

- Comments due by end of day August 10, 2021
- Submit comments through the ISO’s commenting tool, using the template provided on the process webpage: https://stakeholdercenter.caiso.com/RecurringStakeholderProcesses/2021-2022-Transmission-planning-process

Comments will be submitted to the ISO using the online stakeholder commenting tool

- Ability to view all comments with a single click.
- Ability to filter comments by question or by entity.
- Login, add your comments directly to the template and submit.
  - You can save and return to your entry anytime during the open comment period.

NOTE

Submitting comments in the tool will require a one-time registration.

Find a video on how to use the commenting tool on the Recurring Stakeholder Processes landing page.