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Renewable Energy Transmission Initiative 2.0
Plenary Report

FINAL REPORT

February 23, 2017

A Report by:

California Natural Resources Agency

With participation by:

California Public Utilities Commission

California Energy Commission

California ISO

Contents

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List of Acronyms

AAEE	Additional achievable energy efficiency
ACEC	Area of Critical Environmental Concern
ARB	California Air Resources Board
BA	Balancing authority
BCN	Baja California Norte
BLM	U.S. Bureau of Land Management
BPA	Bonneville Power Administration
California ISO	California Independent System Operator
CalWEA	California Wind Energy Association
CBI	Conservation Biology Institute
CDFW	California Department of Fish and Wildlife
CFE	Comisión Federal de Electricidad
CNRA	California Natural Resources Agency
COI	California-Oregon Intertie
CPUC	California Public Utilities Commission
CREZ	Competitive renewable energy zone
DAC	Desert Area Constraint
DFA	Development Focus Area
DRECP	Desert Renewable Energy Conservation Plan
DWMA	Desert Wildlife Management Area
E3	Energy + Environmental Economics
EIM	Energy Imbalance Market
ELUTG	Environmental and Land Use Technical Group
EO	Energy only
FCDS	Full Capacity Deliverability Status
FEIS	Final environmental impacts statement
FERC	Federal Energy Regulatory Commission
FMMP	Farmland Mapping and Monitoring Program
GHG	Greenhouse gas
HSR	Hypothetical study range
HVDC	High voltage direct current
IEPR	*Integrated Energy Policy Report*
IID	Imperial Irrigation District
IRP	Integrated resource planning
KGRA	Known Geothermal Resource Area
LADWP	Los Angeles Department of Water and Power
LCGS	Low Carbon Grid Study
LCOE	Levelized costs of energy
LSE	Load-serving entity
NERC	North American Electric Reliability Corporation
NPCC	Northwest Power and Conservation Council
NREL	National Renewable Energy Laboratory
OOS	Out-of-state
OSS	Operating Studies Subcommittee
PG&E	Pacific Gas and Electric Company
POU	Publicly owned utility
PRD	Public Review Draft of RETI 2.0 Plenary Report,
PV	Photovoltaic
RA	Resource adequacy
REAT	Renewable Energy Action Team
RFI	Request for Information
ROW	Right-of-way
RPS	Renewables Portfolio Standard
SCE	Southern California Edison Company
SDG&E	San Diego Gas & Electric Company
SEDA	Solar Energy Development Area
TAFA	Transmission Assessment Focus Area
TANC	Transmission Agency of Northern California
TPP	Transmission Planning Process
TRTP	Tehachapi Renewable Transmission Project
TTIG	Transmission Technical Input Group
VEA	Valley Electric Association
WAPA	Western Area Power Administration
WECC	Western Electricity Coordinating Council
WIEB	Western Interstate Energy Board
WOPR	Western Outreach Project Report

Executive Summary

The Renewable Energy Transmission Initiative 2.0 (RETI 2.0) was introduced in September 2015 in response to Governor Edmund G. Brown Jr.'s Executive Order B-30-015 and the subsequent Clean Energy and Pollution Reduction Act of 2015 (Senate Bill 350, De León, Chapter 547, Statutes of 2015), major policy mandates setting new and ambitious renewable electricity and greenhouse gas (GHG) reduction goals for California.

Joint Agency Leadership

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In response to these new goals – a 50 percent Renewables Portfolio Standard (RPS) and a 40 percent statewide GHG emission reduction from 1990 levels by 2030 – the leaders of the state's energy agencies convened RETI 2.0 to examine where potential new renewable energy generation could be developed and assess what transmission may be needed to deliver this energy to California's load centers. RETI 2.0 revisits the first RETI process in 2009 when state policy makers were considering increasing the state's RPS from 20 to 33 percent.

Purpose

The goal of RETI 2.0 is to update the insights of the first RETI process. This update includes a review of recent data regarding the resource potential, costs and benefits of renewable energy resources in different areas of California and the western United States, and information regarding the ability of the existing bulk transmission capacity to access these resource areas. The project also collects information about new transmission proposals in various stages of development that could help facilitate substantial renewable energy development from various resource areas.

RETI 2.0 also begins to explore the emerging transmission implications of accessing a diverse and balanced renewable energy portfolio and the transmission system needed to accommodate a future electricity system based predominately on renewable energy.

RETI 2.0 is:

- A high-level, non-regulatory review of the utility-scale renewable energy potential in California and the West.
- An overview of environmental issues and assessment of transmission implications and options for developing and delivering renewable energy from different areas.
- A series of "what if" questions.
- Based on existing data and studies.
- Used to inform planning and regulatory processes in 2017 and beyond.

RETI 2.0 is NOT:

- A preference for utility-scale renewable energy over other strategies to meet renewable energy and GHG reduction goals.
- A projection or goal for any total quantity of renewable energy.
- A projection or goal for renewable energy development in any specific areas.
- A projection or goal for any level of additional transmission.
- An endorsement of any specific development proposal, plan, or project.

Process

RETI 2.0 was designed to be a scoping-level identification of the transmission implications and options for accessing high-quality renewable energy resource areas and an overview of the potential energy, environmental, and land-use issues that may need to be addressed if these options are pursued.

The RETI 2.0 followed a three-stage process, culminating with this plenary report:

- **First stage:** The RETI Plenary Group reviewed renewable energy goals and resource potential and identified Transmission Assessment Focus Areas (TAFAs).
- **Second stage:** The three RETI 2.0 input groups reviewed TAFAs and identified transmission, environmental, land-use, and policy issues relevant to developing and transmitting a hypothetical amount of additional renewable energy from each TAFA.
- **Third stage:** In this report, RETI 2.0 staff synthesizes the input group reports, other existing studies, and stakeholder comments in high-level summaries, conclusions, and recommendations.

This assessment differs from traditional procurement and transmission planning that is built around portfolios of incremental renewable resources from many areas. Instead, RETI 2.0 assessed long-term, large-scale development scenarios in individual areas to test the capability of the system and identify potentially major new transmission needs.

The **Transmission Technical Input Group (TTIG)** was composed of all North American Electric Reliability Corporation (NERC)-registered transmission planning entities within California, including staff from each major private and public utility and balancing area.[1] The California ISO led the process, in coordination with the RETI 2.0 agency staff. The TTIG produced a preliminary report in June 2016 describing existing capacity in

RETI 2.0 Organization and Reports*

RETI 2.0 Plenary Group

- Management: California Natural Resources Agency
- Membership: All stakeholders
- Meetings: 4 workshops
- Report: ***RETI 2.0 Plenary Report***

Transmission Technical Input Group

- Management: California ISO
- Membership: NERC-registered transmission planning entities in California
- Meetings: 3 public workshops; weekly group calls
- Report: ***TTIG Transmission Capability and Requirements Report***

Environmental and Land Use Technical Group

- Management: California Energy Commission
- Membership: All stakeholders
- Meetings: 5 public workshops; small group webinars and direct outreach
- Report: ***Environmental and Land Use Information to Support the RETI 2.0 Process***

Western Outreach Project

- Management: Western Interstate Energy Board
- Membership: Western stakeholders
- Meetings: 2 public workshops
- Report: ***RETI 2.0 Western Outreach Project Report***

*All reports available at: www.energy.ca.gov/reti/reti2/documents

[1] The TTIG member organizations include the Sacramento Municipal Utility District, California Independent System Operator, Imperial Irrigation District, Los Angeles Department of Water and Power, Silicon Valley Power, Turlock Irrigation District, Modesto Irrigation District, Western Area Power Administration – SNR, San Francisco Public Utilities Commission, Transmission Agency of Northern California, City of Santa Clara, Pacific Gas and Electric, Southern California Edison, and San Diego Gas & Electric.

the TAFAs and a final report[2] in October 2016 describing the transmission implications of developing hypothetical resource ranges in each TAFA, and identified potential transmission constraints and conceptual solution, where applicable.

The **Environmental and Land Use Technical Group (ELUTG)**, led by California Energy Commission staff, was an open stakeholder forum charged with collecting and assessing existing environmental and land-use planning information relevant to renewable energy and transmission planning, including consultation with Native American tribes. The ELUTG final report[3] was published November 9, 2016.

The **Western Outreach Project and Report (WOPR)** was an initiative led by Western Interstate Energy Board staff at the request of California RETI 2.0 agencies, with technical support from Energy Strategies LLC. The Western Outreach Project, initiated in August and completed in October 2016, developed a series of outreach questions regarding renewable resource potential, costs, and locations; the capability of the existing transmission system to deliver these resources to California load centers (and allow for export of California renewable energy); and the potential for new transmission proposals to expand this capacity. Western Interstate Energy Board (WIEB) staff held two workshops to explore these questions in Portland, Oregon, and Las Vegas, Nevada. A summary report was published October 28, 2016.[4]

In this plenary report, the RETI 2.0 process culminates in TAFA assessment summaries, high-level conclusions, and recommendations for further work. These summaries, conclusions, and recommendations were originally proposed in a public review draft (PRD) in December 2016 and have been supported or modified in response to comments received since then.

Potential Applications

The summaries, conclusions, and recommendations in this plenary report are intended to inform future state regulatory and policy proceedings and may be useful to renewable and transmission developers, environmental and community groups, and local, regional, and federal government entities. These potential applications include the following:

- **TAFA assessment summaries** (Part 2 and Appendix A) are informational and may be used to inform commercial development interest; suggest local, state, and federal land-use planning needs; and refine regulatory and utility energy and transmission planning assumptions.
- **Potential Transmission Constraints and Conceptual Solutions** (Part 3) are intended to inform local, state, regional, and federal planners and policy makers about geographic areas where further energy, environmental, land-use, and transmission planning may be required in the next 15 years.
- **Scenario Concepts to Inform Resource and Transmission Planning** (Part 4) are designed to help shape modeling scenarios to be used in resource planning at the CPUC and transmission planning by the ISO.

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[2] RETI 2.0 Transmission Technical Input Group, *Transmission Capability and Requirements Report*, Renewable Energy Transmission Initiative 2.0, October 24, 2016, http://docketpublic.energy.ca.gov/PublicDocuments/15-RETI-02/TN214168_20161025T091645_Transmission_Capability_and_Requirements_Report.pdf.

[3] RETI 2.0 Environmental and Land Use Technical Group, *Environmental and Land-Use Information to Support the Renewable Energy Transmission Initiative (RETI) 2.0 Process,* California Energy Commission, Report CEC-700-2016-007, November 2016, http://docketpublic.energy.ca.gov/PublicDocuments/15-RETI-02/TN214445_20161109T100524_Environmental_and_Land_Use_Information_to_Support_the_Renewable.pdf

[4] Western Interstate Energy Board, *RETI 2.0 Western Outreach Project Report,* Prepared by Energy Strategies, LLC; October 28, 2016 (revised version), http://docketpublic.energy.ca.gov/PublicDocuments/15-RETI-02/TN214339_20161102T083330_RETI_20_Western_Outreach_Project_Report.pdf.

They may also inform the resource and transmission planning of the POUs, regional transmission studies by WECC, and interregional transmission planning under FERC Order 1000.

- **Environmental, Cultural, and Land-Use Recommendations** (Part 4) are directed primarily toward the ongoing energy planning and policy functions of the Energy Commission, in coordination with environmental stakeholders, tribal entities, county officials, and energy sector regulators.

While the RETI 2.0 process has been designed to inform a range of potential policy, planning, and commercial applications, RETI 2.0 is non-regulatory, and this report and the other products of the RETI 2.0 process will not be directly adopted within any individual regulatory process. Stakeholders are encouraged to identify and advocate for opportunities to incorporate these conclusions and recommendations in appropriate proceedings.

Planning Goals and Resource Potential

The RETI 2.0 Plenary Group's review of 2030 renewable energy goals incorporated projections of the potential renewable energy needed to meet both a 50 percent RPS, as well as meeting GHG emission reduction targets commensurate with a 40 percent statewide reduction from 1990 levels. These projections are informational only and do not represent a regulatory decision or recommendation.

The group used a variety of sources to quantify a wide range of potential incremental renewable energy need (that is, beyond the energy needed to meet the 33 percent RPS standard in 2020), shown in Table ES-1 below. The table reports estimates based on two of these sources:

- California Energy Commission's 2015 *Integrated Energy Policy Report* (2015 IEPR) Energy Demand Forecast, extrapolated to 2030 and adjusted to approximate SB 350 energy efficiency goals.[5]
- California PATHWAYS modeling project performed for California agencies by Energy + Environmental Economics (E3) in 2014-2015.[6]

Table ES-1. Summary of Planning Goals and Scale of Renewable Energy Needed

Electricity Demand (TWh)		**IEPR Low Demand**	**IEPR Mid Demand**	**IEPR High Demand**	**PATHWAYS Straight-Line**	**PATHWAYS Early Deployment of Electrification**
2020 Retail Sales		237	247	257	—	—
2030 Retail Sales		206	243	276	268	317
Renewable Energy Needed (TWh)						
33% RPS 2020		78	82	85	83	83
50% RPS 2030		103	122	138	134	159
50% RPS by 2030, Incremental to 2020	**Renewable Energy Needed (TWh)**	**25**	**40**	**53**	**51**	**76**
	New Capacity Needed (MW) (30% Cap. Factor)	**9,400**	**15,200**	**20,300**	**19,600**	**29,000**

Sources: RETI Planning Goals Summary (5/2/2016) and E3, Estimating Renewable Energy Needs for RETI 2.0 (4/19/2016).

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[5] Cary Garcia, California Energy Commission. "California Energy Demand Forecast for RETI 2.0," January 29, 2016.

[6] Energy + Environmental Economics (E3). "Estimating Renewable Transmission Needs for RETI 2.0," April 19, 2016.

In reviewing these potential renewable energy needs, many stakeholders commented on the complexity of factors affecting energy demand generally and utility-scale renewable energy specifically. Both RETI 2.0 agency staff and stakeholders emphasized that state policy makers, utilities, and consumers have a wealth of strategies available to meet RPS targets and reduce GHG emissions. Although this report focuses on transmission needs to access and integrate utility-scale renewable energy, utility-scale renewable energy is not the only solution to meeting California's goals, and new transmission is not the only solution to accessing utility-scale renewable energy.

Summary of Resource Conclusions:

Renewable energy demand: In addition to demand forecasts, the Plenary Group reviewed the drivers and uncertainties of renewable energy demand forecasts.

- There is a wide range in forecasts of potential future need for utility-scale renewable generation by California utilities to meet 2030 goals.
- High energy-efficiency, high distributed-energy-resource scenarios may reduce the need for utility-scale renewable energy, which may reduce the need for additional bulk transmission.
- Large load-serving entities (LSEs) may already have sufficient renewable energy under contract to meet RPS obligations through the mid-2020s or beyond. However, the SB 350 mandate to meet GHG targets, the ongoing reduction in renewable energy capital costs, the (near-term) availability of federal tax credits, and the growth of CCA and corporate buyers will also impact the scale and timing of non-RPS demand.

Renewable energy potential: The Plenary Group reviewed renewable resource costs and values in California, focusing on long-term trends and potential from the current year to 2030.

- Low-cost, utility-scale solar photovoltaic (PV) is cost-competitive across much of California.
- Many of the highest-quality wind resources in California have already been developed or are constrained by environmental and permitting barriers. However, wind turbine technology improvements allow for a greater range of wind resources to be developed cost-effectively.
- Geothermal technologies have made important strides in development cost reduction and generation flexibility, and development in the Salton Sea area offers important co-benefits.
- Substantial high-quality out-of-state renewable energy resources are under active development.

Optimized portfolio issues: The Plenary Group also reviewed recent studies examining potential large-scale portfolios of renewable resources for California from 2026 to 2030 and found that:

- Without integration solutions, continued growth in solar PV resources will lead to increased costs from a surplus of generation during high solar periods and a shortage of system and flexible capacity at other times.
- Technology and geographic diversity of renewable resources can reduce these costs by decreasing curtailment and increasing system capacity and (potentially) flexible capacity.
- Access to low-cost renewable energy resources both within California and out of state, especially wind and geothermal resources with generation profiles complementary to California solar generation, as well as access to energy markets outside California, can increase the diversity of renewable resources, provide markets for excess generation, and reduce ratepayer costs.

Transmission Assessment Focus Areas

The Plenary Group identified potential renewable resource areas within California, import-export paths, and areas outside California, referred to as "Transmission Assessment Focus Areas" (TAFAs), for further assessment by environmental, land-use, and transmission experts. Part 2 of this report describes this process and summarizes information and conclusions about the transmission, environmental, and land-use implications of development in each TAFA and import-export path. Appendix A provides detailed information about each area. Tables ES-2 and ES-3 below summarize the existing generation and transmission capacity and development proposals in each TAFA.

Table ES-2. Summary of Existing and Proposed TAFA Generation and Transmission

Transmission Assessment Focus Area (TAFA)	Renewable Generation (from CEC REAT database)		Estimated Existing Transmission Capacity	
	Existing Online (MW)	Approved Projects (MW)	Full Capacity Deliverability (MW)	Energy Only (MW)
Lassen/Round Mountain	229	58	0	1,250
Sacramento River Valley	460	135	Unknown	2,100
Solano	1,934	167	Unknown	880
San Joaquin Valley	1,952	6,030	1,823	3,131
Tehachapi	5,345	4,120	4,500	5,600
Victorville/Barstow	302	344	1,900*	3,300
Riverside East	1,296	2,275	2,450**	4,754
Imperial Valley	2,079	1,349	523(1); 2,300(2)	1,849

*Victorville Full Capacity is subarea specific. **Transmission capability provided for the Riverside East TAFA is based on the additional capacity provided by the West of Devers Upgrade Project as proposed by SCE and approved by the CPUC on August 18, 2016.

(1) Per California ISO, this number is subject to change. The ISO 2016-2017 Transmission Plan will update information regarding additional deliverability expected to be available for IID and ISO connected Imperial area generation.

(2) Per IID, Imperial Valley North Full Capacity Deliverability is 1,100 MW and Imperial South Full Capacity Deliverability is 1,210 MW.

Table ES-3. Summary of TAFA Transmission Path Data

Import/Export Path	WECC Path Rating (MW Import)	Estimated Incremental Capacity Inside CA	Aggregate Capacity of Transmission Proposals for Delivery Through This Import Point
Path 66 (COI)	4,800	0 MW	0 MW
Path 76 (Alturas)	Not rated	0 MW	500 MW
Path 24 (Tahoe)	Not rated	0 MW	0 MW
Path 52 (Owens Valley)	Not Rated	0 MW	500 MW
Path 46 (Eldorado)	10,623 (combined)	5,500 to 8,500 MW (Desert Area Constraint)	7,500 MW
Path 46 (Palo Verde)			5,000 MW
Path 45 (Baja Norte)	800	523 MW	300 to 600 MW

Sources: WECC; TTIG; and WOPR.

Potential Transmission Constraints and Conceptual Solutions

The TTIG and RETI 2.0 stakeholders identified several potential transmission constraints in California and along the major import-export paths that could limit the delivery of additional renewable energy. The TTIG, RETI 2.0 stakeholders, and the RETI 2.0 staff identified several conceptual options that could mitigate these constraints, including new transmission, advanced technologies and non-wire alternatives, and operational efficiencies. These potential constraints and conceptual solutions are identified below, and Part 3 discusses these potential constraints and solutions in detail.

California-Oregon Intertie

- The California-Oregon Intertie (COI) consists of three 500 kilovolt (kV) transmission lines with a rated capacity of 4,800 megawatts (MW) connecting the Pacific Northwest and Northern California.
- There is currently no existing capacity available for new fully-deliverable resources from either generation in Northern California or imports from the Northwest.
- Providing new capacity could require new transmission from the Oregon border to the Tracy area, at an order-of-magnitude cost[7] of $2 billion-$4 billion.
- Capacity on the COI could potentially be increased through advanced transmission technologies or new transmission elsewhere in the Western Interconnection to reduce regional loop flow. [8]
- Operational improvements – scheduling coordination and dynamic line rating – could increase the utilization of existing capacity.

San Joaquin Valley

- The hypothetical study range of 5,000 MW would trigger a need for substantial upgrades to the 115 kV or 230 kV network, at an estimated order-of-magnitude cost of $400 million-$500 million.
- If a large quantity of new generation could be geographically concentrated and connected to the 500 kV system, it could potentially offer lower cost and greater system benefits.
- RETI 2.0 stakeholders also suggested that the San Joaquin Valley constraints could be an appropriate application of advanced technologies like power flow control.[9]

Desert Area Constraint

- The Desert Area Constraint is a transmission constraint that affects deliverability of new renewable generation from a vast area, including the Victorville-Barstow, Riverside East, and Imperial Valley TAFAs, as well as imports from the Eldorado or Palo Verde import-export paths.
- This constraint can take different forms – triggered by different contingencies and limiting facilities – depending on the resource development mix from different areas.
- The California ISO, Southern California Edison, and Los Angeles Department of Water and Power (LADWP) are currently coordinating to address the most critical of these limitations – an upgrade of the Lugo-Victorville 500 kV line at an approximate cost of $34 million.
- The second constraint arises at an incremental level of generation of as little as 2,000-4,000 MW (if concentrated in Riverside East) or as high as 5,500 to 8,500 MW (from all affected TAFAs combined).

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[7] *Order of magnitude cost* is a cost estimate classification typically used at the screening or feasibility level of a project and is a conceptual estimate.

[8] *Loop flows* are generally defined as unscheduled electricity flow in one transmission system caused by scheduled flows in a neighboring system. Loop flows can increase congestion and costs in the affected transmission system.

[9] *Power flow control devices* help relieve constraints in a transmission network by directing power flow away from over-utilized lines and toward under-utilized lines.

- Possible solutions for this limitation could include ***either*** a new series compensated 500 kV line between Mira Loma substation in the Inland Empire and the Red Bluff substation near Desert Center ***or*** a new 500 kV line between Lugo and Eldorado substations. Either of these projects could have significant permitting challenges and an order-of-magnitude cost of $1 billion.
- Power flow control technology and advanced conductors could increase capacity, and new transmission elsewhere (for example, Imperial Valley) could provide partial solutions.

Imperial Valley

- The constraints to delivering additional renewable resources from (and through) the Imperial Valley include both physical and accounting issues. RETI 2.0 focused solely on physical transmission capacity.
- Transmission constraints to delivery of an additional 5,000 MW include the ECO- Miguel line to the west of Imperial Valley and Path 42 to the northwest between Imperial and Coachella Valleys.
- Six conceptual transmission proposals were identified by TTIG members that could allow for increased energy export from (and through) the Imperial TAFA. These projects may also provide reliability benefits to the southwest United States and improve import and export capability to Arizona, New Mexico, and Baja California Norte.
- Generation in Imperial Valley would also contribute to the Desert Area Constraint.
- The Imperial Valley may be an application for advanced technologies including high voltage direct current (HVDC) and flow control.

North of Kramer

- Generation development north of the Kramer substation (San Bernardino County) could result in constraints between Kramer, Lugo, and Calcite substations.
- These constraints could be mitigated with upgrades such as a teardown and rebuild of the Calcite-Lugo 220 kV line, a new Lugo 500/220 kV transformer bank, and either a new Coolwater-Lugo 220 kV line or a new Kramer-Llano 500 kV line.
- Stakeholders suggested that power flow control technologies could also assist in this area.

The Central and Northern Sierra Paths

- These three interconnections to Nevada are each relatively weak and would require new capacity.
- The Lassen Municipal Utility District has proposed a new line to connect Path 76 (Reno-Alturas) to the COI, but the line would face extensive permitting challenges, and energy delivery would still be subject to the existing constraints on the California-Oregon Intertie.
- An upgrade of Path 24 between Truckee and Reno would be subject to extensive environmental constraints.
- A conceptual project to add between 750 and 1,000 MW capacity to Path 52 in Owens Valley was suggested by a Nevada study in 2012 at an approximate cost of $600 million.

Scenario Concepts to Inform Resource and Transmission Planning

As part of SB 350, California's utilities are required to prepare integrated resource plans (IRPs) that meet both RPS and GHG reduction goals.[10] The investor-owned utilities' (IOUs) IRPs will be guided by scenario planning at the CPUC to "identify a diverse and balanced portfolio of resources … that provides optimal integration of renewable resources."[11] These scenarios, the utilities' IRPs, and the associated projections

[10] Public Utilities Code Sections 454.52(a)(1) and 9621(b).

[11] Public Utilities Code Section 454.51(a).

of future renewable resource portfolios will in turn shape the policy scenarios used in the California ISO's annual Transmission Planning Process (TPP).

The RETI 2.0 process looked at renewable energy resource development and transmission implications on a TAFA-by-TAFA basis but did not develop any specific aggregate portfolios of resources. However, the assessment of transmission implications identified several issues that are apparent only when considering the combined effects of development in several areas. These transmission implications could be examined through scenarios developed for the CPUC's IRP proceeding and those that will be used in the California ISO's TPP. The following scenario concepts are derived from issues discussed during the RETI 2.0 process, and have been refined by the Plenary Group through feedback on the PRD.

Existing Capacity Scenario Concepts

The results of the RETI 2.0 assessment confirm that existing transmission capacity is able to interconnect a substantial amount of new renewable generation in several areas of the state. Among the TAFAs reviewed by the TTIG, more than 10,000 MW of capacity was found to be available for resources seeking full capacity deliverability status (FCDS),[12] or more than 23,000 MW of capacity available for generation not seeking resource adequacy value, or "energy-only" (EO)[13] status.

However, the ability to access different types of renewable energy resources, the value they provide to the electricity system, and the total quantity of energy resources that can be delivered depend on how this existing capacity is allocated in specific transmission areas. The PRD proposed that the planning agencies (CPUC, Energy Commission, and ISO) examine these issues with scenarios that test different renewable energy portfolios against a different mix of deliverability status in each area, and the effect on the total transmission need.

Commenters to the PRD supported the examination of these issues. One opportunity may be in the "40 X 30 Reference Scenario" being developed within the IRP proceeding at the CPUC. As of December 2016,[14] staff at the CPUC is developing a proposed modeling framework that optimizes each year's procurement of renewable resources based on minimizing the total costs and benefits of the entire resource portfolio over a 20-year planning horizon. These costs and benefits include the RA and capacity values, and the costs of EO and FCDS delivery status. This model framework could provide insight into the most efficient use of transmission deliverability, among other values.

Desert Area Constraint Scenario

The RETI 2.0 assessment results show the Desert Area Constraint may be a binding constraint on meeting California's 2030 RPS and GHG goals. The areas contributing to this constraint contain some of

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[12] A California ISO FCDS transmission interconnection provides a reasonable assurance that a generator's dependable capacity can be delivered to load under contingency conditions simultaneously with all other dependable generation in the same general area at peak load conditions. Transmission upgrades may be required to allow a generator to be available at system peak load during contingency conditions, so that it can be counted in the CPUC's Resource Adequacy (RA) program. While deliverability reduces the likelihood of curtailment, there is no assurance -- other resources or imports may be more economical and get dispatched in the market instead.

[13] A California ISO EO interconnection allows a generator to deliver energy when transmission is available, but does not provide deliverability status as determined by the ISO; therefore, the generator cannot be counted in the CPUC's RA program. Deliverability is determined by the ISO according to a contingency-based study and, therefore, is not related to the likelihood of curtailment under typical operating conditions.

[14] E3, "Resolve Modeling Overview," CPUC IRP Workshop, December 16, 2016.

the highest energy resource potential, commercial interest, and advanced planning examined in RETI 2.0. Specific conceptual solutions were identified to relieve this constraint, and other projects (such as, advanced transmission technologies[15] or new transmission to address Imperial Valley deliverability) could also have benefits.

Given the complexity of issues in the area and the long lead times typically associated with transmission permitting and approvals, RETI 2.0 participants and commenters to the PRD supported further study of the DAC and potential solutions. Although the RETI 2.0 project did not develop specific portfolios to study, the commercial interest and environmental feasibility information received during RETI 2.0 suggest several plausible portfolios of generation in different areas and imports that could be used to test constraints and solutions.

Out-of-State Transmission Scenario Concepts

Both the TTIG process and Western Outreach Project identified substantial interest and activity in out-of-state (OOS) transmission development. The WOPR identified 12 OOS transmission project proposals that cite among the associated benefits the delivery of OOS renewable energy resources to load in California. These projects combine into a number of potential transmission configurations that offer a variety of potential benefits, including access to a diversity of high-quality renewable resources, markets for California's excess renewable energy, and reduced congestion costs within California. The WOPR also noted the OOS transmission may pose potential opportunity costs or option value.

These broader system implications of these configurations are not captured by the current procurement cost model used in the CPUC RPS Calculator. With the advent of IRPs, the CPUC, utilities, and California ISO have an enhanced opportunity to evaluate the potential benefits of regional transmission expansion. For these reasons, the PRD proposed that CPUC and California ISO planning processes could include one or more scenarios, using data collected in the WOPR, to represent potential OOS transmission configurations in forthcoming IRP "40 x 30" studies.

Multiple commenters to the PRD strongly supported further examination and inclusion of OOS system capabilities in IRP scenarios and suggested a broader array of aspects to consider in any scenario. Among these are a more detailed model of the availability of existing transmission, through transmission service agreements like conditional firm transmission and dynamic scheduling, and additional latent transmission capacity that may be created by the retirement of coal generation facilities.

Information on Western Renewable Power Costs

Recognizing the historical lack of project-specific and commercial-quality renewable resource cost information from around the West, including the costs and capability of transmission offered to deliver renewable energy resources to California, the WOPR recommended that California agencies and utilities consider a request for information (RFI) process to solicit commercial information from both out-of-state generation and transmission developers. Commenters to the PRD, however, were generally skeptical such an exercise would achieve the necessary buy-in from developers and utilities. Several commenters did support, however, a more multilateral approach to generating data from existing sources and direct engagement between utilities, such as in the Resource Planners Forum, described below.

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[15] *Advanced transmission technologies* generally refers to advanced conductors, high voltage direct current, flexible AC, and flow control technologies

Regional Resource Planning Collaboration and Market Facilitation

The Western Outreach Project participants expressed appreciation for the value of regional collaboration and identified several topics that would benefit from further coordination. Two specific types of expanded coordination opportunity were identified: regional resource planning collaboration and power market and transmission service product innovations.

Resource Planning Collaboration

The WOPR identified several topics that would benefit from collaboration among resource planners in the region. A central topic was identifying opportunities to leverage predictable shortage or surplus positions among utilities, especially those created by different renewable energy portfolios. Other topics include exploring the impact of anticipated coal plant retirements on regional transmission capacity and stability. The WOPR suggested that WIEB could reconstitute the Resource Planners' Forum for this purpose and that California resource planners should participate.

Regional Market Facilitation

The WOPR also recommended that western energy marketers, transmission owners, developers, utilities and other stakeholders convene a series of technical forums to innovate power market products and transmission service agreements. These forums would help identify, develop, standardize, and promote products and agreements that could help increase renewable energy trading and transmission utilization. Potential power market products include short-duration schedules such as "duck-belly" (midday oversupply) and "duck-neck" (evening ramping need), and transmission products include conditional firm transmission service and dynamic scheduling between balancing areas. Such an initiative would expand the use of these tools to make better use of existing transmission, improve integration of renewable energy, and lower costs of renewables deployment. WIEB could convene these forums, as could the Western Systems Power Pool or other appropriate public or private body.

Environmental, Cultural, and Land-Use Data

Environmental

The RETI 2.0 TAFA assessments presented in this report rely on known environmental information and do not present new data. The ELUTG report recommends that RETI 2.0 fill biological and ecological data gaps for evaluating potential environmental implications at a high planning level. The report recommends that the state consider creating planning information through data logic models that can assess areas for potential environmental implications at a landscape-scale level. The completion of a fully functional environmental report writer tool, as described in the ELUTG report, could provide a viable way to quickly and effectively use the existing data sets to evaluate potential new renewable energy resource and transmission development areas in a variety of infrastructure-planning processes.

Tribal and Cultural Resources

Energy Commission staff observes that while early tribal consultation for planning purposes is required by Executive Order B-10-11 and Natural Resources Agency tribal consultation policy, the maximum benefits of consultation result from providing tribes with specific information to which they can respond. Upcoming transmission and renewable energy planning processes will include continued consultations with tribes and tribal communities. Energy Commission staff is planning a statewide Tribal Energy Summit in 2017, where statewide energy planning and energy development considerations on tribal lands will be discussed. Specific project concerns and impact assessments will continue to be discussed among tribes and state energy agencies on a project-by-project basis as required by the California Environmental Quality Act.

County Land-Use Planning

When feasible, future high-level planning for renewable energy and transmission should continue to include local land-use information. Such information should be gathered through an iterative process with counties to ensure that the information accurately reflects county land-use rules and policies. The energy agencies should continue to assist counties with local land-use planning that facilitates renewable energy and transmission development by providing data and tools to assist with planning, decision making, and stakeholder engagement.

Part 1. California's Climate and Renewable Energy Goals

RETI 2.0 Policy Context, Process, and Goals

California has set some of the most ambitious goals for renewable energy deployment and GHG emission reductions in the nation and the world. With the passage of the Clean Energy and Pollution Reduction Act (Senate Bill 350, De León, Chapter 547) in 2015, the state committed to serve 50 percent of retail electric load with qualifying renewable energy[16] by 2030. With Senate Bill 32 (Pavley, Chapter 249) in 2016, the state tightened its GHG reduction goals to a 40 percent decrease from 1990 levels by 2030, a goal that is likely to require significant changes across California, including significant new electric uses and the need for a largely carbon-free electricity supply.

Thus, a major new focus for the electric sector — including generators, load-serving utilities, regulators, and consumers — is accessing and integrating large quantities of carbon-free electricity to meet these goals. The bulk electric transmission system is also expected to play a critical role in accessing and integrating higher levels of cost-effective renewable resources. While a variety of strategies, from energy storage to demand response,[17] will be important to managing California's future majority-renewable electric grid, studies reviewed during RETI 2.0 indicate that one of the most cost-effective and large-scale strategies involves connecting geographically diverse renewable resources and energy demand centers through a more robust regional transmission network.

Moreover, because transmission often involves high capital costs, environmental and economic implications, and long planning time frames, a long-term strategic approach is warranted. Without proactive decision-making, important options for reaching California's goals at the lowest cost may simply be lost due to inadequate lead time. It is for these reasons that meeting the SB 350 RPS and SB 32 GHG targets requires a focus on electric transmission – making the best use of existing transmission and identifying where new transmission is necessary.

Electric Transmission Infrastructure Development in California

The transmission development process is long, complex, and expensive. Moreover, there can be a mismatch between planning and procurement for generation resources and the planning and approvals for transmission. Transmission developers rely on financial commitments from generators, who in turn rely on power purchase agreements from utilities – agreements utilities are often hesitant to sign without adequate transmission for delivery. A seven-to-thirteen-year time frame for developing transmission is generally planned, and often financed, based on power procurement decisions that are developed on a timescale of two to five years. In addition, there is an aggregation problem in accessing geographic areas with high-quality, cost-effective renewable resources. While it might be most cost-effective to build transmission for the "ultimate buildout" of renewable resources in an area, rarely is any one developer or off-taker able to support this cost-effective "right size."[18]

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[16] RPS-eligible renewables do not include large hydroelectric facilities and most behind-the-meter systems.

[17] For an overview of operational strategies to integrate high levels of renewables, see *Teaching the "Duck" to Fly,* Second Edition. Lazar, J. (2016). Montpelier, VT: The Regulatory Assistance Project. Available at http://www.raponline.org/document/download/id/7956.

[18] Transmission right-sizing was first discussed in the *2011 IEPR* (pp. 38). It was raised by stakeholders in the *2014 IEPR Update* (pp. 153-154) and included as a recommendation in the *2015 IEPR* (pp. 97-98, 101). These reports are available at http://www.energy.ca.gov/energypolicy/.

California utilities and planning agencies have adopted several processes to address these issues. For the California ISO region, the CPUC and Energy Commission collaborate to identify plausible portfolios of renewable energy resources for the California ISO to use in transmission planning on a 10-year horizon. Between planning regions, the FERC Order 1000 process supports collaboration in transmission projects. The nascent IRP process in California also provides a venue for considering long-term infrastructure needs.

The RETI 2.0 initiative seeks to complement these efforts with a broad, long-term look at California's 2030 renewable energy goals. The initiative examines geographic areas where large-scale renewable resource potential, commercial interest, and environmental feasibility converge and then identifies where and what kind of transmission may be necessary to access and integrate them.

Relationship to Other Proceedings

The RETI 2.0 project is a non-regulatory, high-level planning project intended to inform the regulatory processes of the state's energy agencies, as well as other public and private planning and resource decisions. Because RETI 2.0 relies on existing information and expert opinion, the data gathered and conclusions reached are intended to suggest direction for these proceedings by identifying data sources that should be incorporated and scenarios for further study.

Three major cyclical processes form the core of California's electric infrastructure planning:[19]

- Long-term forecast of energy demand produced by the Energy Commission as part of its biennial *Integrated Energy Policy Report (IEPR)*.
- Integrated resource planning (IRP) conducted by each load-serving entity (LSE), with oversight from the CPUC or the Energy Commission.
- The annual Transmission Planning Process (TPP) performed by the California ISO, or equivalent processes by the state's other balancing authorities.

These processes are being transformed by the IRP framework mandated by SB 350 to help formalize the consideration of greenhouse gas emissions reduction objectives and to look farther than California's typical 10-year planning horizon. Following the passage of SB 350, California's LSEs will begin in 2017 to prepare long-term IRPs encompassing multiple policy objectives, including the 50 percent RPS and 40 percent GHG reduction goals by 2030.

Elsewhere in SB 350,[20] the California Air Resources Board (ARB), in consultation with the Energy Commission and CPUC, is charged with establishing GHG reduction targets for the electricity sector to be used in IRP planning. The ARB is developing GHG emission projections through an economy-wide regulatory roadmap and modeling exercise called the 2017 Scoping Plan Update.[21]

While the Energy Commission will review the IRPs of California's publicly owned utilities, the CPUC will have a more extensive role in developing guidance for the IOUs' IRPs — including identifying "a diverse and balanced portfolio of resources needed to ensure a reliable electricity supply that provides optimal

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[19] Alignment of Key Infrastructure Planning Processes by CPUC, CEC and CAISO Staff (December 23, 2014). http://www.energy.ca.gov/assessments/documents/CEC-CPUC-ISO_Process_Alignment_Text.pdf.

[20] Public Utilities Code Section 454.52(a)(1)(A).

[21] ARB. *The 2017 Climate Change Scoping Plan Update: The Proposed Strategy for Achieving California's 2030 Greenhouse Gas Target* (1/20/2017).

integration of renewable energy in a cost-effective manner… and designed to achieve any statewide GHG emissions limit established pursuant to the California Global Warming Solutions Act of 2006."[22]

The process by which GHG targets are set and used in IRP planning is being developed in an interagency process and will be decided by the CPUC and Energy Commission in 2017. In November 2016, CPUC staff published a white paper proposing how the GHG planning targets could be used to guide IRP planning:

> *It is expected that the electricity-sector [GHG] target will be designed as a planning goal for IRP. Specifically, staff proposes that IRP modeling will incorporate certain assumptions or constraints on cost, reliability, and GHG emission reductions, and the CPUC will generate multiple portfolios and select a single one to represent the Reference 40% by 2030 Plan (or "Reference System Plan"). The Reference System Plan would then be used to guide investment, resource acquisition, and programmatic decisions to reach the state's policy goals, in addition to informing the development of individual LSE IRPs.*[23]

It is also anticipated that IRP planning will affect the ISO's annual Transmission Planning Process. The ISO has historically relied on the CPUC and Energy Commission to annually communicate specific renewable energy portfolios and other grid-scale resource forecasts necessary to meet state policy goals, to guide the ISO's "public-policy-driven" transmission needs assessment.

Procedural Steps for the CPUC Proposed IRP Approach

- Step 1: ARB develops range of GHG emissions for the electric sector, from economy-wide GHG assessment.
- Step 2: CPUC generates explores scenarios and identifies a "40 x 30 Reference Plan" to guide IRP development by LSEs.
- Step 3: CPUC issues specific IRP guidance to LSEs.
- Step 4: Each load-serving entity prepares an IRP.
- Step 5: CPUC reviews, approves, or rejects IRPs.
- Step 6: CPUC approves any incremental resource procurement requested by IRPs.

These aspects of the new SB 350 IRP planning framework— portfolio optimization, decreasing GHG emissions toward a specific goal, and a statewide, all-source, long-term investment perspective — create new opportunities for planning to address the infrastructure challenges of renewable energy resource development and integration, including transmission and energy storage.

The RETI 2.0 process is designed to inform each of these processes, including by comparing long-term RPS and GHG reduction goals, exploring the availability of renewable energy and other grid-scale resources, and identifying potential transmission constraints and conceptual solutions. However, RETI 2.0 is non-regulatory, and this report and the other products of RETI 2.0 will not be directly adopted within any individual regulatory process. Instead, the information, insights, conclusions, and recommendations presented during the RETI 2.0 process are intended to be used by stakeholders, staff, and decision-makers to inform proposals and guide next steps. Stakeholders are encouraged to identify and advocate for opportunities to incorporate these conclusions and recommendations in appropriate proceedings.

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[22] Public Utilities Code Section 454.51(a).

[23] CPUC Staff White Paper. *Implementing GHG Planning Targets in the Integrated Resource Planning (IRP) Process* (11/15/2016).

Overview of RETI Process

The RETI 2.0 was designed to be a high-level review of existing and recent work. The process is also a scoping-level identification of transmission implications and options for accessing areas with concentrations of high-quality renewable resources, and the resource, environmental, and land-use issues that may need to be addressed if these options are pursued. To accomplish this goal, the RETI 2.0 staff followed a three-part process:

- **First stage:** The RETI Plenary Group reviewed renewable energy goals, renewable resource potential, and balanced portfolio needs and identified TAFAs for further assessment.
- **Second stage:** The three RETI 2.0 input groups (TTIG, ELUTG, and Western Outreach Project) reviewed and identified transmission, environmental, land-use, and policy implications relevant to developing and transmitting a hypothetical study range of additional renewable energy from each TAFA.
- **Third stage:** The RETI 2.0 staff synthesized the input group reports, and other existing studies, and proposed conclusions and recommendations. The RETI 2.0 Plenary Group discussed proposed conclusions, recommendations, and potential next steps.

The RETI 2.0 Plenary Group reviewed renewable energy goals during a workshop in January 2016 that incorporated review of the Energy Commission's demand forecast, CPUC renewable energy need projections, POU demand and renewable energy forecasts, model results from the ARB's *Climate Change Scoping Plan*, the E3 PATHWAYS model, and demand and renewable energy projections from the Western Electricity Coordinating Council. In March, the Plenary Group reviewed recent data regarding costs and benefits of renewable technologies and commercial interest in different areas around the state and West in a workshop featuring more than 20 presentations from renewable resource developers and procurement planners. In April, the group convened a workshop to examine existing studies of renewable resource scenarios and portfolios in 2030 and the implications for planning for optimal portfolios under SB 350 and the IRPs.

The information in these workshops led directly to the identification of TAFAs in May 2016. These TAFAs identified both specific geographic areas with substantial renewable resource development or trade potential. The TAFAs were then assigned a "hypothetical study range," a purely notional, yet plausible, quantity of long-term future additional renewable generation or imports for the RETI 2.0 Input Groups to consider and respond to. In effect, the Plenary Group asked the input groups to respond to a series of "if-then" questions, such as "If 5,000 MW of additional renewable resource capacity were to be developed in the Riverside East TAFA, what would be the transmission, environmental, and land-use implications?"

The three input groups pursued these questions in separate tracks between May and October, with each final report submitted in late October and November. RETI 2.0 staff and technical consultants at Aspen Environmental Group then synthesized the information and recommendations of these input group reports, along with Plenary Group workshops, stakeholder comments, and other existing studies and planning exercises, to summarize potential environmental and land-use issues, identify potential transmission constraints and conceptual solutions, and propose potential next steps and recommendations.

These draft summaries, conclusions, and recommendations were published in a public review draft (PRD) of this report on December 16, 2016. Following a public workshop and comment period, roughly three dozen comments were received expressing support or opposition or proposing edits to the PRD. These edits have been incorporated into this final plenary report and Appendix A.

Renewable Energy Goals – From 2020 to 2030

The RETI 2.0 process began with a review of California's renewable energy planning goals and an assessment of the value of the renewable energy resources that could be available to achieve those goals. This exercise provided a "ballpark" or "bookended" range of total resources that could be required under a variety of scenarios. This range provided a basis for guiding the scale of the assessments completed under RETI 2.0, but the range has no regulatory weight or status.

Energy Demand Forecasting

The overall energy demand, renewable energy demand, and GHG reduction forecasts used by RETI 2.0 come from the following two primary data sources:

- California Energy Commission's 2015 IEPR Energy Demand Forecast, extrapolated to 2030 and adjusted to approximate SB 350 energy efficiency goals.[24]
- California PATHWAYS modeling project performed for California agencies by Energy + Environmental Economics (E3) in 2014-2015.[25]

Integrated Energy Policy Report

Senate Bill 1389 (Bowen, Chapter 568, Statutes of 2002) requires the Energy Commission to prepare a biennial *Integrated Energy Policy Report* (*IEPR*) that assesses major energy trends and issues facing the state's electricity and other energy sectors and provides policy recommendations to conserve resources; protect the environment; ensure reliable, secure, and diverse energy supplies; enhance the state's economy; and protect public health and safety.[26]

The Energy Commission prepares these assessments and associated policy recommendations every two years, with updates in alternate years. Preparation of the *IEPR* involves close collaboration with federal, state, and local agencies and a wide variety of stakeholders in an extensive public process to identify critical energy issues and develop strategies to address those issues. As part of the *IEPR,* the Energy Commission adopts the California Energy Demand Forecast, which forecasts electricity demand over a 10-year time frame. The California Energy Demand Forecast is used by both the CPUC and California ISO in their respective planning processes to ensure consistency and eliminate redundancy in the data, assumptions, and scenarios that serve as the basis for decisions about the need for generation and transmission infrastructure in the state.

California Agencies' PATHWAYS Model

The California PATHWAYS modeling project performed for California agencies by E3 in 2014-2015 looked at longer-range GHG reductions and the feasibility and cost of a range of GHG reduction trajectories to reach the 2050 target.[27] These scenarios helped inform a GHG reduction target for 2030 that was codified in Executive Order B-30-15 and later in SB 350 and SB 32.

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[24] Cary Garcia, California Energy Commission. "California Energy Demand Forecast for RETI 2.0," January 29, 2016.

[25] Energy + Environmental Economics (E3). "Estimating Renewable Transmission Needs for RETI 2.0," April 19, 2016.

[26] Public Resources Code § 25301(a).

[27] https://ethree.com/public_projects/energy_principals_study.php.

In contrast to the *IEPR* bottom-up energy projections, the PATHWAYS modeling project uses a top-down model of energy and technology scenarios, including high levels of transportation and building electrification, to identify GHG reduction strategies. In addition to the overall increase in electricity demand, the PATHWAYS study found that meeting GHG reduction goals could require a greater percentage of carbon-free energy sources in the overall electricity mix.

Based on a review of the *2015 IEPR* Low Demand, High AAEE projections, the RETI process found that the lowest level of incremental annual renewable energy needed to meet the 50 percent RPS by 2030 is around 25 terawatt-hours (TWh). Using the Mid Demand, Mid-AAEE[28] scenario, RETI 2.0 staff estimated that the mid-case incremental annual renewable energy needed to achieve 50 percent RPS in 2030 is around 40 TWh. Using PATHWAYS, the incremental renewable need is estimated to be between 51 to 76 TWh to meet a 50 percent RPS.[29] Table 1-1 shows the ranges of renewable energy needed (in terms of TWh, where 1,000,000 MWh equals 1 TWh).

Table 1-1. California Demand Forecasts and Incremental Renewable Energy Needed

		2015 IEPR (1) Low Demand High AAEE	**2015 IEPR (1)** Mid Demand Mid AAEE	**2015 IEPR (1)** High Demand Low AAEE	**PATHWAYS (2)** Straight-Line High BTM PV	**PATHWAYS (2)** Early Deployment Mid BTM PV
Electricity Demand (TWh)						
2020 Retail Sales		237	247	257	---	---
2030 Retail Sales		206	243	276	268	317
Renewable Energy Needed (TWh)						
33% RPS 2020		78	82	85	83	83
50% RPS 2030		103	122	138	134	159
50% RPS by 2030, Incremental to 2020	**Renewable Energy Needed (TWh)**	**25**	**40**	**53**	**51**	**76**
	New Capacity Needed (MW) 30% Cap. Factor	**9,400**	**15,200**	**20,300**	**19,600**	**29,000**

Sources:
1 - RETI Plenary Group Report, Planning Goals Summary (5/2/2016).
2 - E3 Estimating Renewable Energy Needs for RETI 2.0, (4/19/2016).

The California Agencies' PATHWAYS Project identified several key drivers affecting both energy demand and GHG reduction. The most significant drivers were:

- Energy efficiency and conservation savings that reduce total demand for energy.
- Growth in behind-the-meter photovoltaics and distributed generation that reduces (and shifts the timing of) the peak demand that must be met by the utility.
- Transportation electrification; the electrification of other sectors, including building and industrial energy end uses; and potential for widespread growth in other uses of electricity for desalination or hydrogen fuel production.

[28] *AAEE*, or *additional achievable energy efficiency*, is a measure of energy efficiency potential.

[29] Energy + Environmental Economics (E3). "Estimating Renewable Transmission Needs for RETI 2.0," April 19, 2016.

These key drivers can significantly affect the total demand for utility-scale renewable energy and the bulk transmission and other grid infrastructure to support it. California energy planners, utilities, consumers, and stakeholders are engaged in intensive efforts to design, implement, plan for, and quantify the effects these policies and drivers.

Since the publication of the public review draft, several commenters have suggested that state planning should focus exclusively on high-energy-efficiency and high-distributed-generation scenarios to minimize the need for new utility-scale renewable development or new transmission. This policy decision is outside the scope of RETI 2.0; however the resource goal review in RETI 2.0 has included both the lower end of the IEPR forecast, as well as a higher end, to "bookend" the evaluation of resources, TAFAs, and transmission needs in this report.

Both the Energy Commission's California Energy Demand Forecast and the PATHWAYS model have been updated over the course of 2016. The RETI 2.0 agency staff has endeavored to coordinate with these updates and ensure that the RETI planning goals remain relevant.

California Energy Commission 2016 IEPR Update

The *IEPRs* and *IEPR Updates* provide an electricity demand forecast that is used across CPUC and California ISO proceedings. The full electricity and natural gas demand forecast is done biennially and provided in the *IEPR* of odd-numbered years. On January 25, 2017, the Energy Commission adopted the *California Energy Demand Updated Forecast 2017-2027.*[30] The "Low Demand, High AAEE" case models the effect that additional energy efficiency and distributed generation (such as behind-the-meter solar PV) could have in minimizing the need for utility-scale renewable energy. These results, extrapolated by Energy Commission staff to 2030, suggest the impact of "additional achievable energy efficiency" could reach 32,798 GWh and behind-the-meter distributed generation could reach 46,442 GWh. Together these effects could reduce total retail sales to just over 209 TWh, slightly higher than the projection reported in Table 1-1 above.

ARB 2030 Target Scoping Plan Update

In response to Executive Order B-30-15 and SB 32, ARB is updating the state's regulatory GHG reduction targets to meet the 40 percent reduction goal from 1990 levels and the regulatory strategies to achieve them, including setting a GHG reduction planning goal for electric utilities to use in integrated resource planning.

On January 20, 2017, the ARB published the *2017 Scoping Plan Update: The Proposed Strategy for Achieving California's 2030 Greenhouse Gas Target*.[31] In this proposed Scoping Plan Update, ARB released sector-specific projections of energy and emissions based on an updated PATHWAYS model for California. The draft projections of the "Scoping Plan case" scenario includes a 50 percent RPS by 2030 and 31.5 TWh of generation from 18.2 GW of behind-the-meter solar PV (up from 6.4 TWh in 2015) and total retail sales of 266.5 TWh, roughly equal to the "PATHWAYS Straight-Line" case shown in Table 1-1. This scenario also includes GHG reductions from the GHG Cap-and-Trade Program, some of which could come from the electricity sector. In the "Alternative 1" case, ARB presented a scenario without cap-and-trade reductions but with enhanced electricity sector measures, including a 60 percent RPS by 2030 and 28.4 GW of behind-the-meter PV. In both the Scoping Plan and Alternative cases, the RPS was assumed

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[30] Energy Commission Resolution No. 17-0125-6, in Docket No. 16-IEPR-05 (1/25/2017).

[31] ARB. *The 2017 Climate Change Scoping Plan Update: The Proposed Strategy for Achieving California's 2030 Greenhouse Gas Target* (1/20/2017).

to increase to 80 percent by 2050. These scenarios and modeling results are preliminary. The Proposed Scoping Plan has not been adopted by the ARB.

CPUC Studies of Renewable Demand for 2030

In June 2016, CPUC staff produced RPS portfolios for use by California ISO in a special study of potential future renewable energy development scenarios for 2030. The default scenario included “commercial projects (that is, already contracted through 2026) and modeled “generic” capacity to meet a 50 percent RPS in 2030, for the CPUC-jurisdictional IOUs.[32] The incremental modeled capacity additions ranged from a high of 10,500 MW (when projects were limited to in-state FCDS) to a low of 6,751 MW when out-of-state wind and EO delivery service is included.

On December 27, 2016, the CPUC issued “Draft IRP Assumptions” for use in IRP modeling during 2017.[33] These draft assumptions include retail sales projections, based on the Energy Commission’s California Energy Demand, for the ISO-jurisdictional load. These draft assumptions project total RPS-eligible retail sales in 2030 at 195.8 TWh, yielding a 50 percent RPS obligation for ISO-jurisdictional load (that is, not including the RPS obligation of LADWP, SMUD, and other POUs) of 97.9 TWh. These draft assumptions are provisional and have not yet been adopted in the CPUC IRP proceeding.

Renewable Energy Demand Timeline to 2030

The demand projections and RPS obligations explored in the studies cited above focus on the aggregate demand for renewable energy in the 2030 target year. In addition to this long-term demand, there are important midterm milestones and targets and separate factors that will influence how these goals are achieved. Among these are the midterm RPS targets, the utilities’ existing renewable energy contract positions, and the influence of federal tax credits.

The Clean Energy and Pollution Reduction Act of 2015 (SB 350) set interim RPS targets of 33 percent by December 31, 2020, 40 percent by December 2024, 45 percent by December 2027, in addition to the goal of 50 percent by December 31, 2030. According to the CPUC, the three major IOUs have in recent years taken advantage of declining power purchase agreement costs to proactively contract for sufficient renewable resources to meet their current obligations in 2020 and beyond. Table 1-2 below illustrates the current procurement status of the three large utilities, as of August 2016. While these data do not account for potential contract expiration that may occur after 2020, they do suggest that adequate renewable resources may already be developed to satisfy the large IOUs’ requirements through at least the mid-2020s time frame.

Table 1-2. California’s Major IOUs, Progress in RPS Procurement

	Actual RPS Procurement Percentages in 2015	Percentage of RPS Procurement Currently Under Contract for 2020
PG&E	29.5 %	43.0%
SCE	24.3%	41.4%
SDG&E	35.2%	45.2%

Source: CPUC Current Renewable Procurement Status (updated August 2016).

[32] CPUC staff. RPS Calculator Portfolios for CAISO 2016 Special Study (6/20/2016).

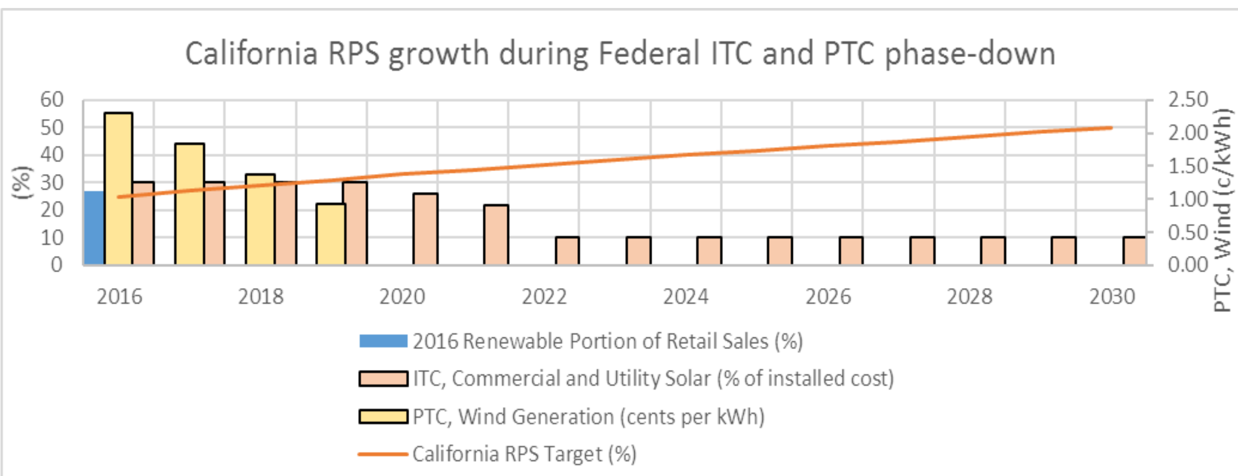
[33] CPUC staff. Draft IRP Assumptions Values (spreadsheet) and Sources (12/27/2016).

At the same time, other factors may suggest a continuing incentive for renewable energy resource development sooner rather than later. One important consideration is the SB 350 mandate for the electricity-sector to meet GHG reductions that may require a greater quantity of renewable energy than required for RPS compliance. Other drivers of renewable procurement in the near term include the continuing decreases in capital costs for renewable energy technologies, increases in fossil power costs or retirement of fossil capacity, and the financial incentive of federal tax credits.

Federal tax policies provide substantial subsidies for developing renewable energy. The federal Investment Tax Credit (ITC) and Production Tax Credit (PTC) help make investing in renewable energy more attractive. Across the West, in conjunction with RPS policies, these credits have been potent drivers of investment. The ITC is currently a 30 percent federal tax credit claimed against the tax liability of investors in commercial and utility-scale solar energy property that will step down to 10 percent by 2022. The PTC is currently worth 2.3 cents for every kilowatt-hour of wind energy generated, although this will step down so that wind projects that begin construction after 2019 will not be eligible to receive the credit. Given the long lead times for renewable development and transmission expansion, future infrastructure investments appear likely to face a market driven mostly by RPS policies.

Figure 1-1 shows the growth in the California RPS to 50 percent by 2030, with the SB 350 interim milestone targets of 40 percent by 2024 and 45 percent by 2027, alongside the phase-down of today's federal tax credits. This chart suggests that investment in wind and solar projects prior to the phase-out of credits in 2019 may be an attractive component of meeting long-term renewable energy targets.

Figure 1-1. RPS Targets and Federal Tax Credits



Source: Aspen Environmental Group; U.S. Energy Information Administration (EIA) discussion of December 2015 enactment of the Consolidated Appropriations Act, 2016.

Utility-Specific Expectations on Quantities of Renewables

California's statewide portfolio of renewable energy resources is effectively a mix of the energy resources procured by the numerous load-serving entities. In addition to planning agencies' expectations for the quantity, the RETI 2.0 process gathered the following highlights from utilities during a Plenary Group meeting on March 16, 2016:

- Pacific Gas and Electric Company (PG&E) and SCE emphasize the importance of having planning tools that achieve a diverse portfolio mix of resources[34] and "products" that in total meet the system and local needs,[35] with this being challenged by location-specific attributes of resources, potential curtailments, and the shift in peak load to later hours in the day.
- San Diego Gas & Electric Company (SDG&E) plans to procure 2 to 3 TWh more renewable energy in 2030 than in 2020, with out-of-state wind appearing attractive due to a high capacity factor and an output profile that is not correlated with solar.[36]
- LADWP plans to procure 5 TWh more renewable energy in 2030 than in 2020, with growth dominated by solar resources and heavily supported by additional wind and geothermal; electrification of the transportation sector plays a significant role in reducing LADWP area GHG emissions.[37]
- Sacramento Municipal Utility District (SMUD) anticipates need for 1 to 2 TWh of incremental renewable energy in 2030, based on an RPS surplus and renewable energy credits.[38]
- Imperial Irrigation District (IID) emphasizes the need for procurement to factor appropriately the ramping, dispatch, and ancillary service capabilities of geothermal, the locational attributes of each resource, and the possible benefits to disadvantaged communities that may be realized through resource procurement decisions.[39]

Renewable Energy Resources Availability and Capability

While the original RETI project in 2009 entailed extensive and detailed documentation of resource costs in different areas around the state, RETI 2.0 involved only a brief review of renewable resource costs. The intent was to identify the evolution in costs since the last RETI process and to identify where recent improvements in technologies, planning, and permitting have improved the relative attractiveness of renewable resources in different areas.

RETI 2.0 also reviewed the development in understanding the portfolio cost of different renewable resources — that is, the contribution of resources to the total cost of a given LSE's portfolio of different renewable resources, including the capabilities of different technologies toward providing capacity, flexibility, ancillary services, and other qualities necessary to meeting all the needs of the utility and the grid at different times. This latter topic is also responsive to the new mandates within the SB 350 statute to ensure that LSEs and the CPUC are planning for "diverse and balanced portfolio for … optimal integration of renewable energy."

[34] PG&E. RETI 2.0 Plenary Group Workshop: Resource Values (3/16/2016).

[35] SCE. Presentation for IOU Panel (3/16/2016).

[36] SDG&E. Renewable Resources to Meet 2030 Goals (3/16/2016).

[37] LADWP. LA's Power Transformation Overview (3/16/2016).

[38] SMUD. SMUD: 50% RPS by 2030 (3/16/2016).

[39] IID. RETI 2.0 Plenary Group Workshop Presentation (3/16/2016).

Renewable Resources in California

Renewable energy resource potential across California has been widely studied and well documented. A major product of the original RETI effort was a detailed, GIS-based database of renewable resource potential and cost that was institutionalized in the CPUC's RPS Calculator.[40]

During the RETI 2.0 outreach, stakeholders offered insight into what renewable development companies, utilities, and regulators considered the most cost-effective resources. All participants agreed that "low-cost solar photovoltaic potential is ubiquitous in California." While some areas obviously receive more solar insolation than others, broad regions within the state contain substantial potential for cost-competitive solar energy production. The latest calculator (Version 6.2) provides an indication of California's abundant solar resources. The developable potential for solar PV within California is "very high," roughly 109,000 MW.[41]

Moreover, several areas within the state with high solar resource potential have been the subject of more or less comprehensive land-use planning to facilitate renewable energy development. The most comprehensive of these is the Desert Renewable Energy and Conservation Plan (DRECP) that resulted in a Land Use Plan Amendment (LUPA) to promote and streamline permitting on Development Focus Areas (DFAs) on BLM lands within the area. Several counties within the DRECP area also completed land-use planning for renewable energy resources that establishes preference areas. Finally, the San Joaquin Valley Solar Report[42] represented an informal, non-regulatory effort to identify priority lands for development.

Wind resources in California are more geographically limited. California contains several areas with very high-quality wind, and several of these areas have seen substantial development – including Altamont, San Gorgonio, and Tehachapi Pass areas. Several areas around the state –including Northern California areas in the Sacramento Valley and Lassen and Modoc Counties—contain significant technical medium-quality wind resources. Importantly, new turbine technologies may be making even medium-quality wind cost-competitive. In addition, offshore wind is another nascent resource that has not been studied extensively, though the state and federal governments recently announced a joint effort to do so.[43]

While the RPS Calculator has identified substantial wind potential in California, the California Wind Energy Association (CalWEA) has noted that the best remaining wind resource areas have been constrained due to county moratoriums on wind, unattainable sound standards, or wind prohibitions on some high-quality wind resource areas.[44] CalWEA has also expressed concern about the need to repower older wind projects where the contracts are at risk of expiring and has identified several barriers to repowering, including competition from solar PV, tax policy disadvantages, and a lag on the bid evaluation components that would likely favor wind such as integration costs, capacity value, and

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[40] The CPUC's RPS Calculator provides one of the more comprehensive databases of renewable resource locations, costs, and capabilities. The calculator documentation is available at http://www.cpuc.ca.gov/RPS_Calculator/ and can be explored geographically at http://databasin.org/maps/6301220932e94d598b2278c0c4e11737.

[41] CPUC Energy Division, *RPS Calculator User Guide* (v. 6.2), Appendix B, p.B-14b (3/15/2016).

[42] Pearce, Dustin, James Strittholt, Terry Watt, Ethan N. Elkind. *A Path Forward Identifying Least-Conflict Solar PV Development in California's San Joaquin Valley*; Center for Law, Energy & the Environment (CLEE), May 2016; https://www.law.berkeley.edu/wp-content/uploads/2016/05/A-PATH-FORWARD-May-2016.pdf.

[43] "BOEM Initiates Planning for California Offshore Renewable Energy Task Force," Bureau of Ocean Energy Management, May 31, 2016, https://www.boem.gov/press05312016/.

[44] For a complete list of CalWEA's concerns regarding new wind projects and repowering barriers, see "The (Limited) Wind Energy Potential in California" presentation by Nancy Rader (March 16, 2016 workshop).

recognition of curtailment costs. In sum, CalWEA has estimated the maximum new wind potential as 1,000 MW in the desert region and 2,000 MW in all of California.

Geothermal resources are even more geographically defined, though several areas within California are home to world-class geothermal resources. The cost of developing new geothermal facilities was identified as a very important but uncertain variable. While basic geothermal technologies are considered mature and costs are very site-specific, developers cited cost reductions in exploration and development, higher capacity factors, and previously unquantified flexibility and ancillary service capabilities as offering the potential to assist in the integration of greater levels of renewable energy resources.[45] Proponents also cited several challenges to geothermal energy development, such as inadequate value attributed to geothermal capacity and ancillary services, inequity in state and federal tax policy, and difficulties recovering high initial capital costs within the time frames of a typical PPA.[46]

Biomass resources available for electricity production were identified in several important areas of the state, notably along the worst-hit areas for tree mortality in the central and northern Sierra Nevada. However, in discussions with biomass industry and local representatives, none of the potential facilities contemplated were above 20 MW and, therefore, would not require significant new high-voltage transmission.[47]

Renewable Resources Around the West

The natural availability of renewable energy across the West is widespread, especially for wind and solar. There is wide geographic diversity in the availability of renewable energy. Oregon and Washington are major resources for hydroelectric (hydro), wind, and biomass. High-value solar is readily available in Arizona and Nevada, and wind potential is vast in eastern Wyoming and New Mexico. Geothermal is available throughout central and northern Nevada and southern Oregon.

An additional 10,000 MW of solar and 7,000 MW of wind generating capacity is forecasted by WECC to be added by 2024.[48] California's 50 percent RPS and RPS requirements in nine other western states will incentivize further additions by 2030 and beyond. As each state moves closer to compliance with individual RPS policies, other renewable energy, beyond that needed for RPS compliance, may also become economical across the West. About 1.4 percent of the WECC-wide load in 2024 is forecasted to be served by renewable energy facilities that are beyond those needed for RPS compliance.[49]

Outside California, solar energy in Arizona can be generated at a capacity factor that is equal to the best of California's solar resources. The abundant natural availability of wind in Wyoming, New Mexico, and, to a slightly lesser extent, Idaho and Oregon translates into relatively low costs for the renewable energy generated in those regions. Because wind in these areas is less intermittent than in other areas, wind

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[45] "Ormat Nevada Inc." Rahm Orenstein, Presentation to RETI 2.0 Plenary Group workshop, March 15, 2016, http://docketpublic.energy.ca.gov/PublicDocuments/15-RETI-02/TN210772_20160317T143457_Ormat_Presentation__Orenstein.pdf

[46] "Salton Sea Geothermal: Capabilities, Benefits, and Limitations," Derek Benson, EnergySource, Presentation to RETI 2.0 Plenary Group workshop, March 15, 2016, http://docketpublic.energy.ca.gov/PublicDocuments/15-RETI-02/TN210743_20160315T152443_Salton_Sea_Geothermal_Capabilities_Benefits_and_Limitations__Be.pdf.

[47] "Re: Proposed bioenergy facilities and status," Jim Branham, Sierra Nevada Conservancy, RETI 2.0 comment letter, July 21, 2016. http://docketpublic.energy.ca.gov/PublicDocuments/15-RETI-02/TN212442_20160725T111457_Sierra_Nevada_Conservancy_letter_72116.pdf.

[48] WECC 2024 Common Case. WIEB, RETI 2.0 Planning Goals Workshop Slides (1/29/2016).

[49] WECC 2024 Common Case. WIEB, RETI 2.0 Planning Goals Workshop Slides (1/29/2016).

turbines in these areas will have a high capacity factor (more than 40 percent), and this directly translates to relatively low costs for the wind energy. South Oregon and Idaho, and northern Nevada especially, have also developed high-quality geothermal energy resources and may have potential for other cost-effective geothermal development.

In addition, geographically constrained, large-scale storage facilities – including pumped hydro and compressed air energy storage – may be developed at favorable sites around the West.[50]

The overall renewable energy potential across the West is limited by the ability to deliver the energy through the existing transmission system and by the costs of bringing new interregional transmission projects into reality. The availability of rights on existing transmission changes over time as retirements free up capacity. The scope of retirements is not always well known in advance. By 2024, WECC expects 7,200 MW of coal-fired power plant retirements,[51] but this is almost certain to grow as 2030 approaches. In the SB 350 study of a regional ISO market, the Brattle Group used modeling that assumed 14,000 MW of coal-fired capacity retirements based on a review of the WECC 2026 Common Case and recent plans from utilities.[52]

Diverse and Balanced Portfolios and Optimal Integration of Renewable Energy

Public Utilities Code Sections 399.11, 701.1 and, for CPUC-jurisdictional LSEs, Section 454.51 and 454.52 require planning for a “diverse and balanced portfolio” while balancing the goals of reliability and cost-effectiveness. Beginning in 2017, California’s investor-owned utilities’ IRPs are required by SB 350 to show compliance with GHG targets and a “diverse and balanced portfolio of resources … that provides optimal integration of renewable energy.”

With SB 350, California’s IRPs will need to establish valuations for the GHG-reducing capabilities of renewable energy resources and for the GHG-related effects of other resources within the utility’s reach, including energy efficiency, demand response, energy storage, or fuel-switching opportunities. SB 350 triggers the need to develop a framework for valuing the GHG attributes of procurement decisions, in addition to the more traditional reliability-driven and cost-based valuation framework.[53]

Conventionally, cost-based valuation begins with the levelized costs of energy (LCOEs), which serve as a proxy for power purchase prices in utility contracts. For renewables, LCOEs vary depending on the technology, the technological maturation, and changes to tax incentives and financing environment.[54] LCOEs can vary even for the same technology according to site-specific conditions.[55]

Cost-based valuation includes consideration of transmission and integration costs, as well as the system-driven potential for curtailment. The components of net cost and the ultimate effect of a renewable energy resource on California ratepayers are incorporated and used widely in California’s

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[50] One such potential facility is the Pathfinder Compressed Air Energy Storage proposal for a 320 MW (expandable to 1,200 MW) CAES project using geographically rare salt caverns – located adjacent to the existing Intermountain Power Plant in Utah and the associated HVDC transmission line to LADWP. http://www.pathfinderwindenergy.com/caes/

[51] WECC 2024 Common Case. WIEB, RETI 2.0 Planning Goals Workshop Slides (1/29/2016).

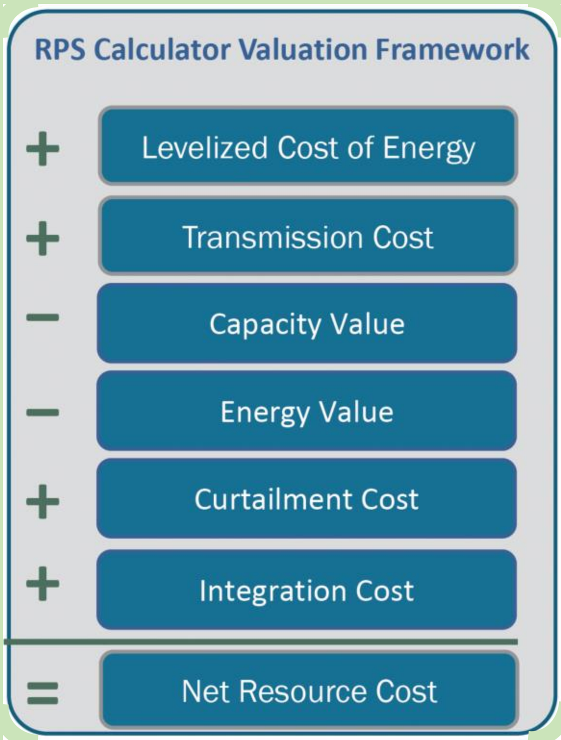
[52] *California ISO SB 350 Study*. Production Cost Simulation. Volume V, p. V-17 (7/8/2016).

[53] CPUC Staff Concept Paper on Integrated Resource Planning (8/11/2016).

[54] E3. Identifying High-Value Renewable Resources (3/16/2016).

[55] “Cost of Generation Model: Cost Competition and Technology Trends,” Bryan Neff, California Energy Commission, Presentation to RETI 2.0 Plenary Group Meeting, March 16, 2016.

Valuation Components in CPUC Procurement Framework



Source: E3. Identifying High-Value Renewable Resources (3/16/2016).

procurement and planning frameworks, including least-cost best-fit assessment, and in the RPS Calculator (Version 6.2).

Power procurement actions by utilities must also consider portfolio effects and may adjust the valuation of a given resource for the associated location, energy and load-shaping capabilities, potential for curtailment, or other specific portfolio-driven objectives.[56] The text box illustrates the valuation components considered in the CPUC's procurement proceedings and in individual utilities' decision-making. However, the specific values to use in each of these calculations are complex, contentious, and evolving over time. Energy values, capacity values, integration costs, and least–cost, best-fit reform are all the subject of ongoing proceedings at the CPUC.[57]

California's experience with high penetrations of renewable energy resources is already demonstrating an increased need for diversity in the resource mix. Declining capacity and energy values and increasing curtailment and integration costs are diminishing the returns with the expanding scale of renewables in the mix and will tend to encourage resource diversity.[58]

The benefits of portfolio diversity include an ability to partially address many of the challenges anticipated at higher penetrations of renewable energy resources. For example, the renewable integration challenge of oversupply is directly linked to the concentrated production from solar resources during daytime hours, and geographic and technological diversity can distribute renewable production more evenly throughout the year.[59]

Operational Diversity

Several commenters to the public review draft suggested aspects of grid operations and non-generation energy resources as a form of operational diversity complementary to a "diverse and balanced portfolio." These complementary aspects include the diversity of deliverability status (EO vs FCDS); firm

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[56] PG&E, Presentation to RETI 2.0 Plenary Group Meeting (3/16/2016).

[57] Revisions to these values and methodology are being considered under the Renewables Portfolio Standard and the Integrated Resource Proceeding at the CPUC. Commenters to the PRD suggested further emphasis on the reform of least-cost best-fit methodology and how this may affect selection of renewable energy technologies in the future, including the recognition of value to flexibility and ramping energy and other renewable energy integration services, as well as the recognition of avoided transmission costs for distributed energy resources.

[58] E3. Identifying High-Value Renewable Resources, Presentation to RETI 2.0 Plenary Group (3/16/2016).

[59] CPUC staff. Proposed Approach to Scenario Development for Integrated Resource Planning. (10/24/2016).

and conditional transmission service; diversity of power markets and products; geographic diversity of transmission load; and advanced grid technologies.

Diversity in deliverability status (FCDS and EO) can make greater use of existing transmission (and reduce costs for new transmission) while ensuring resource adequacy. Diversity in transmission service (firm and conditional firm) in bilateral markets may similarly maximize transmission utilization while managing curtailment risk. The EIM represents an important new ingredient to diversity of power markets that could be expanded, along with other short-duration power products. Commenters suggested that geographic diversity of transmission service can reduce costs because of reduced regional load, such as balancing the development of renewable resources in Southern California against those in the north. And lastly, some commenters noted that advanced technologies like HVDC, power flow control, and grid-scale storage can be important tools to improve the balance of renewable resources.

Metrics for Portfolio Balance

One key metric in the consideration of an optimal portfolio is minimizing the potential for oversupply. Oversupply occurs when all anticipated generation, including renewables, exceeds real-time demand. During oversupply times, wholesale prices can be very low or even negative, creating a situation in which generators have to pay utilities to take the energy. Prices and market forces typically remedy the oversupply situation and restore supply and demand balance. Thus, oversupply is typically manageable

If oversupply is not entirely corrected by the automatic systems of the market, it can lead to a reliability condition called *overgeneration*. At this point, grid operators must manually step in and correct the condition. This condition rarely occurs, but unless steps are taken now to proactively manage the grid to avoid oversupply and overgeneration, the number of hours in which overgeneration could occur is predicted to increase over the next decade. [60]

Another metric driving the search for optimal portfolios is ramping capacity needs. Meeting large increases and decreases to electrical demand has long been a concern for grid operators, but increasing renewable energy penetration is changing the magnitude, speed, and duration of the ramping energy capacity needs.

Oversupply and ramping concerns can be illustrated by using the net load curves, as shown in the well-known “duck chart.” The duck chart illustrates these differences between forecasted load and expected electricity production from variable generation resources. For certain times of the year, these curves produce a “belly” appearance in the midafternoon that quickly ramps up to produce an “arch” similar to the neck of a duck. From the California ISO perspective,[61] the development of the overall resource portfolio must consider these operational challenges:

- Short, steep ramps – when the ISO must bring on or shut down generation resources to meet an increasing or decreasing electricity demand quickly, over a short period.
- Oversupply risk – when more electricity is supplied than is needed to satisfy real-time needs.
- Decreased frequency response – when fewer resources are operating and available to adjust electricity production automatically to maintain grid reliability.

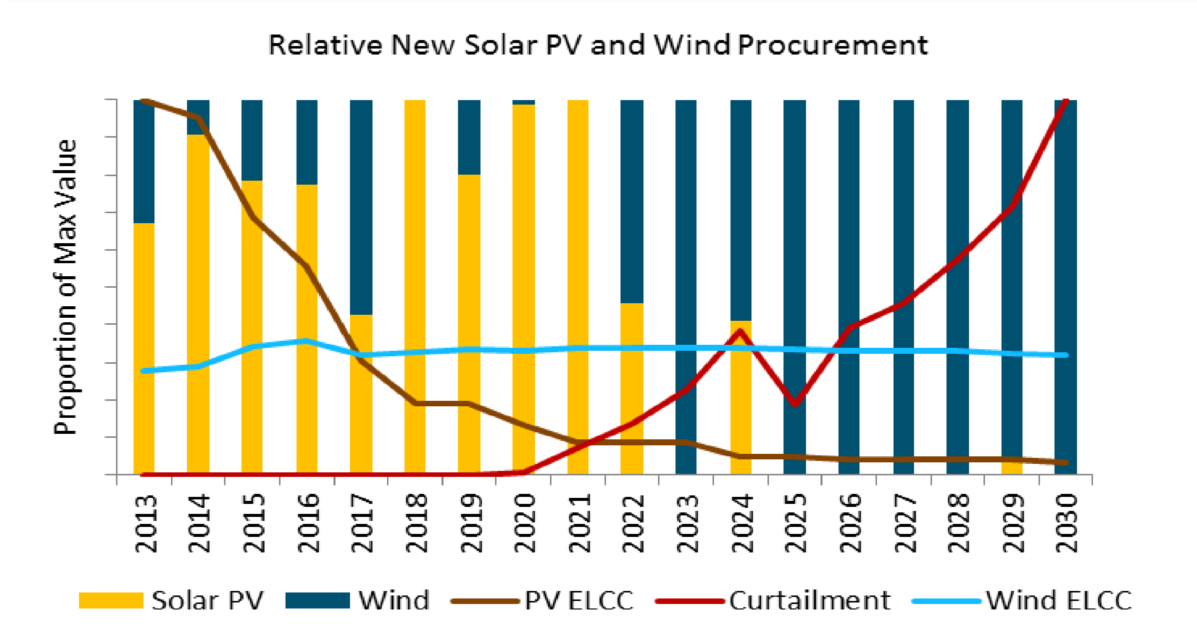
The following chart illustrates the effect two other important metrics — capacity value and curtailment costs — can have on overall portfolio. Figure 1-1 illustrates one example of how capacity value (here

[60] E3, Investigating a Higher Renewables Portfolio Standard in California (2014),

[61] https://www.caiso.com/Documents/FlexibleResourcesHelpRenewables_FastFacts.pdf

expressed as "effective load-carrying capacity" or ELCC) can change over time as the proportion of solar or wind resources increases. It also shows the change in total curtailment costs as solar resources increase. Finally, it illustrates how the increasing costs and decreasing value of solar, and relatively constant capacity value of wind, lead to a dramatic switch in procurement in the 2022-2025 time frame. It is important to emphasize that this image represents just one modeled scenario that is affected by many assumptions — but the dynamic represents high penetrations of correlated generation and supports the priority for balanced and optimal portfolios.

Figure 1-2. CPUC Example of Load Carrying Capacity and Other Value Trends



Source: Presentation by Forest Kaser (CPUC) to RETI 2.0 workshop, April 18, 2016.

Low Carbon Grid Study

The Low Carbon Grid Study (LCGS) is a long-range study and modeling platform for analyzing California and west-wide electricity and GHG emission futures. Modeling is being conducted primarily by the National Renewable Energy Laboratory (NREL) with stakeholder coordination and policy support by the Center for Energy Efficiency and Renewable Technologies.[62] The LCGS provides valuable insights into strategies, including diverse portfolios, to support optimal integration of renewables.

The LCGS confirms findings from the PATHWAYS model that electric sector and economy-wide GHG reduction strategies are closely linked. In the 2030 to 2050 time frame, the trajectory of GHG emissions from the electric power sector is greatly influenced by the pace of load growth, due to electrification of both the transportation and building-energy use sectors, which in turn is influenced by the need to reduce GHG emissions from transportation, industry, and commercial and residential sectors.[63]

[62] http://lowcarbongrid2030.org/.

[63] CEERT. Low Carbon Grid Study Phase II Results (2016). http://lowcarbongrid2030.org/wp-content/uploads/2016/PDFs/160307_PhaseIIResults.pdf.

Key findings for reducing emissions from the electric power sector by 2030 emphasize the benefits of "enhanced flexibility," which includes:[64]

- A technologically and geographically diverse renewable energy portfolio, including grid-scale PV solar, rooftop solar, regional wind, geothermal, biomass, and concentrating solar power with thermal storage.
- Real-time carbon accounting for dispatch and unit commitment, as well as procurement and planning.
- Bulk storage benefits shared across multiple balancing authorities[65] and utilities, including both new projects and an optimized, statewide use of existing non-IOU pumped hydro.
- Essential reliability services provided by non-thermal resources, including the hydroelectric fleet.
- Strategic dispatch of natural gas resources, staggered quick starts to prevent idling and ramping.

Low Carbon Grid Study
Individual Resource Studies

Using the Low Carbon Grid Study modeling platform, advocates have commissioned follow-on studies from NREL and the Center for Energy Efficiency and Renewable Technologies (CEERT) to quantify the benefits of individual resources under different scenarios of resources, load, and transmission. Three studies submitted to RETI 2.0 address the difficult assessment of individual resource benefits in a 2030 portfolio:

- Great Basin Transmission, LLC commissioned a study of the benefits of SWIP North transmission, finding significant economic, reliability, and environmental benefits from the resource and load diversity and regional grid enhancement the project delivers.
- The American Wind Energy Association funded an analysis to quantify the value of high-capacity-factor wind within the West as a part of the California renewable energy portfolio. The study found that regional wind could significantly lower system-wide costs and increase the operational value of domestic renewable technologies, enabling a net higher quantity of California-based solar and other renewable energy projects.
- The Walton Family Fund sponsored a study of the benefits of adding 1,250 MW of geothermal capacity in the Salton Sea area to a 2030 resource portfolio, in place of 3,800 MW of solar capacity (both producing 10 TWh of energy), and found benefits to production and curtailment costs, capacity and flexibility, and GHG emissions.

The Low Carbon Grid Study analysis for a 50 percent emission reduction in California uses additional transmission as a way to best access the mix of out-of-state resources. The target scenario includes transmission to connect the Wyoming wind to the terminus of the Intermountain Power Project DC line in Delta, Utah; to connect southern Idaho to southern Nevada, which improves power-transfer capability between the northern and southern portions of the Western Interconnection and reduces flows on the path from PG&E into SCE (Path 26); and to increase deliverability of renewable energy from IID into the remainder of California.[66]

See the text box for LCGS insights about specific resource types.[67,68,69]

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[64] California 2030 Low Carbon Grid Study; Presentation by Greg Brinkman, RETI 2.0 Workshop; April 18, 2016.

[65] *Balancing authorities* are the entities legally responsible for maintaining electricity supply-demand balance within its balancing authority area. (See https://www.eia.gov/tools/glossary/index.cfm?id=B).

[66] Brinkman, Greg, et al. (NREL). 2016. *Low Carbon Grid Study: Analysis of a 50% Emission Reduction in California*. Technical Report: NREL/TP-6A20-64884. January. (http://www.nrel.gov/docs/fy16osti/64884.pdf)

[67] Caldwell, James H. and Dr. Liz Anthony. T*he Value of Regional Wind Energy in California's Carbon Constrained Future;* Center for Energy Efficiency and Renewable Technology, May 2016.

Other Portfolio Studies

In addition to the LCGS, several recent studies have proven influential in setting the terms of debate around balanced portfolio issues and focus areas for policy reform. These include:

Beyond 33% Renewables: Grid Integration Policy for a Low Carbon Future, CPUC Staff White Paper, (2015).[70] This study presents a series of potential approaches for policies or programs to provide additional flexibility. Examples include modifying rate structure, net energy metering, and vehicle charging tariffs to align with grid needs; considering new procurement targets for storage and flexible capacity; and adopting revisions to an "integration adder" to better account for the grid integration costs of renewables procurement.

Investigating a Higher Renewables Portfolio Standard in California, Energy + Environmental Economics (E3), (2014).[71] This study was sponsored by California's major utilities to find the operational challenges of the 50 percent RPS and potential solutions and costs of integrating the variable renewable resources. This study finds extensive oversupply primarily due to solar generation during midday hours; the study treats renewable curtailment as a default solution to maintain reliable grid operations.

Western Wind and Solar Integration Study, National Renewable Energy Laboratory, (2013).[72] This study examined the impact of up to 33 percent wind and solar energy penetration on the U.S. portion of the Western Interconnection. The study quantifies wear-and-tear costs resulting from fossil-fuel power plant cycling, including start-up costs and ramping costs, while considering the impacts of the variability and the uncertainty of wind and solar on starts, ramps, and overall operation of the western power system.

Summary of Resource Conclusions

Renewable energy demand:

- There is a wide range in forecasts of potential future need for utility-scale renewable generation by California utilities to meet 2030 goals.
- High energy-efficiency, high distributed-energy-resource scenarios may reduce the need for utility-scale renewable energy, which may reduce the need for additional bulk transmission.
- Large LSEs may already have sufficient renewable energy under contract to meet RPS obligations through the mid-2020s or beyond. However, the SB 350 mandate to meet GHG targets, the ongoing reduction in renewable energy capital costs, the (near-term) availability of federal tax credits, and the growth of CCA and corporate buyers will also impact the scale and timing of non-RPS demand.

Renewable energy potential: The Plenary Group reviewed renewable resource costs and values in California, focusing on long-term trends and potential from the current year to 2030. The group confirmed that:

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[68] Pfeifenberger, Johannes, Judy Change, Michael Hagerty, Pablo Ruíz, and Cady Wiltsie. *Benefits of the Southwest Intertie Project-North (SWIP North).* Prepared for Great Basin Transmission. March 31, 2016.

[69] Caldwell, James H. and Dr. Liz Anthony. The *Value of Salton Sea Geothermal Development in California's Carbon Constrained Future*; Center for Energy Efficiency and Renewable Technologies. March 2016.

[70] http://www.cpuc.ca.gov/uploadedFiles/CPUC_Website/Content/Utilities_and_Industries/Energy/Reports_and_White_Papers/Beyond33PercentRenewables_GridIntegrationPolicy_Final.pdf.

[71] https://ethree.com/documents/E3_Final_RPS_Report_2014_01_06_with_appendices.pdf.

[72] http://www.nrel.gov/grid/wwsis.html, and http://www.nrel.gov/docs/fy13osti/55588.pdf.

- Low-cost, utility-scale solar photovoltaic (PV) is cost-competitive across much of California.
- Many of the highest-quality wind resources in California have already been developed or are constrained by environmental and permitting barriers. However, wind turbine technology improvements allow for a greater range of wind resources to be developed cost-effectively.
- Geothermal technologies have made important strides in development cost reduction and generation flexibility, and development in the Salton Sea area offers important co-benefits.
- Substantial high-quality, out-of-state renewable energy resources are under active development.

Optimized portfolio issues: The Plenary Group also reviewed recent studies examining potential large-scale portfolios of renewable resources for California from 2026 to 2030 and found that:

- Without integration solutions, continued growth in solar PV resources will lead to increased costs from a surplus of generation during periods of high solar generation, and a shortage of system and flexible capacity at other times.
- Technology and geographic diversity of renewable resources can reduce these costs by decreasing curtailment and increasing system capacity and (potentially) flexible capacity.
- Access to low-cost renewable resources both within California and out of state, especially wind and geothermal resources with generation profiles complementary to California solar generation, as well as access to energy markets outside California, can increase the diversity of renewable resources, provide markets for excess generation, and reduce ratepayer costs.

Part 2. Transmission Assessment Focus Areas

This section summarizes the environmental, land-use, and transmission issues associated with each of the TAFAs, and the process for gathering and synthesizing data. Detailed information for each TAFA is presented in Appendix A.

TAFA Goals and Process

The TAFAs are a geographic grouping of renewable energy resource potential used during RETI 2.0 to explore potential transmission, environmental, and land-use implications of large-scale development. The Plenary Group identified eight TAFAs within California, as well as import-export routes and areas outside the state, where significant quantities of renewables could potentially be developed or transmitted to help meet the 2030 renewable development goals.

For each TAFA, the Plenary Group identified a hypothetical study range (HSR) of potential development for wind, solar, and, where applicable, geothermal resources. Biomass resource potential was not specifically included in the hypothetical study range, as the capacity of each biomass energy facility tends to be small and has minimal impact on high-voltage transmission development.

The Plenary Group identified this hypothetical upper-bound renewable development potential range through 2030 based on a qualitative assessment of renewable resource technical potential, commercial interest in the area, and the technical feasibility of transmission development. Furthermore, the estimates for several TAFAs are guided by existing resource area studies, including the *Desert Renewable Energy Conservation Plan (DRECP)* and *A Path Forward: Identifying Least-Conflict Solar PV Development in California's San Joaquin Valley* (San Joaquin Valley Solar Study).

These hypothetical study ranges sought to provide a conceptual context for assessment. The hypothetical resource range provides a starting point from which to ask a "what if?" question to each of the RETI 2.0 Input Groups. In other words, each RETI 2.0 Input Group was asked, "What if an additional 5,000 MW of renewable energy development were proposed in the San Joaquin Valley – what transmission, environmental, and land-use issues could arise?"

This analysis differs from a traditional procurement and transmission planning that are built around a portfolio of renewable resources. Traditional procurement and transmission planning rely on portfolios of renewable resources that typically include smaller quantities of resources from a broader area. Because the many variables that shape portfolio assumptions can lead to very different portfolios and development scenarios in individual areas, portfolios may not reveal the limitations for development in each area.

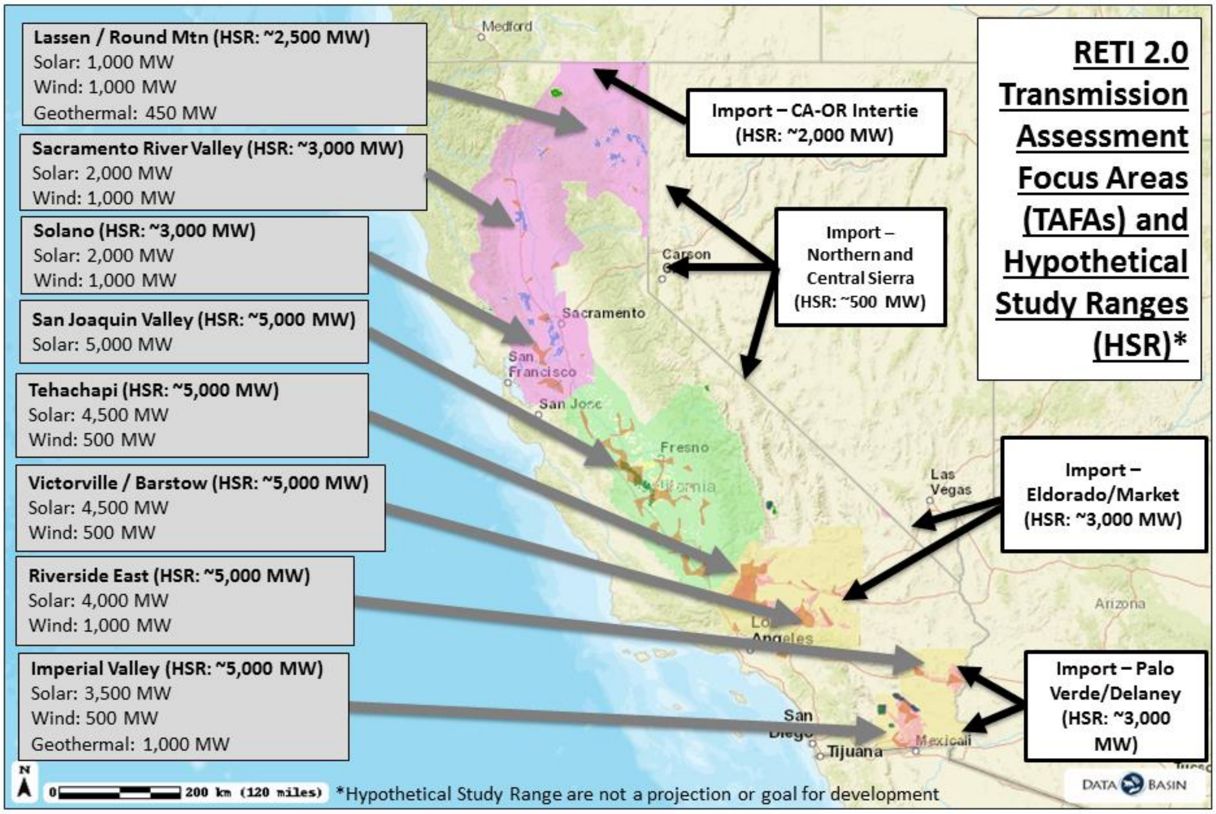
The TAFAs deliberately pose a high-end development scenario to identify long-term, large-scale constraints and opportunities and to help focus attention where significant solutions may be required, if development in any one area reaches these high levels. As summarized below, several areas could support development at these levels with existing land-use planning and transmission, whereas other areas may require additional transmission and/or land-use planning, while other areas are unlikely to reach these development levels because of a lack of both transmission capacity and limited land-use planning.

Categories of TAFAs

The Plenary Group identified three categories of TAFAs.

- **In-state TAFAs** are geographic areas that were assessed for transmission needs and environmental and land-use constraints. The in-state TAFAs do not focus on specific projects or specific sites, but rather general areas where new generation could be developed to meet California's goals.
- **Import/export paths** are the interconnections between California transmission systems and out-of-state transmission systems. These paths were evaluated for the ability to deliver new renewable energy imports from out of state and to deliver exports of surplus renewable energy from California.
- **Out-of-state TAFAs** are very broad geographic areas in western states with high renewable energy potential. The out-of-state TAFAs are assessed for deliverability to California import-export paths.

Figure 2-1. Transmission Assessment Focus Areas (TAFAs) and Hypothetical Study Ranges



Source: RETI 2.0 Staff

TAFAs are:

- General geographic areas with unique mix of renewable energy and transmission system characteristics.
- Assigned a hypothetical study range (HSR) representing a "what if" question of potential renewable energy development, to gather feedback on implications from stakeholders.
- Assessed individually, not as a scenario.
- Used to identify transmission constraints or environmental issues that may need to be addressed, if development is pursued.

TAFAs are NOT:

- A definitive geographic area or regulatory or technical boundary.
- A projection or goal for renewable energy development.
- A comprehensive accounting of renewable resource potential, transmission capability, environmental and land-use issues.
- Used in combination or as a scenario.
- Meant to identify transmission projects or environmental issues that should be addressed or that are recommended.

Data Sources Used in the Assessment of TAFAs

Once the TAFAs were established and given a hypothetical range of renewable energy development, they were provided to the TTIG,[73] the Environmental and Land Use Technical Group (ELUTG), and the Western Outreach Project. As described below, each group was tasked with a specific portion of the RETI process.

In addition to the three Input Group reports, US BLM provided input based on the ongoing West Wide Energy Corridor (Section 368) Review. Lastly, the assessment described in the plenary report and in Appendix A represents a synthesis by the RETI 2.0 staff and consultants Aspen Environmental Group of these sources along with other existing sources, including the DRECP and County planning documents.

TTIG Report

The TTIG assembled relevant in-state transmission capability and upgrade cost information to inform the assessment of each TAFA. In effect, the TTIG answered a series of “what if” questions regarding the transmission implications of interconnecting the large-scale hypothetical study range(HSR) of additional renewable resources in each TAFA.

The estimates of available and new transmission requirements and cost are based on existing information and data provided by TTIG members and other RETI stakeholders. Much of the information comes from transmission reliability and interconnection studies performed by balancing authorities, as well as utility and balancing authorities’ planning studies. TTIG did not independently develop any information or perform system modeling to develop projections of existing or new transmission capacity.

TTIG focused on the bulk electricity system and the delivery of energy resources from the interconnection with the bulk system to load centers. Neither the TTIG report nor this report includes consideration of the costs to interconnect individual generation projects with the bulk electricity system.

The existing transmission capability estimates included in the TTIG report are based in part on transmission projects that have been recently completed or are under development. As such, the TAFA transmission constraints and conceptual solution examples frequently assume some transmission upgrades that are not yet in service were in place for the purpose of evaluating the TAFA.

TTIG believes that the information provided is reliable and appropriate for the planning nature of RETI 2.0 but cautions that the information is highly conceptual and should not be relied on for assessing specific resource interconnections. The costs included in the TTIG report should be considered as “order of magnitude” costs; they do not reflect any engineering estimates. Moreover, each cost estimate is presented to address the hypothetical study range in each TAFA – these estimates should not be aggregated.

The TTIG Final Report was published October 24, 2016.[74]

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[73] The TTIG member organizations include Sacramento Municipal Utility District, California Independent System Operator, Imperial Irrigation District, Los Angeles Department of Water and Power, Silicon Valley Power, Turlock Irrigation District, Modesto Irrigation District, Western Area Power Administration – SNR, San Francisco Public Utilities Commission, Transmission Agency of Northern California, City of Santa Clara, Pacific Gas and Electric Company, Southern California Edison, and San Diego Gas & Electric Company.

[74] RETI 2.0 Transmission Technical Input Group, *Transmission Capability and Requirements Report*, Renewable Energy Transmission Initiative 2.0, October 24, 2016.

ELUTG Report and Data

The Environmental and Land Use Technical Group was charged with providing a high-level overview of the environmental and land-use issues relevant to developing the hypothetical renewable resource range in each area and the conceptual transmission solution identified by the TTIG. To do this, the ELUTG conducted outreach and gathered data, including:

- Environmental (biological and ecological) data.
- Tribal outreach and cultural resources information.
- County land-use planning processes.

The primary environmental work of the ELUTG consisted of selecting the spatial data relevant to the RETI 2.0 planning exercise, evaluating data completeness, identifying data gaps, and determining next steps to fill data gaps and build on existing data. With technical and science support from the Conservation Biology Institute (CBI), Energy Commission staff led an environmental and land-use stakeholder process aimed at compiling available data, evaluating the existing data, and making recommendations on how to best use the results. Through a series of public workshops, smaller group Web conference meetings, and staff outreach/collaboration, the project team compiled and vetted the assembled environmental and land-use data, while building on work that has been done for the DRECP, the San Joaquin Valley Solar Study, and other relevant local planning processes. A product of this work is the RETI 2.0 Gateway, (https://reti.databasin.org), a customized, map-based data sharing and collaboration platform based on Data Basin technology developed by CBI.

The CNRA and Energy Commission also consulted with tribal entities to gather input concerning RETI 2.0. Those tribes that indicated interest in RETI 2.0 provided Energy Commission cultural resources staff with varied input. Several tribes requested additional information and continued consultation, expressed interest in tribal energy development, and identified environmental concerns (including tribal cultural resources). A brief overview of tribal concerns and cultural resources issues pertinent to each TAFA are noted in Appendix A, and Part of this report includes recommendations for next steps.

In addition to tribal outreach, the Energy Commission used the TAFAs to prioritize outreach to planning staff from 28 counties. In July 2016, the ELUTG held a public meeting focused on gathering county land-use information for renewable energy and transmission development. Representatives from Imperial, Kern, Yolo, San Bernardino, and Lassen Counties presented at the public meeting. In addition to gathering county information at the ELUTG public meeting, RETI 2.0 worked directly with counties through phone calls and email messages to gather additional county input and information.

The final ELUTG report was published November 9, 2016, and is an input to the TAFA assessments.[75]

Western Outreach Project Report

The Western Interstate Energy Board accepted a request to support the RETI 2.0 effort by reaching out to western states and stakeholders outside California and producing an input report to the RETI 2.0 Plenary Group — a task referred to as the Western Outreach Project Report (WOPR). The WOPR sought to collect input from western stakeholders regarding the availability of renewable energy and electric transmission that could contribute to meeting California's renewable energy and GHG reduction goals.

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[75] RETI 2.0 Environmental and Land Use Technical Group, *Environmental and Land-Use Information to Support the Renewable Energy Transmission Initiative (RETI) 2.0 Process,* California Energy Commission, Report CEC-700-2016-007, November 2016.

The WOPR summarizes the feedback of stakeholders, including state and federal agencies and regulators, public and private utilities, transmission system operators and developers, generation developers, and members of the environmental advocacy communities. This feedback is organized around a series of focus questions soliciting stakeholders' views on renewable resource potential, cost, and commercial interest, demand for renewable energy, and transmission capability and constraints.

The report also focuses in on the set of current proposals for new transmission in the western region that would help deliver new renewable generation to California. The WOPR provides a high-level framework to compare capacity, costs, renewable resource and export opportunities, and other system benefits of the 12 different project proposals identified.

The WOPR also included several categories of recommendations for California and other western energy stakeholders to consider for next steps. These include updating the out-of-state renewable energy resource and transmission cost assumptions used in California planning tools, addressing perceived barriers in California policy, and continuing regional collaboration in resource planning, energy markets, and transmission service.

While the WOPR summarizes feedback resource potential and interest and pending transmission proposals, it did not include an assessment of the environmental and land-use implications of energy generation or transmission development beyond noting the permitting status of current transmission proposals.

The final *RETI 2.0 Western Outreach Project Report* was published October 28, 2016.[76]

US BLM Consultation Regarding Federal Section 368 Corridor Designation

Section 368 of the federal Energy Policy Act of 2005 directed the Secretaries of Agriculture, Commerce, Defense, Energy, and the Interior to designate West Wide Energy Corridors on federal land in 11 western states that identify the preferred locations for the development of energy transport projects. Nearly 6,000 miles of energy corridors were designated on lands administered by the U.S. Forest Service (FS) and Bureau of Land Management (BLM). These locations were selected to avoid significant known resource and environmental conflicts, promote renewable energy development in the West, improve reliability, relieve congestion, and enhance the capability of the national grid to deliver electricity.

In 2012, the agencies agreed to periodic review of the Section 368 corridors and to consider the revision, deletion, or addition of corridors. BLM is currently leading the interagency energy corridors review for Region 1 that includes Southern California, southern Nevada, and western Arizona (to be completed in mid-2017) and will lead the Region 5 Review (Northern California and northwestern Nevada) in 2018.

At the request of the RETI 2.0 staff, BLM and Argonne National Lab staff reviewed the potential transmission constraints identified in Part 3 of the PRD and the conceptual transmission solutions suggested by the TTIG to identify where overlaps between these conceptual solutions and designated Section 368 energy corridors do and do not exist. The team provided a map of potential overlap (Figure 3-2) and a description of the potential land-use permitting issues identified in each federal corridor. This information contributed to the TAFA Information in Appendix A, the summaries in Tables 2-1 and 2-2, and the description of potential transmission constraints and conceptual solutions described in Part 3. This information is also published along with the Plenary Report as *Appendix B: Section 368 West Wide Energy Corridor Information.*

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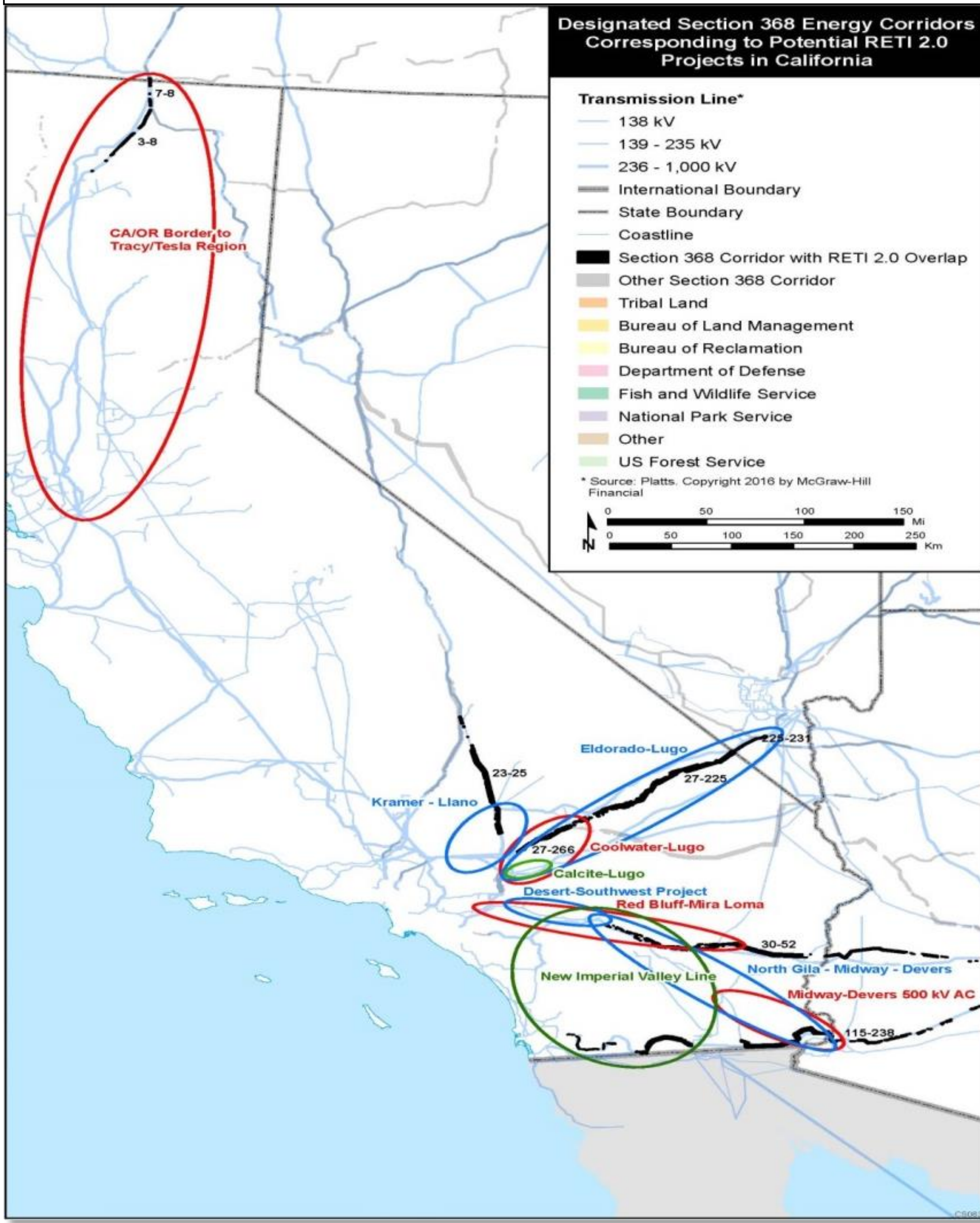
[76] Western Interstate Energy Board, *RETI 2.0 Western Outreach Project Report,* Prepared by Energy Strategies, LLC; October 28, 2016 (revised version).

Figure 3-2: Designated Section 368 Energy Corridors Corresponding to RETI 2.0-identified Conceptual Transmission Mitigation



Source: US BLM and Argonne National Laboratory

Other Sources
In addition to the data and assessment contained in each Input Group report, RETI 2.0 staff and consultants used an array of existing studies and plans to develop the TAFA assessments in Appendix A. These sources include landscape-scale studies covering broad regions, local renewable energy planning efforts, and a review of local general plans and ordinances as they relate to renewable energy.

In response to the PRD, stakeholders stressed the importance of noting the wide diversity in data completeness and quality from which this assessment is drawn available in the different TAFAs. In the Southern California desert region, many of the transmission, environmental, land-use, and cultural issues are relatively well-documented and reflected in existing transmission system studies and land-use plans, due to both experience gleaned from multiple project proposals and proactive landscape-scale planning efforts, including the DRECP and county land-use planning. The DRECP in particular has generated detailed and specific science and information, and the plan is regulatory in nature for renewable energy development on BLM lands. These data have also guided final regulatory land-use designations for renewable energy in Imperial, Inyo, and Los Angeles Counties and draft designations in Riverside and San Bernardino Counties.

In contrast, the Northern California TAFAs, including the Sacramento River Valley and Lassen/Round Mountain area, have not been subject to a comprehensive study of environmental, land-use, and cultural resources and most counties have not undertaken renewable-specific land-use designations. Due to both the lack of landscape-scale planning and the dearth of recent project-specific siting studies, only high-level biological resource data are available, and there are widespread gaps in species and habitat data, notably for avian species.

Between the two planning extremes of the Southern California TAFAs and Northern California TAFAs, the San Joaquin Valley has been subject of a recent effort to gather and assess environmental and land-use data in the *A Path Forward* report.[77] Using the best available data, stakeholders identified important environmental, land-use, and cultural data and assembled data sets and logic models to apply to land-use decision-making. The process led to the informal identification of potential “least conflict lands” but did not analyze potential conflicts on important energy resource areas or analyze environmental tradeoffs outside least conflict areas. While the data, models, and least-conflict lands can inform land-use planning, the effort has not yet resulted in any official land-use designations for renewable energy.

In-State and Import-Export TAFA Summaries

The following section provides an overview of each TAFA in a high-level summary table. The table provides conclusions regarding the renewable energy development potential and the possible environmental and land use feasibility and transmission implications of developing the hypothetical study range proposed by the Plenary Group for each TAFA. A more complete description of issues for each TAFA is presented in Appendix A. Because the characterization of complex issues in short summaries can be incomplete, RETI 2.0 stakeholders reviewed the draft assessments presented in the PRD and suggested some specific edits, as well as overarching caveats.

[77] *A Path Forward: Identifying Least-Conflict Solar PV Development in California's San Joaquin Valley* (San Joaquin Valley Solar Study.

Table 2-2. Summary Characteristics of In-State TAFAs				
TAFA	**Renewable Energy Resources**	**Environmental/Land-Use Considerations**	**Transmission Considerations**	**Conclusions**
Imperial Valley	▪ Abundant solar and geothermal resources ▪ Developed wind energy in western Imperial County. Some wind energy resources in eastern Imperial County. ▪ On-line: 2,079 MW ▪ Proposed or under construction (REAT): 1,349 MW ▪ ISO Interconnection Queue: 2,027 MW	▪ BLM DRECP designated 110,000 acres of DFAs. ▪ Imperial County designated 200,000 acres of renewable energy overlay zones. ▪ Important desert habitats ▪ Salton Sea restoration goals ▪ Agriculture priority ▪ Military operation, testing, and training areas ▪ Culturally important resources to Native American tribes	▪ California ISO estimates 523 MW FCDS[78]/1,849 MW EO capacity for imports from Imperial TAFA ▪ IID estimates 2,300 MW export capacity from Imperial TAFA; ▪ Transmission system constraints: East of Miguel and Path 42 ▪ Six solution concepts: $338 million to $2 billion. ▪ Also contributes to Desert Area Constraint	▪ **Hypothetical study range (HSR) of 3,500 MW solar and 1,000 MW geothermal development feasible due to extensive land use planning within TAFA.** ▪ **HSR of 500 MW of wind energy likely not feasible because wind resources are outside of designated areas for renewable energy development.** ▪ **New transmission necessary to deliver full HSR.** ▪ Transmission projects following existing corridors likely most viable, including IID Midway to Devers, and SDG&E conversion of existing North Gila-Miguel line to HVDC.
Riverside East	▪ Abundant solar energy resources and significant wind energy resources ▪ On-line: 1,296 MW ▪ Proposed or under construction (REAT): 2,275 MW ▪ California ISO Interconnection Queue: 2,725 MW	▪ BLM land includes the largest DFA from the DRECP LUPA and largest designated Solar Energy Zone (SEZ) from Western Solar PEIS ▪ Extensive BLM-designated conservation lands for biological and cultural resources, including designations in areas with wind energy resources. ▪ Migratory birds associated with Colorado River flyway ▪ Groundwater may be hydrologically connected to Colorado River. ▪ Abundant prehistoric and tribal cultural resources.	▪ California ISO estimated[79] existing capacity: 2,450 MW FCDS capacity; 4,754 MW EO capacity ▪ Transmission system constraints to full HSR: Desert Area Constraint ▪ Two solution concepts: up to $1B	▪ **Development of the full HSR of 4,000 MW of solar energy is feasible due to extensive land-use planning on BLM land through the DRECP and Western Solar PEIS.** ▪ **HSR of 500 MW-1,000 MW of wind energy likely not feasible** due to environmental and land-use constraints. ▪ Avoidance of culturally significant landscapes is challenging ▪ **Existing transmission can likely deliver lower end of HSR, but higher end may require major new transmission line.** Substantial existing transmission capacity to deliver mix of FCDS/EO resources**.** However, additional generation would contribute substantially to Desert Area Constraint depending on development/imports elsewhere.

[78] This number is subject to change. The ISO 2016-2017 Transmission Plan in progress will provide updated information.

[79] Assumes West of Devers Project upgrades are in place.

Table 2-2. Summary Characteristics of In-State TAFAs				
TAFA	**Renewable Energy Resources**	**Environmental/Land-Use Considerations**	**Transmission Considerations**	**Conclusions**
Victorville/ Barstow	▪ Abundant solar energy resources, scattered pockets of wind energy resource ▪ Geothermal resources near Coso ▪ On-line: 302 MW ▪ Proposed or under construction (REAT): 344 MW ▪ California ISO Interconnection Queue: 1,600 MW	▪ BLM designated DFAs and conservation lands for multiple sensitive species ▪ Moratorium on North of Kramer DFAs pending Mohave ground squirrel ▪ BLM DFAs have little overlap with wind energy resource areas ▪ Abundant prehistoric and tribal cultural resources ▪ Preference in San Bernardino County for community-scale renewable energy; opposition to all but five DFAs ▪ Kern County promoting renewable energy development in Indian Wells Valley ▪ Inyo County designated solar development areas.	▪ California ISO estimated existing FCDS capacity: 1000 MW (north of Lugo) 470 MW (north of Kramer) 400 MW (Calcite-Lugo area) ▪ 2,735 MW EO (east of Pisgah) 470 MW (north of Kramer) ▪ 1,755 MW on LADWP Barren Ridge (already subscribed) ▪ Transmission system constraints on SCE system: South of Kramer 220 kV Calcite-Lugo 220 kV Lugo Transformer banks ▪ Four solution concepts: $34M to $480M	▪ **Reaching total HSR of 4,500 MW of solar energy and 500 MW of wind energy likely not feasible.** ▪ Development feasibility and transmission needs are very sub-area specific within the TAFA. ▪ Land-use planning for solar energy in specific areas on private lands in Kern, Inyo, and San Bernardino Counties, and on BLM DFAs throughout the TAFA. ▪ Wind energy resource areas generally precluded. ▪ Vocal community opposition to utility-scale development ▪ **New transmission corridors environmentally challenging and locally opposed** ▪ Given constraints to developing new transmission lines, advanced conductors and flow control technologies may be important options to accommodate future development.
Tehachapi	▪ Abundant solar energy and wind energy resources ▪ Much of wind energy resource may already be in development ▪ On-line: 5,345 MW ▪ Proposed or under construction (REAT): 4,120 MW ▪ California ISO interconnection queue: 6,752 MW	▪ DRECP LUPA designated DFAs and some conservation ▪ Extensive renewable energy buildout on private lands ▪ Kern County established efficient permitting processes ▪ Los Angeles County ordinance for certain zoning designations, and ban on utility-scale wind ▪ Abundant prehistoric and tribal cultural resources	▪ California ISO estimated existing capacity: 4,500 MW FCDS 5,600 MW EO ▪ HSR not expected to trigger major upgrades. May experience some increased curtailment. ▪ No solution concepts identified.	▪ **Development of full HSR of 4,500 MW of solar energy and 500 MW of wind energy feasible due to county and BLM land-use planning and permitting experience.** ▪ **Existing transmission capacity adequate for HSR of 4,500 MW solar and 500 MW wind.** ▪ Numerous pending proposals may already account for this capacity.

Table 2-2. Summary Characteristics of In-State TAFAs				
TAFA	**Renewable Energy Resources**	**Environmental/Land-Use Considerations**	**Transmission Considerations**	**Conclusions**
San Joaquin Valley	▪ Abundant solar energy resource ▪ On-line: 1,952 MW ▪ Proposed or under construction (REAT): 6,030 MW ▪ California ISO Interconnection Queue: 8,972 MW	▪ One of most important agricultural regions in world ▪ Continuing drought concern ▪ Portions of the region have substantial drainage constraints requiring fallowing of farmland ▪ Diversity in county renewable energy planning ▪ Extensive acreage under Williamson Act contracts ▪ Counties allow some level of development on lower priority farmland ▪ San Joaquin Solar Report identified extensive "least conflict lands"	▪ California ISO estimated existing capacity: 1,823 MW FCDS 3,131 MW EO ▪ Constraints: Fresno Area Constraint, and Los Banos-Gates-Midway ▪ Several upgrades necessary to mitigate 230 kV, 115 kV and 70 kV system constraints at cost of $400M to $500M. ▪ Alternatively, aggregated generation could be connected to new 500 kV system ▪ Advanced technologies may have useful applications	▪ **Development of HSR of 5,000 MW solar energy appears feasible but substantial new transmission investments are necessary** ▪ High resource value and high commercial interest ▪ Possible to avoid high-value environmental, cultural, and agricultural lands ▪ Opportunity for reuse of degraded lands ▪ Multiple upgrades to lower-voltage systems may be expensive for individual projects ▪ Analysis of interconnecting generation directly to the 500 kV system may show efficiencies. ▪ Advanced flow control technologies may be important
Solano	▪ Good solar energy resources ▪ Large technical wind energy potential ▪ On-line: 1,934 MW ▪ Proposed or under construction (REAT): 167 MW ▪ California ISO Interconnection Queue: 749 MW	▪ Important migratory bird and raptor habitat and important bird areas ▪ Impacts to agriculture areas ▪ Potential conflict of wind energy and Travis Air Force Base operations ▪ San Joaquin, Sacramento, and Yolo Counties may allow some renewable energy development on agricultural land ▪ Alameda and Contra Costa Counties focused planning on Altamont Pass to re-power existing wind energy ▪ Solano County prohibits commercial solar and has a wind moratorium north of Highway 12	▪ California ISO estimated existing capacity: Unknown FCDS 880 MW EO ▪ Constraints: Lack of interconnection facilities ▪ One solution concept based on interconnection to 500 kV system: cost unknown	▪ **Development of HSR of 3,000 MW appears unlikely.** ▪ List of potential issues includes environmental, agricultural, military, and scenic and recreation values ▪ Wide diversity among counties regarding potential and interest in utility-scale renewable energy development. ▪ Environmental data missing for some areas. ▪ **Transmission very limited.** ▪ Lack of existing interconnection facilities. ▪ Limited range of transmission solution concepts identified. ▪ Concentrated resource development (e.g. wind area) could connect to new 500 kV system; expense unknown.

Table 2-2. Summary Characteristics of In-State TAFAs				
TAFA	**Renewable Energy Resources**	**Environmental/Land-Use Considerations**	**Transmission Considerations**	**Conclusions**
Sacramento River Valley	▪ Good solar energy resource ▪ Areas of high-quality technical wind energy resource ▪ On-line: 460 MW ▪ Proposed or under construction (REAT): 135 MW ▪ California ISO Interconnection Queue: 499 MW	▪ High-quality agricultural resources and riparian habitat ▪ Important migratory bird and raptor habitat and important bird areas ▪ Many tribal cultural resources near the Sacramento River ▪ Yolo County allows limited development on agricultural ▪ Butte and Colusa Counties have or are considering energy overlay zones ▪ Tehama County has a wind and solar ordinance that allows development on non-Williamson Act lands	▪ California ISO estimated existing capacity: Unknown FCDS 2,100 MW EO ▪ No recent interconnection studies to evaluate FCDS capacity ▪ Constraints: COI fully subscribed and congested Potential impacts to lower voltage systems ▪ Solution concept is fourth COI 500 kV line at potential cost of $2 billion - $4 billion ▪ Options for operational improvements to increase capacity and/or utilization	▪ **Development of HSR of 3,000 MW is likely not feasible because of limited environmental and land-use planning** ▪ **Transmission for full HSR is not feasible due to COI congestion.** ▪ Little commercial interest or experience with renewable energy development to date ▪ Environmental information missing for some areas. ▪ Some counties have expressed interest in further energy planning or are in the process of planning for renewable energy ▪ Little transmission study information available; TTIG doubtful that there is much existing capacity. ▪ New COI line not studied; may be challenging and costly ▪ Energy-only transmission could deliver some
Lassen/Round Mountain	▪ Areas of good solar energy resource ▪ Areas with high-quality wind energy resources ▪ Known geothermal resource areas ▪ On-line: 229 MW ▪ Proposed or under construction (REAT): 58 MW ▪ California ISO Interconnection Queue: 247 MW	▪ Extensive federal land ownership ▪ Biological resources including greater sage grouse ▪ Many protected areas within USFS lands ▪ Tribal members concerned with preservation of cultural landscapes ▪ Shasta, Lassen, Siskiyou, and Modoc Counties have specific renewable energy plans but not much recent experience with planning and permitting utility-scale renewable energy	▪ California ISO estimated existing capacity: Unknown FCDS 1,250 MW EO ▪ No recent interconnection studies to evaluate FCDS ▪ Constraints: COI fully subscribed and congested Potential impacts to lower voltage systems ▪ Solution concept is fourth COI 500 kV line at potential cost of $2 billion - $4 billion ▪ Reno-Alturas line is of limited value unless COI expanded ▪ Options for operational improvements to increase capacity and/or utilization	▪ **Development of HSR of 3,000 MW is likely not feasible because of limited environmental and land-use planning** ▪ **Transmission for full HSR is not feasible due to COI congestion.** ▪ Little commercial interest or experience with renewable energy development to date ▪ Environmental information missing for some areas. ▪ Some counties have expressed interest in further energy planning or are in the process of planning for renewable energy ▪ Little transmission study information available; TTIG doubtful that there is much existing capacity. ▪ New COI line not studied; may be challenging and costly ▪ Energy-only transmission could deliver some

Table 2-3. Summary Characteristics of Import-Export TAFAs				
TAFA	**Renewable Energy Resources**	**Environmental/Land-Use Considerations**	**Transmission Considerations**	**Conclusions**
California-Oregon Intertie (COI)	▪ Access to abundant Northwest hydro and wind ▪ Some Oregon geothermal ▪ Access to large potential markets for California oversupply	▪ Environmental implications of COI expansion not studied ▪ Small overlap with Section 368 Corridors ▪ Not known whether existing corridors could accommodate new lines. ▪ Expansion of COI could involve substantial permitting challenges	▪ COI already cannot deliver all possible northwestern imports and northern California hydro ▪ Solution concept is fourth COI 500 kV line at potential cost of $2 billion - $4 billion ▪ New transmission elsewhere could increase COI capacity ▪ Options for operational improvements to increase capacity and/or utilization.	▪ **HSR of 2,000 MW additional import not feasible without new 500 kV line from OR border to Tracy area** ▪ New line challenging long-term prospect ▪ New transmission elsewhere in West and dynamic line rating may increase capacity ▪ Regional coordination in resource planning, scheduling, and power products could increase utilization ▪ Some conditional firm/EO capacity may be available
Path 76 (Reno-Alturas)	▪ Wind and geothermal in Lassen and Modoc Counties ▪ Geothermal in northern Nevada	▪ Overlap with Section 368 corridor ▪ New transmission through Lassen National Forest would be challenging	▪ Line faces current constraints on both Reno and Alturas ends ▪ In addition, deliveries subject to California-Oregon Intertie	▪ **HSR of 500 MW not feasible due to constraints at Reno and Alturas** ▪ Imports subject to COI constraint ▪ New transmission challenging
Path 24 (Reno-Truckee)	▪ Geothermal in northern Nevada	▪ Narrow rights-of-way along scenic corridors and through national forest	▪ Small weak system ▪ NV Energy upgrades near Reno may increase capacity marginally	▪ **HSR of 500 MW not feasible due to constraints at Reno and low-capacity line** ▪ New transmission challenging
Path 52 (Owens Valley)	▪ Solar in southwestern Nevada ▪ Geothermal in northern Nevada	▪ Substantial overlap with Section 368 corridor	▪ Imports affect constraint at Kramer ▪ Nevada energy export study in 2012 proposed conceptual 750-1000 MW capacity 500 kV line at est. cost of $600 million	▪ **HSR of 500 MW not feasible due to low-capacity line and constraints at Kramer** ▪ New transmission potentially feasible yet costly

Table 2-3. Summary Characteristics of Import-Export TAFAs				
TAFA	**Renewable Energy Resources**	**Environmental/Land-Use Considerations**	**Transmission Considerations**	**Conclusions**
Path 46 (Eldorado/ Marketplace)	▪ Imports from Nevada, Arizona, and across the West ▪ Access to major markets in Southwest, Mountain West, and potentially Northwest	▪ Several extensive Section 368 corridors ▪ May be confined space for new rights-of-way in and around Eldorado Valley	▪ Up to 7,500 MW of new transmission currently proposed to deliver to Eldorado ▪ Constraint: Desert Area Constraint @ 5,500-8,500 MW additional generation/import ▪ Two separate solution concepts: up to $1B cost	▪ **HSR of 3,000 MW additional import is achievable** ▪ If substantial development or imports in other TAFAs, could trigger Desert Area Constraint and require major new transmission line within California
Path 46 (Palo Verde/Delaney)	▪ Imports from Arizona, Nevada, and across the West ▪ Access to major markets in Southwest	▪ Partial overlap with Section 368 corridors	▪ At least 5,000 MW of capacity currently proposed to deliver power through Palo Verde area ▪ Constraint: Desert Area Constraint @ 5,500-8,500 MW additional generation/import ▪ Two separate solution concepts: up to $1B cost	▪ **HSR of 3,000 MW additional import is achievable** ▪ If substantial development or imports in other TAFAs, could trigger Desert Area Constraint and require major new transmission line within California
Baja California Norte (BCN)	▪ Significant geothermal resources – the 570 MW Cerro Prieto facility one of world's largest ▪ High-quality wind in La Rumorosa area ▪ Energia Sierra Juarez wind project (155 MW) came online in 2015. Connected to SDG&E by generation-tie rated at 1,250 MW capacity.	▪ Not evaluated	▪ Not evaluated by TTIG ▪ BCN grid operated independently; plans to connect to national grid in 2017 ▪ Relatively weak connections to San Diego and Imperial Valley ▪ New cross-border transmission requires Presidential Permit ▪ Energia Sierra Juarez connected to SDG&E system at ECO by 230 kV generation-tie line. Total capacity is 1,250 MW. ▪ IID is exploring 300-600 MW connection to CFE through Fern substation in Imperial Valley ▪ New imports through ECO or Imperial Valley subject to East of Miguel constraint	▪ **Near-term opportunity to increase wind energy from La Rumorosa area up to 1,000 MW, but requires East of Miguel solution** ▪ Ongoing Mexico energy sector reform, national energy strategy (incl. renewable goals), and North American Partnership, plus specific plans by CENACE to integrate BCN to national grid and explore EIM, suggest opportunities may develop further in coming years.

Western TAFAs Summary

- **Renewable Resources**
  - The WOPR generally confirmed the resource potential and commercial interest in the western TAFAs. The WOPR quantified thousands of MWs of geothermal, wind, and solar projects in varying stages of development across the West.
  - The WOPR did not survey environmental and land-use information in depth but noted that many generation and transmission projects are in advanced stages of land-use permitting.
- **Existing Transmission**
  - Firm transmission capacity for new imports is very limited.
  - There may be some capability to deliver Northwest wind or Nevada geothermal to COI, but there is very limited capability to deliver New Mexico wind or Arizona/Nevada geothermal to California.
  - Conditional firm transmission service from most areas is more available but rarely used.
  - Roughly 3,000 MW of long-term export capacity to Northwest markets through the COI and BPA systems is available.
  - There are several transmission challenges to long-term export of California oversupply to the Southwest, including lack of west-to-east path ratings and capacity east of Phoenix.
- **Export Market Opportunities**
  - The WOPR noted that export to the Southwest may be hindered by the growth of solar in Arizona, Nevada, and New Mexico, creating abundance of supply during many of the same hours.
  - Northwest export markets may be more complementary during much of the year, if transmission and power market arrangements are available. During the spring, however, both California and the Northwest expect to be in oversupply conditions.
  - The WOPR discussed the potential for long-term, intra-day power-exchange arrangements between California and Northwest utilities that could send California oversupply north to displace fossil or hydroelectric generation, and return hydro generation to meet evening or morning ramps.
  - Commenters noted the complexity of the Northwest hydro system, however, and advised that any California-Northwest renewable resource exchange would require careful study.
- **Resource Changes**
  - Environmental regulations and the increasing impacts of climate change are requiring changes to hydroelectric operations that may have impacts on generation and exports to California, and on Northwest utilities' appetite for imports from California.
  - The retirement of coal-powered electricity generators may a) make available formerly subscribed transmission capacity, b) affect capacity and reliability of transmission system-wide, and c) enhance markets for California oversupply.
- **Proposed Transmission:**
  - The WOPR described 12 transmission projects proposed across the West that propose to help deliver renewable energy to California. These projects are summarized in Table 2-4.
  - Several projects propose to deliver power directly from high-quality wind resource areas to a California interconnection using high-voltage direct current technology (Transwest, Zephyr, Centennial West).
  - Several projects propose to connect one or more renewable resource-rich areas to the existing transmission network using high-voltage alternating current technology.

Summary Table of Pending Transmission Proposals and Combinations

Transmission options identified through the Western Outreach Project offer a range in the capabilities to deliver out-of-state renewable energy to California. The WOPR compiled information on the estimated transfer capacities to California that could be achieved through various configurations. The estimated capacity to deliver to California (MW) and the cost per MW of added capacity (as a range between the developer's estimate and a WECC TEPPC calculator tool estimate) are shown in Table 2-3. For several options, the ability to schedule delivery to California is identified as contingent on the availability of transmission capacity on the existing system. Also shown are the potential renewable energy resources that could be imported and potential markets for exports of California renewable energy.

Table 2-4. Configurations and Cost Considerations for Western Transmission Projects

Resource Area Developer / Project Name	Length (miles)	Estimated Capacity (MW)	Cost Range ($million per MW)	Contingent on Existing OOS Transmission Capacity?	Potential Import/Export Opportunities
Wyoming					
TransWest Express (HVDC)	730	3,000	1.00 to 1.07	No; Interconnects with California ISO.	Import: WY wind Export: PACE
DATC Zephyr HVDC	850	3,000	1.07 to 1.17	No; Interconnects with California ISO.	Import: WY wind Export: PACE
DATC Zephyr HVDC (to IPP)	525	1,900	1.05 to 1.35	No; Interconnects with LADWP.	Import: WY wind+storage Export: CAES storage
Wyoming, Nevada, Utah, Idaho					
PacifiCorp Gateway South, and TransCanyon Cross-Tie	613	1,500	1.05 to 1.43	Yes; Contingent on delivery from Robinson Summit	Import: WY wind; UT solar/wind/geo Export: NVE, PAC
PacifiCorp Gateway West, and LS Power SWIP North	1275	1,500	2.21 to 2.47	Contingent from Robinson Summit	Import: WY wind; NV geo Export: NVE, PAC, IPCO
PacifiCorp Gateway (full), and LS Power SWIP North, and TransCanyon Cross-Tie	1888	1,500	3.25 to 3.90	Contingent from Robinson Summit	Import: WY wind; NV geo; UT solar/wind; NW wind and geo Export: NVE, PACE, BPA
New Mexico, Arizona					
Hunt Power, Black Forest Partners Southline	370	1,000	0.80 to 0.93	Contingent from Saguaro/Tortolita	Import: NM wind; AZ solar Export contingent
Southwest Power Group SunZia	515	3,000	0.67 to 0.71	Contingent from Pinal Central	Import: NM wind; AZ solar Export contingent
Cleanline Centennial West HVDC	900	3,500	0.71 to 1.25	Interconnects with California ISO.	Import: NM wind Export: PNM
Lucky Corridor LLC Lucky Corridor	130	700	0.22 to 0.34	Contingent from Four Corners	Import: NM wind No export
Cleanline Western Spirit	140	1,000	0.20 to 0.25	Contingent from Four Corners	Import: NM wind No export
Arizona					
SDG&E Southwest Powerlink HVDC Conversion	165	750	1.27 to 3.23	Internal to California ISO	Import: AZ solar Export: APS

APS = Arizona Public Service; BPA = Bonneville Power Administration; CAES = Compressed Air Energy Storage; IPCO = Idaho Power Company; NVE = NV Energy; PACE = Rocky Mountain Power

Source: Table 5, Table 6, and Table 7, WOPR

Part 3. Potential Transmission Constraints and Conceptual Solutions

The TTIG and RETI 2.0 stakeholders identified several potential transmission constraints in California and along the major import-export paths that could limit the delivery of additional renewable energy. The TTIG, RETI 2.0 stakeholders, and the RETI staff identified potential solutions at a conceptual level – including new transmission, advanced technologies and non-wire alternatives, and operational efficiencies – that could address these constraints. This section discusses these potential constraints and conceptual solutions in detail.

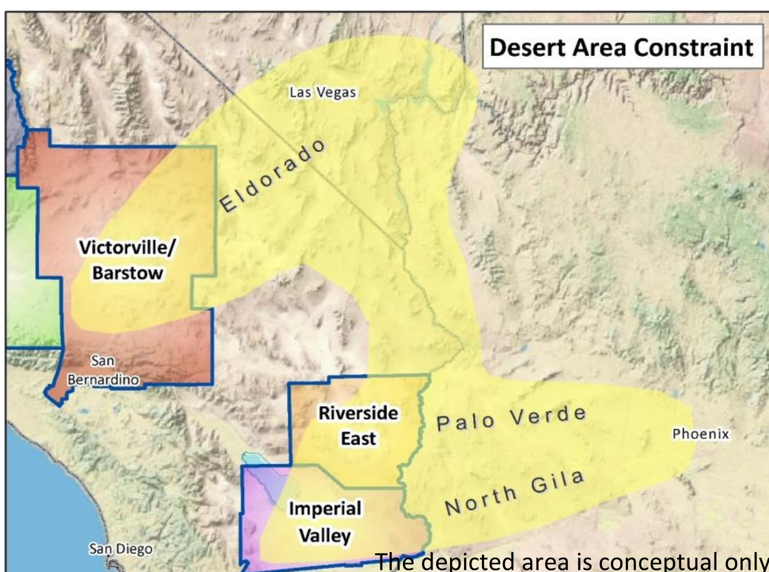
The potential constraints and conceptual solutions identified here are informational only. These conclusions do not include specific recommendations for further action, and they are not intended to be adopted within a regulatory proceeding. Rather, these conclusions are intended to be used by federal, state, and local policy makers as they consider future planning efforts – including environmental and land-use planning, procurement planning, and transmission planning at the state and regional scales. For instance, US BLM has indicated it appreciates this analysis as it continues the review of Section 368 Corridors. CPUC, ISO, and regional planning entities may wish to study the issues raised here in further detail in the IRP and TPP planning processes. Renewable energy and transmission developers may also consider these conclusions in their prospective planning for new development.

Desert Area Constraint

The Desert Area Constraint (DAC) was identified as a potentially significant issue during the assessment of multiple TAFAs. The DAC affects deliverability of resources from a broad area in southeastern California. This constraint affects new renewable generation that could be developed in the Victorville/Barstow, Riverside East, and Imperial TAFAs, as well as imports from throughout the West that could be delivered through either the Eldorado or Palo Verde import/export paths along WECC Path 46. Because of the breadth of area and low-cost renewable resources affected and the advanced degree of both commercial interest and land-use planning in these areas, the DAC should be a priority for further planning.

Prior studies have indicated that several combinations of contingencies and limiting facilities may constitute this constraint depending on the resource development mix. Among these limitations, the most critical ones involve the Lugo – Victorville 500 kV line overload following several potential contingencies. Previous assessments have indicated that an upgrade of the 15-mile 500 kV line segment between SCE's Lugo Substation (southwest of Hesperia) and LADWP's Victorville Substation (north of Victorville) would mitigate this constraint and provide roughly 2,000 MW of additional capacity.

Figure 3-1. Area Contributing to Desert Area Constraint



Source: Aspen Environmental Group

LADWP, SCE, and California ISO are coordinating on this upgrade.

The second limitation arises when considering incremental generation beyond these 2,000 MW in the same area encompassing the Victorville, Riverside East, and Imperial TAFAs, as well as imports from the Eldorado or Palo Verde area. The limiting constraint is a potential overload of the 500 kV lines between the Valley, Alberhill, and Serrano substations. This constraint may be encountered at incremental generation levels as low as 2,000-4,000 MW if concentrated in Riverside East or between 5,500 and 8,500 MW if dispersed among these TAFAs.

Figure 3-1 illustrates the approximate area that may contribute to the DAC. This figure is a conceptual representation of the footprint of this constraint and does not indicate the exact locations that may contribute to the constraint. The degree to which new generation affects the DAC depends on the location of generation interconnection.

For instance, the Lugo-Victorville constraint is most affected by generation and imports into the Eldorado area in the Victorville/Barstow TAFA—and, to a lesser extent, by generation in Riverside East, imports over the Palo Verde corridor and generation in Imperial Valley. In contrast, the Valley-Alberhill-Serrano constraint is less affected by generation and imports into the Eldorado area and generation in Imperial Valley compared to generation in Riverside East, and imports over the Palo Verde corridor.

California ISO interconnection cluster studies have determined that the likely mitigation for the DAC is **either** (i) a new series compensated 500 kV line between the Mira Loma substation in the Inland Empire and the Red Bluff substation near Desert Center **or** (ii) a new 500 kV line between the Eldorado and Lugo substations. The TTIG estimates the order-of-magnitude cost of either of these new lines at roughly $1 billion.

Tables 3-1 and 3-2 summarize the corridor segments by transmission components and potential land-use concerns. These corridors (Mira Loma-Red Bluff and Lugo-Eldorado) also align with many areas where Section 368 Energy Corridor designations exist; these corridors offer locations where agency coordination could be promoted and energy infrastructure could be most efficiently concentrated.

Commenters to the PRD noted that the conceptual solutions identified by the TTIG and described above do not include other potential conceptual solutions to the DAC. Of particular note are the role advanced technologies – notably power flow control and advanced conductors – could serve in increasing capacity on existing corridors, and the impact of new transmission outside the central corridor of the DAC, including the Imperial Valley proposals described below. These commenters supported a more focused and fuller exploration of these alternatives in a DAC-focused scenario modeling exercise as described in Part 4.

Table 3-1. Mira Loma–Red Bluff Transmission Corridor

Corridor	Length	Existing Voltage, Circuits	Land-Use Issues
Red Bluff to Devers Substation Section 368 Corridor: 30-52	70 miles	500 kV 2 circuits on separate structures	■ Desert segment: mix of BLM and private land ■ Long-established Devers-Palo Verde corridor ■ Likely feasible to site a third 500 kV circuit except in a small area just southeast of Devers Substation where homes are at ROW edges

Table 3-1. Mira Loma–Red Bluff Transmission Corridor

Corridor	Length	Existing Voltage, Circuits	Land-Use Issues
Devers to Vista Substation (500 kV line would not interconnect with Vista Substation but would pass around it) No Section 368 Corridors	40 miles	220 kV 3 circuits on 2 sets of structures*	■ Approved West of Devers Upgrade leaves space in most of existing ROW for a new 500 kV line ■ Challenging to site in the 3 miles east of Vista Substation and at Vista Substation due to dense residential areas and narrow 220 kV ROWs ■ Challenging to site 500 kV structures around Vista Substation due to numerous existing circuits entering/exiting substation
Vista to Mira Loma Substation No Section 368 Corridors	14 miles	220 kV 3 circuits (2 to Mira Loma, 1 to Etiwanda)	■ Much of the length of the existing corridor is fully occupied by 3 sets of structures (220 kV and likely 115 kV). ■ Existing structures would have to be removed, relocated, consolidated, or reconfigured to allow space for a 500 kV line ■ This is likely feasible and is similar to the recently approved West of Devers Upgrade Project configuration

* CPUC approved the West of Devers Upgrade project for this segment in August 2016; it will result in upgraded 220 kV capacity and consolidation of circuits to 2 sets of structures.

Table 3-2. Lugo-Eldorado Transmission Corridor

Corridor	Length	Existing Voltage, Circuits	Land-Use Issues
Eldorado Sub. to Barstow or Pisgah Section 368 Corridors: 225-231, 26-266, & 27-225	~110 miles	6 500 kV circuits (originating at Lugo and Victorville) 2 230 kV circuits	■ These corridors are occupied by several important transmission lines that import power from Hoover Dam and other generators. Upgrades would require study of potential ROW expansion, avoidance of new ROW on NPS land, consideration of DRECP conservation designations, and potential rebuilding of existing lines. ■ Section 368 Corridor 225-231 (Nevada, near Eldorado Valley) crosses critical habitat for desert tortoise. ■ Section 368 Corridor 27-225 matches (Victorville-Eldorado) nearly the full length of one of the potential upgrade corridors without intersecting the Mojave National Preserve. The western 35 miles crosses fragmented BLM jurisdiction with intervening non-federal ownership. ■ Section 368 Corridor 27-225 also crosses critical habitat for desert tortoise and bighorn sheep in several locations. It also intersects and is adjacent to multiple ACECs and DWMAs (Mojave Fringe-toed Lizard, Afton Canyon, Cronese Basin, Shadow Valley DWMA, Clark Mountain, Ivanpah DWMA).
Barstow to north of Victorville	33 miles	(above)	■ Section 368 Corridor 27-266 passes through land primarily managed by BLM, with scattered low density residential areas and off-road recreational areas.
Victorville to Hesperia (Lugo Sub.)	15 miles	(above)	■ Between Victorville and Lugo Substations, the lines cross private lands with expanding residential land uses. ROW expansion in this area may be challenging due to these adjacent land uses and public opposition, but several existing ROWs exist.

Source: Aspen Environmental Group and US BLM

Imperial Valley

The constraints to delivery of Imperial Valley resources are a combination of physical and technical limits, along with policy, economic, and accounting issues among the multiple transmission systems that interconnect in the valley — Imperial Irrigation District, San Diego Gas & Electric Company and Southern California Edison (operated by California ISO), and the Western Area Power Administration.

One issue that IID has raised as potentially impacting development of renewable generation in the IID portion of the Imperial TAFA is the California ISO's determination and allocation of maximum import capability[80] from IID into the California ISO system. This technical and policy issue has been and continues to be discussed in multiple venues. This report does not make any conclusion about this issue.

According to IID, an important distinction to make in discussing Imperial Valley transmission capacity is the location of generation. The power from generation that interconnects to transmission closer to the southern part of the valley will flow predominantly to the west, toward San Diego load centers. Power from generation closer to the Salton Sea and north Imperial Valley will flow predominantly to the north and west, toward SCE's system and the Los Angeles basin. Thus, it is useful to discuss the transmission constraints and potential solutions to those constraints, to the south and to the north separately.

Several options have been proposed to address each of these barriers in recent years. These solutions include several new transmission proposals.

In 2014, at the request of the California ISO, the California Energy Commission commissioned a series of reports from Aspen Environmental Group that provided a high-level assessment of the environmental feasibility of several electric transmission alternatives under consideration by California ISO in response to the closure of the San Onofre Nuclear Generating Station (SONGS) in June 2013.[81] In the main report and two subsequent addenda,[82,83] 13 conceptual transmission options were identified and evaluated. Several of these transmission options either connect directly with Imperial Valley locations or otherwise substantially affect deliverability from Imperial Valley.

Also in 2014, the California ISO conducted a stakeholder consultation on options to address renewable generation deliverability out of Imperial County in support of the California ISO's 2014-15 transmission

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[80] *Maximum import capability* (MIC) is the quantity of energy that is estimated to be deliverable through each intertie into the ISO balancing authority area. The MIC is determined based on ISO study criteria. See https://bpmcm.caiso.com/BPM%20Document%20Library/Definitions%20and%20Acronyms/BPM_for_Defintions_and_Acronyms_V16_Redlined.pdf.

[81] Lee, Susan, Brewster Birdsall. (Aspen Environmental Group). 2014. *Transmission Options and Potential Corridor Designations in Southern California in Response to Closure of San Onofre Nuclear Generating Stations (SONGS): Environmental Feasibility Analysis.* California Energy Commission. Publication Number: CEC-700-2014-002.

[82] Lee, Susan, Emily Capello. (Aspen Environmental Group). 2014. *Addendum to Transmission Options and Potential Corridor Designations in Southern California in Response to Closure of San Onofre Nuclear Generating Station (SONGS): Environmental Feasibility Analysis.* California Energy Commission. Publication Number: CEC-700-2014-002-AD.

[83] Lee, Susan, Brewster Birdsall. (Aspen Environmental Group). 2014. *Second Addendum to Transmission Options and Potential Corridor Designations in Southern California in Response to Closure of San Onofre Nuclear Generating Station (SONGS): Environmental Feasibility Analysis.* California Energy Commission. Publication Number: CEC-700-2014-002-AD2.

planning process.[84] This process included discussion of several transmission options identified by Aspen in its work for the Energy Commission.

As described in the final TTIG report and presented in Appendix A for the Imperial TAFA, the conceptual solution options for the Imperial TAFA include, but are not limited to, six transmission projects that would support increased renewable energy export from the Imperial Valley. Each project is summarized below, with a highlight of the associated economic, environmental, and electrical implications and Section 368 corridors (where appropriate). The use of existing designated Section 368 Energy Corridors could promote agency coordination and would consolidate energy infrastructure by following existing transmission lines and pipelines.

Projects That Address Primarily the Southern System Constraints:

- **SDG&E North Gila–Miguel Conversion to DC**[85] Given that this proposed project entails conversion of the existing 500 kV Southwest Powerlink, it would present minimal new environmental or routing concerns. The project would deliver up to an incremental 1,000 MW of capacity from North Gila or Miguel substations. The HVDC technology would help alleviate local inertia and reliability concerns in the San Diego region and would reduce Imperial Valley and San Diego local capacity requirements. By providing an additional path into San Diego, the project would help solve loop flow issues and strengthen reliability for SDG&E, IID, Comisión Federal de Electricidad (CFE), Arizona Public Service, and WAPA. Finally, it would increase import capacity from the Imperial Valley by 500-1,000 MW, import capability from wind resources in Baja California Norte, and could increase export opportunities for excess solar and other renewable energy resources from California.

  This route falls primarily within Section 368 Corridor 115-238, and there are tribal and environmental constraints. However, the conversion for alternating current (AC) to direct current (DC) would have minimal ground disturbance or visual changes, aside from the new converter stations.

- **SDG&E Imperial Valley–Valley 500 kV**[86]: A new 500 kV line would span roughly 165 miles from the Imperial Valley substation, north and west along the western side of the Salton Sea, to the northwest through Coachella Valley to the existing Devers substation, and then into the Valley substation near Romoland. However, defining a new 500 kV corridor may be difficult through urban areas like Mecca, Thermal, and Coachella, as well as tribal lands. Adding a third 500 kV line between Devers and Valley would be challenging due to tribal land, homes near the corridor, and National Forest wilderness. Such a line could provide a major new path for relieving congestion not only within Imperial Valley, but on the Eco-Miguel line into San Diego and imports from the Palo Verde hub and Mexico. The order-of-magnitude cost of such a line is estimated at $2 billion. There is no Section 368 Corridor along the western side of the Salton Sea or through the Coachella Valley.

[84] California Independent System Operator, Imperial County Transmission Consultation, Draft Second Discussion Paper, October 1, 2014.

[85] HVDC Conversion of Southwest Powerlink RETI 2.0. John Jontry, Huang Lin. http://docketpublic.energy.ca.gov/PublicDocuments/15-RETI-02/TN213496_20160906T113111_Panel_3_Presentation__John_Jontry_and_Huang_Lin.pdf. Sept. 1, 2016.

[86] This route was not studied in the Aspen SONGS reports, but the segment from Imperial Valley to La Quinta is assumed to follow Alternative 12 route evaluated in http://www.energy.ca.gov/2014publications/CEC-700-2014-002/CEC-700-2014-002-AD2.pdf.

Proposals Addressing Primarily the Northern System Include:

- **IID Midway-Devers** At a total length of 84 miles, this proposed new 500 kV line would require acquisition of new ROW across agricultural lands, scattered BLM lands (including some small areas of DFAs in Imperial County at the base of the Chocolate Mountains Aerial Gunnery Range), and through Riverside County/BLM Mecca Hills Wilderness Area. The route would join the Red Bluff-Devers corridor near Interstate 10, possibly requiring additional ROW as that corridor passes north of Indio and into the Coachella Valley fringe-toed lizard preserve and Thousand Palms.

  Section 368 Corridor 30-52 (along I-10) would match up to 14 miles of this route. There are no 368 Corridors along the eastern side of the Salton Sea. Environmental concerns include crossing the Coachella Valley preserves and habitat for Coachella Valley fringe-toed lizard and other desert species.

- **IID North Gila–Midway-Devers** (~154 miles). For 2 miles west of out the North Gila Substation (north-east of Yuma, AZ), this route would cross high-value agricultural lands, then across the Colorado River into California. At the California border, the route would either pass into Fort Yuma tribal land (for about 9 miles) or would have to turn north to avoid the tribal land, staying on BLM land and in a federally designated Section 368 energy corridor. The route would parallel a railroad ROW for about 45 miles to the IID Midway Substation, much of it within BLM land now designated as conservation, where transmission may not be allowed. From the Midway Substation to Devers, the description above would apply, including the 368 Corridor overlap along the I-10 segment as described for the IID Midway-Devers line above.

- **IID Hoober-SONGS HVDC**[87] This alternative to the Midway-Devers options envisions a new HVDC substation at Hoober near the Salton Sea and a new HVDC line to the site of the decommissioned San Onofre Nuclear Generating Station. The use of HVDC would provide various operational flexibility and voltage stability benefits to the greater Los Angeles area. The existing ROW east of Salton Sea for IID's 230 kV Midway-Devers line provides a corridor option to Devers, but routing around high-value agricultural land, homes, and tribal land would be needed. From Devers to SONGS, some underground HVDC segments could be required in urban areas. Expansion of SDG&E ROW through the Marine Corps Base at Camp Pendleton may present a challenge. The order-of-magnitude cost is estimated at $2 billion.

- **Desert Southwest Transmission Line.** Originally approved by the BLM in September 2006, this route closely follows the SCE 500 kV corridor between the Colorado River Substation (southwest of Blythe), Red Bluff Substation (southeast of Desert Center), and Devers Substation. The BLM portions are fully authorized, but the status of easements across portions of private land is unknown. This project is outside the Imperial Valley but would improve deliverability from the Imperial Valley. This line is almost entirely within Section 368 Corridor 30-52, following the SCE Devers-Palo Verde 500 kV route segment from Devers to the Colorado River Substation.

Finally, stakeholders suggested that advanced grid technologies may be particularly applicable to address Imperial Valley issues, in particular, advanced power flow control to relieve congestion and improve power deliverability.[88]

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[87] This route was evaluated as Alternative 9 in the Aspen SONGS report at http://www.energy.ca.gov/2014 publications/CEC-700-2014-002/CEC-700-2014-002-AD.pdf.

[88] Smart Wires Comments on July 29 TTIG meeting; August 8, 2016; http://docketpublic.energy.ca.gov/PublicDocuments/15-RETI-02/TN212672_20160808T125200_Smart_Wires_Comments_Smart_Wires_Comments_on_July_29_TTIG_meeti.pdf.

In addition to the effect on the deliverability from the Imperial Valley, each project will also need to be evaluated for reliability, economic benefits, and the deliverability of additional renewable energy from Arizona and Mexico. Each could have impacts on improving flows, affecting the Desert Area Constraint, and in accessing both renewable energy resources and markets for excess California generation.

California-Oregon Intertie

The California-Oregon Intertie (COI) includes three 500 kV lines, which extend from the Oregon border to the Redding area, and then to the Tracy area south of Sacramento. These lines, with a combined path rating of 4,800 MW, are operated in parallel with several 230 kV lines connected to several hydroelectric plants in Northern California. The lines are owned by multiple parties, including WAPA, PG&E, PacifiCorp, and several public utilities operated as the Transmission Agency of Northern California (TANC). There are two 368 Corridor segments (7-8 and 3-8) in this area within National Forest system lands, but they are discontinuous and include relatively small percentages of the potential new line length that would be needed.

TTIG members reported there was limited transmission capacity from the Northern California TAFAs. California ISO reported that because there have been very few interconnection studies in the region, there is insufficient information to determine whether any latent capacity is available, while TANC reported that the COI is fully subscribed and heavily utilized during much of the year.

The COI is a historically congested path. Operating and planning studies (including those done by the COI Operating Studies Subcommittee [OSS] and the California ISO during 2015 and 2016) indicate that it is not possible to simultaneously deliver 4,800 MW over the COI facilities and the 4,200 MW of hydroelectric capacity to load centers in Northern California. This suggests that new generation could not achieve full capacity deliverability status, and the interconnection of new firm deliverability resources in Northern California would require transmission upgrades.

It is possible that energy-only resources could be interconnected, though such new resources would likely have to be curtailed to mitigate post-contingency overloads, at least during spring and summer months.

In 2010-11, the diverse owners of the COI convened the Transmission User Group to examine the historical utilization of the path and potential future capacity.[89] While the users agreed that the path is generally fully subscribed, and entities that need firm (guaranteed) delivery of energy will need new transmission capacity, they also agreed that utilization of the COI is very seasonal; highly dependent on factors such as weather, hydro conditions, and loads within each region; and driven mainly by the price spread between the two regions, which at a minimum must cover variable costs associated with transmission wheeling and losses.

The ISO's *Annual Report on Market Issues & Performance* regularly shows significant transmission congestion on the COI interties. In the 2015 report,[90] the ISO reported that the two COI interties were congested an average of 22 percent in 2013, 31 percent in 2014, and 24 percent in 2015.

To provide new firm and fully deliverable capacity from either Northern California generation or import/exports from the Northwest, the TTIG concluded that an additional 500 kV AC line from the California-Oregon Border to the Tracy/Tesla area would be needed. There have not been recent, concrete proposals to construct any such projects. It is not known whether the existing ROW corridors utilized for the COTP

[89] Transmission Utilization Group COI Utilization Report. May 4, 2011.

[90] California ISO, *2015 Annual Report on Market Issues & Performance*.

and PACI are capable of accommodating more lines, in keeping with California's Garamendi Principles.[91] Permitting for new or expanded ROW would encounter siting challenges through National Forest lands and the Sacramento Valley. In the absence any such detailed proposal, the TTIG proposed a "ballpark" conceptual estimate of $2 billion to construct a new 300-mile, 500 kV transmission line.

In addition to building new transmission, RETI 2.0 stakeholders identified several non-wire alternatives to overcoming the constraints on the COI. As discussed, energy-only resources could prove potentially economic, particularly if the generation profile proved complementary to the current seasonal and intraday patterns on the COI. Re-conductoring could increase total capacity in the same ROW, and advanced flow technologies could potentially address some overload contingencies. Moreover, new transmission development elsewhere in the western region that relieved loop flow on the COI could also relieve congestion and increase capacity.

Finally, marketing and operating innovations by utilities and marketers utilizing the COI could improve the efficiency of utilization by (a) identifying complementary resource patterns and exploring potential long-term power purchase/trading agreements; (b) developing and standardizing day-ahead power market products that take advantage of predictable daily flows (for example, "duck belly" and "duck neck" products); (c) making better use of shorter-term transmission schedules, dynamic scheduling[92], and conditional firm[93] transmission service.

Reno-Alturas Line (Path 76)

Another identified constraint that affects resource development in Northern California is the Reno-Alturas transmission line that connects the NV Energy system near Reno and the BPA system near Alturas, California. The 368 Corridors 8-104 and 15-104 are designated along much of this segment, and a parallel corridor in Nevada also connects (Corridors 16-17 and 16-104).

NV Energy has proposed transmission projects to relieve the binding constraints on the Nevada end of this line, potentially creating incremental capacity. However, it is unlikely that a significant amount of load in Reno or elsewhere in the region will support delivery of a significant amount of new generation from Lassen/Modoc Counties.

Central and Northern Sierra Paths

Path 76, Alturas: a 345-kV line that crosses northeastern California, from the NV Energy system in Reno, through Lassen County into Modoc County, where it connects with the BPA system near Alturas.

Path 24, Truckee: a 60-kV and 115-kV system that connects the NV Energy system in Reno with the PG&E system in Truckee, generally following Interstate 80. Lines continue across the Sierra Nevada, west into the PG&E territory north of Sacramento.

Path 52, Owens Valley: a 55-kV interconnection between the SCE system north of Inyokern with the Valley Electric Association, along the eastern boundary of Nevada.

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[91] The Garamendi Principles, based on SB 2431 of 1988, encourage the use or expansion of existing rights-of-way for new transmission. See http://www.energy.ca.gov/2010publications/CEC-600-2010-007/CEC-600-2010-007-D.PDF.

[92] *Dynamic scheduling* allows a generator to move some or all of its generation from the host balancing area and place it in another balancing area (BA). Thus, the non-host BA controls the generation as though it was physically in its BA.

[93] *Firm transmission service* is guaranteed against interruption, while *nonfirm transmission service* anticipates some level of interruption or curtailment. *Conditional firm transmission service* specifies the extent or conditions of interruption. See http://www.eia.gov/electricity/data/eia411/nerc_glossary_2009.pdf.

For delivery to the Bay Area and other California load centers, power flow studies and TANC indicate that generation interconnecting to the Reno-Alturas line in Northern California will have a similar impact on the COI transfer capacity as other generation interconnecting to the PG&E 230 kV system elsewhere in Northern California. According to TANC, any additional generation in this area could negatively impact the COI transfer capacity. Regardless of whether capacity exists on the Reno-Alturas line, firm transmission capacity is not available on the COI to deliver power from Alturas to California load centers.

The Lassen Municipal Utility District (LMUD) submitted comments to RETI 2.0 in May 2016[94] indicating interest in developing a double-circuit 230 kV line to interconnect the Reno-Alturas line from Susanville to the California ISO grid at Cottonwood. The exact routing for this line was not identified, but according to the project description, it appears that at least some areas of new ROW corridor may be required in the Lassen National Forest. A line with this capacity would likely allow the delivery of 500 MW to the California grid. However, if the new line connected at Cottonwood, it would likely still face the same constraints to the COI transfer capability. These constraints would still require new capacity from the interconnection point south to the Tracy area.

Reno-Truckee (Path 24)

The TTIG report states that the energy transfer capability of Path 24 is limited due to transmission constraints in the Reno area. The transfer capability of the line depends on the load profile in the Reno area. NV Energy has approved upgrades to the relevant system in Nevada, which may marginally improve import/export capacity to California. Section 368 Corridor 6-15 follows the existing lines, but it is discontinuous due to nonfederal land crossings.

Since the 1980s, several conceptual “TransSierra” projects to upgrade this path have been considered but not pursued. Conceptual projects have been proposed in the past for the potential to import Nevada’s geothermal power into California and strengthen the transmission grid in central Nevada and improving regional loop flows. However, challenges to upgrading the existing 60 kV and 115 kV lines in this corridor include extensive residential properties near the corridors, Scenic Corridor status to Interstate 80, and environmental impacts in National Forest lands. These smaller lines often have narrow rights-of-way, so upgrading to higher voltage lines that require wider corridors could be challenging.

Owens Valley (Path 52)

The existing 115 kV system from VEA to SCE in the Owens Valley is relatively weak. In 2012, the Nevada Energy Assistance Corporation (NEAC) proposed a conceptual 290-mile, 500 kV line from west central Nevada (Nye County) west to south of Bishop, and south through the Owens Valley to the Antelope substation.[95] The proponents indicated that the project could allow imports of Nevada geothermal and solar energy and generation from the Owens Valley/Ridgecrest area to be delivered to a less congested part of the SCE system at Antelope. The NEAC report estimated the capacity of the line at 750-1000 MW for an incremental cost of $500 million to $600 million. In comments to the PRD, Ormat Inc. also noted the potential of converting the existing 230 kV Oxbow generation-tie line in this region into an ISO network resource. Neither of these proposals has proceeded beyond the conceptual stage.

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[94] Lassen Municipal Utility District Comments: Lassen and Round Mountain Transmission Assessment Focus Area (5/12/2016).

[95] Nevada Energy Assistance Corporation; *Transmission Initiative Routing Study*; TriSage Consulting, EnergySource, and US Geomatics; February 2012.

There is a discontinuous Section 368 Corridor (18-23) from east of Mono Lake, south to Ridgecrest. This corridor holds LADWP and SCE lines.

San Joaquin Valley

The original high-end of the proposed hypothetical study range for the San Joaquin Valley was a maximum of 10,000 MW of new solar development, based on an assessment of raw resource potential and the 213,000 acres of lands that could potentially be considered "low-conflict" with environmental and land-use values, according to the San Joaquin Solar Report.[96] However, the TTIG reported that it would not be possible to estimate the transmission implications of such a large amount of additional generation because it is far beyond any level that has been studied.

At the relatively smaller, but still substantial, hypothetical study range of 5,000 MW, the TTIG estimated that a new transmission line would not be required, but substantial upgrades would be necessary to the existing transmission system(s) in the San Joaquin region. The TTIG did suggest conceptual alternatives to the potential upgrades that could be needed, depending on whether new generation was dispersed and connected to the 115 or 230 kV network, or could be concentrated and connected to the 500 kV system. The former could be more expensive in total but is likely to be more amenable to incremental additions over time and in response to different projects. The latter may be more efficient and cost-effective but would require either project aggregation or proactive planning.

Commenters to the PRD noted that since the publication of the TTIG report, the approval process for the proposed Central Valley Power Connect (also known as Gates-Gregg 230 kV project) has been provisionally suspended due to higher-than-expected energy efficiency and behind-the-meter PV growth, which have reduced reliability- and economic-driven transmission needs. Since the TTIG report assumed the approval of the CVPC, it is not known what effect this suspension would have on the potential constraints and conceptual solutions identified here.

North of Kramer

The SCE Kramer Substation, near the intersection of state Highways 395 and 58 in San Bernardino County, aggregates electricity generated at Coolwater Generating Station (gas-fired generation, no longer operational after January 15, 2015[97]), the LUZ solar trough facilities (San Bernardino County), and the Coso geothermal field in Inyo County. In addition, SCE's 115 kV line from Inyo County brings hydroelectric power into the substation. Power flows south in two 220 kV circuits to the Lugo Substation. While there is some existing capacity (less than 500 MW) in the north of Kramer system, it is likely to be used by generation already under development; so further renewable generation north of Kramer would exacerbate the south of Kramer 220 kV constraint.

The potential construction of solar projects in the water-constrained agricultural lands in Kern County's Indian Wells Valley would require transmission capacity to the south: either through Kramer to the Victorville and Lugo Substations or along the LADWP 230 kV lines to LADWP's Barren Ridge and Haskell Substations. The Indian Wells agricultural areas are equally accessible to both transmission systems, with SCE's on the east and LADWP's on the west. Assuming that the LADWP system will be fully utilized by LADWP's own renewable portfolio, the most likely requirement for developing Indian Wells solar

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[96] Pearce, Dustin, James Strittholt, Terry Watt, Ethan N. Elkind. *A Path Forward Identifying Least-Conflict Solar PV Development in California's San Joaquin Valley*; Center for Law, Energy & the Environment (CLEE), May 2016; https://www.law.berkeley.edu/wp-content/uploads/2016/05/A-PATH-FORWARD-May-2016.pdf.

[97] http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M152/K058/152058507.PDF.

becomes improvements to the SCE system, from Indian Wells to the Inyokern Substation just south of the agricultural area (east of the intersection of Highways 395 and 178), then to Kramer and Lugo.

The TTIG report states that generation development in the SCE North of Kramer area could create overloads on the Kramer-Victor lines. This could be addressed with either of the following new transmission projects:

- A new **Coolwater-Lugo** 220 kV line, consisting of a new 34-mile 220 kV line from the existing Coolwater 220 kV Substation (at the now-closed CGS east of Barstow), south to the Lugo-Pisgah corridor (north of Lucerne Valley), and 28 miles of tear down and rebuild from the proposed Calcite Substation (north of Lucerne Valley) west to the Lugo Substation. SCE proposed this project in 2013 but cancelled it when several generation facilities in the north of Kramer area retired, making additional transmission capacity available. In May 2015, the CPUC dismissed the project without prejudice,[98] requiring that the already-acquired environmental data be maintained for potential future use. The proposed new transmission project was highly controversial and faced substantial public opposition in the communities of Barstow, Lucerne Valley, Apple Valley, Victorville, and Hesperia. The Coolwater-Lugo corridor follows 368 Corridor 27-266 to the north side of Victorville, then passes through about 15 miles of private land into Lugo Substation.
- A new **Kramer-Llano** 500 kV line, requiring new 500 kV facilities at Kramer Substation, a new 40-mile 500 kV line heading south from Kramer Substation (within Section 368 Corridor 23-25 for about 17 miles), and a loop into the existing Lugo-Vincent No. 2 500 kV line near the community of Llano (about 15 miles east-southeast of Palmdale). The area between Kramer and Llano is primarily private land, but there are discontinuous BLM parcels along the east side of Highway 395, and Edwards Air Force Base would have to be consulted to ensure that no conflict is created with its flight operations. Scattered low-density residential areas exist north of Llano and east of Adelanto. Commenters to the PRD noted that while still subject to opposition, the conceptual Kramer-Llano line would be a preferable "last resort" alternative to the Coolwater-Lugo concept.

Stakeholders also suggested that the use of advanced grid technologies, including re-conductoring with advanced conductors or the use of flexible AC technologies, could relieve the north of Lugo constraints.

[98] http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M152/K058/152058507.PDF.

Part 4: Recommendations for Further Planning

Scenario Concepts to Inform Resource and Transmission Planning

Background

The impetus behind the RETI 2.0 project is partly to help inform potential scenarios that California energy planners should consider for both resource procurement and transmission planning.

While development of resource portfolios for regulatory purposes — including the approval of renewable resource procurement under the CPUC's authority or the approval of transmission need under the ISO's Transmission Planning Process — requires rigorous analysis and thorough stakeholder review, the informal RETI 2.0 process has also identified several general scenario concepts that could guide the development of more specific portfolios.

During the RETI 2.0 process – including in Plenary Group workshops, TTIG public workshops and the Western Outreach Project – stakeholders discussed several issues that would benefit from further assessment through scenario studies. In the PRD, these issues were grouped into scenario concepts, and stakeholders were asked to comment on whether and how these scenarios should be used in regulatory planning.

Stakeholder comments to the PRD generally, though not universally, supported exploring the issues identified in the scenario concepts and suggested clarifications and refinements, as well as potential applications in private and public planning.

These recommendations are intended primarily to inform resource planning at the CPUC and Energy Commission and transmission planning at the ISO. They may also inform the resource and transmission planning of the POUs and WestConnect and interregional planning conducted under FERC Order 1000.

Existing Capacity Scenario Concepts

The PRD proposed that utilities, the CPUC and ISO should study scenarios of future renewable resource procurement and transmission that focused on utilizing the existing capacity of the current transmission system. Several comments supported using scenario analysis to explore an "optimal" mix of FCDS and EO status renewable resources. Other comments suggested extension of this scenario concept to include other utilization-enhancing operational agreements such as conditional firm transmission service.

The TTIG and RETI 2.0 stakeholders confirmed that there is, in the aggregate, sufficient existing available transmission capacity to interconnect and deliver a substantial amount of new renewable generation in several areas of the state. Among the TAFAs reviewed by the TTIG, nearly 11,000 MW of capacity are available in the aggregate for fully deliverable resources, or potentially twice as much (more than 23,000 MW) of energy-only resources. The ELUTG and RETI 2.0 stakeholders also confirmed that substantial renewable energy development potential and commercial interest exist in areas that have engaged relatively advanced land-use planning efforts to facilitate renewable energy development and minimize environmental and land-use impacts.

These preliminary results suggest that the state's utilities may be able to achieve many, if not all, of their RPS obligations with existing transmission. This relative abundance in the aggregate, however, may mask specific limits in specific areas. One potential source of such limits may be in the interplay between deliverability status (FCDS and EO) and the energy and capacity value provided by specific renewable resources in specific areas. A business-as-usual approach may rapidly "consume" FCDS capacity with low-cost solar resources that provide relatively little resource adequacy (RA) value, while higher RA-value renewable resources that may be developed in the longer term would require new transmission to achieve FCDS status, with implications for the total amount of new transmission that may be required. Alternatively, there may be a more optimal mix of FCDS and EO interconnection for different renewable energy types in each TAFA that could maximize the efficient utilization of existing capacity.

The PRD proposed that the planning agencies (CPUC, Energy Commission, and ISO) examine these issues with scenarios that test different renewable energy portfolios against a different mix of deliverability status in each area, and the effect on the total transmission need. The goal of such scenarios would be to inform whether there is an "optimal" mix of deliverability that maximizes the energy, capacity, and RA values in areas with a mix of renewable resources.

Commenters to the PRD supported the examination of these issues. One opportunity may be in the "40 X 30 Reference Scenario" being developed within the IRP proceeding at the CPUC. As of December 2016,[99] staff at the CPUC is developing a proposed modeling framework that optimizes each year's procurement of renewable resources based on minimizing the total costs and benefits of the entire resource portfolio over a 20-year planning horizon. These costs and benefits include the RA and capacity values, and the costs of EO and FCDS delivery status. This model framework could provide insight into the most efficient use of transmission deliverability, among other values.

Desert Area Constraint Scenario Concepts

One of the more robust conclusions of the RETI 2.0 assessment is that there is substantial likelihood that the Desert Area Constraint (DAC) will emerge as a serious issue prior to 2030, given the advanced planning and commercial interest in both additional renewable energy development in southeastern California as well as imports through the region. Addressing this constraint could require more than 100 miles of new transmission infrastructure at a potential cost of $1 billion.

The CPUC, Energy Commission, California ISO, LSEs, and developers could consider studying scenarios that challenge the DAC, to better understand the potential impacts of development in these desert locations, the nature of overloads and other constraints caused by new generation or imports, and the types of solutions that could potentially address them. Multiple commenters on the PRD supported exploring these issues.

While specific portfolios are beyond the scope of the RETI 2.0 project, the information regarding commercial interest and development feasibility gathered during RETI 2.0 would support scenarios that test up to several hundred megawatts of new generation north of Kramer and elsewhere in the Victorville/Barstow TAFA, 1,500-3,000 MW each in Riverside East and Imperial TAFAs, and 3,000-4,500 MW from out-of-state through both the Eldorado and Palo Verde import paths. Such a scenario could provide valuable insights into the magnitude of potential constraints and the effectiveness of conceptual solutions.

A DAC scenario could also be used to test multiple alternative solutions beyond the two conceptual solutions (or Mira Loma-Red Bluff or Lugo-Eldorado) identified by the TTIG. Commenters to the PRD identified and supported examining the effect of alternative projects that may not be primarily directed at resolving the DAC. These include new transmission lines in or through the Imperial Valley (for example, Midway-Devers and SWPL DC Conversion), the potential re-purposing of existing 500 kV lines from Intermountain Power Plant in Utah and Navajo Generating Station in New Mexico, and non-wire alternatives like advanced flow control. Finally, the DAC could also be tested with alternative mixes of

[99] E3, "Resolve Modeling Overview," CPUC IRP Workshop, December 16, 2016.

energy only vs. full deliverability status generation to explore whether a greater mix of energy only status resources could extend the capability of existing transmission and obviate the need for new transmission.

Out-of-State Transmission Scenario Concepts

The PRD suggested that the CPUC IRP proceeding (and Energy Commission and ISO in related proceedings) should develop at least one scenario of 2030 resources and infrastructure that includes expanded out-of-state transmission to examine the potential benefits of these projects. Multiple commenters to the PRD strongly supported further examination and inclusion of OOS system capabilities in IRP scenarios, and suggested a broader array of issues or infrastructure options to include in any scenario. Among these were the better considerations of the availability of existing transmission, through transmission service agreements like conditional firm transmission and additional latent transmission capacity that may be created by retirement of coal generation facilities.

Both the TTIG process and Western Outreach Project identified substantial interest and activity in out-of-state (OOS) transmission development. These transmission projects may offer new network configurations that allow not only access to specific out-of-state renewable options, but a broad array of benefits including access to a diversity of western resources, other markets for export or "diverted imports"[100] during periods of California oversupply, increase in capacity available for EIM transfers, reduction in congestion along the California-Oregon Intertie and along the "California backbone" Paths 15 and 26, and regional reliability and capacity. The PRD recommended that as the CPUC, Energy Commission, and California utilities embark on SB 350 Integrated Resource Planning, they should use scenarios that feature one or more alternative configurations of OOS transmission.

The potential broader system benefits of expanded OOS transmission are not easily assessed in current procurement cost models and procurement-based transmission planning. For instance, in the CPUC's RPS Calculator, new OOS transmission is represented by generic transmission costs to reach specific renewable resource zones (based on the Western Renewable Energy Zones), and broader system benefits are not considered. Many of these potential benefits could be assessed when projects are evaluated in the California ISO TPP; however the selection of projects to evaluate is driven by renewable resource portfolios based on the CPUC and Energy Commission process. The FERC Order 1000 requirements for interregional coordination are also designed to assess some of these values, but this process is not yet mature.

The Western Outreach Project identified 12 OOS transmission project proposals that cite as at least one of the purposes and benefits to connect OOS renewable resources to load in California. More than 3,500 line-miles of new transmission projects with more than 10,000 MW of capacity are in "advanced permitting."[101] In addition to long-distance "delivery" projects between a California intertie and distant Wyoming and New Mexico wind resources, these proposals include significant "network" projects with the variety of potential benefits identified above.

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[100] *Diverted imports* refers to electricity that is otherwise contracted to be delivered to California but is instead re-sold during oversupply periods, either in long-term, day-ahead or real-time transactions, to another utility out-of-state.

[101] For information on the permitting status of these projects, see the WOPR. http://docketpublic.energy.ca.gov/PublicDocuments/15-RETI-02/TN214339_20161102T083330_RETI_20_Western_Outreach_Project_Report.pdf.

The majority of these projects may not necessarily connect directly to a California balancing authority. Both the TTIG and WOPR identified that several contracting or operational arrangements are available – including direct scheduling to the ISO, dynamic schedules, or a pseudo-tie with the balancing authority where the generation is located – for generation to count toward the California RPS as a "Portfolio Content Category 1" resource.[102] Also, as discussed below, potential future EIM or day-ahead market expansion or other operating agreements suggest the benefits from these projects could be realized under a variety of potential futures.

For instance, one potential configuration of OOS transmission that has been studied in some depth[103] includes both the Gateway West and the SWIP North projects, which create a new power pathway from central Nevada north to southern Idaho, and then from Idaho east to the wind resource area of southeast Wyoming. In combination with recent transmission connecting central Nevada to the ISO system in Eldorado Valley (and potentially with Gateway West connecting west to the former Boardman coal plant in Oregon), this configuration could provide access to as much as 1,500 MW of Wyoming wind and Nevada geothermal, while increasing export capacity from California to northwest and southwest load centers and relieving regional congestion on the COI and Paths 15 and 26.

Another example configuration with benefits that are not easily assessed by the current procurement-based model is the proposed Zephyr transmission and compressed air energy storage project combination. This project could combine high-capacity Wyoming wind with large-scale energy storage and controllable HVDC transmission to create a robust and flexible system with oversupply export options.

One consideration raised by commenters on the PRD is the scale of total cost, commitment, or risk used in scenario analysis. These commentators argued for scenarios that study or compare smaller increments of regional renewable energy and transmission capacity in the 500-1500 MW range to reduce portfolio risk, increase resource diversity, and lower the hurdles to aggregated demand.

Finally, another example of potential configurations for further study are those projects that propose to deliver wind energy from New Mexico to existing transmission capacity that may be available as coal units retire in New Mexico and Arizona. Two examples of these projects are the Lucky Corridor and Western Spirit projects. Both projects are relatively short (<150 miles) and located solely within New Mexico but could utilize historical capacity from Four Corners coal generation plant to deliver high-quality renewable resources to the Palo Verde hub.

One planning scenario recommended in the WOPR is identifying a set of advanced development projects. The WOPR identified advanced development projects as those that had (1) received a federal final environmental impacts statement (FEIS) or record of decision and (2) entered Phase 2 or greater of the WECC Path Rating Process. Based on these definitions and the information collected by the WOPR, advanced development projects would include Gateway South and West, Southline, SunZia, SWIP North, and TransWest Express.

Several commenters recommended greater attention to expanding the modeling of OOS transmission that does not depend on new development. These commenters noted that several opportunities for accessing OOS renewable energy resources are not well-modeled by California planning entities. These include the greater use of conditional firm transmission service and operating agreements between BAs (including dynamic scheduling or pseudo-ties), the availability of latent transmission capacity following the retirement of coal generation facilities, and the potential of advanced grid technologies including

[102] Portfolio Content Categories are specified by Senate Bill X1-2 (2011) and Public Utilities Code Section 399.16(b).

[103] As in the Low Carbon Grid Study and SB 350 Regionalization Benefit Study.

flow control, HVDC, and grid-scale energy storage. These commenters stressed the importance of "developing cost and capacity information for these existing infrastructure options so that they can be compared alongside of, and in conjunction with, the proposed transmission projects in Table 2-3."[104]

It is clear from the comments of participants and stakeholders in RETI 2.0 that California agencies could consider a much wider range of potential OOS transmission configurations and the associated attributes in energy accessed, export market opportunities, and congestion and reliability benefits. Because the CPUC, IOUs, and California ISO's efforts to develop GHG-focused IRPs will only allow for the exploration of a few distinct scenarios, stakeholder and party input will be critical to select the most insightful configuration of out-of-state transmission for use in the forthcoming IRP process.

Information on Western Resource Costs

The Plenary Report PRD proposed a recommendation, drawn from the Western Outreach Project Report, that California consider a "request for information" (RFI) process to solicit commercial information from both OOS generation and transmission developers regarding resource costs and transmission cost and configuration. The RFI would ask renewable generation developers to partner with transmission owners or developers to propose commercially viable out-of-state renewable resource options that could help meet California's RPS and GHG goals. The information generated by this RFI would include the "all-in" costs of OOS resources by requiring a specific transmission service proposal along with generation costs. The purpose of the RFI would be twofold: the procurement staff, grid operators, regulators, and others could be exposed to project proposals that would help the utilities in resource planning, California ISO in grid planning, and regulators in costs and scale of out-of-state resources and the associated place in long-term planning.

While commenters supported the goal of the proposed exercise – to generate better understanding of OOS renewable resource and transmission service options, both for regulatory oversight and potential procurement decisions – commenters were generally skeptical that an RFI would be the right vehicle to generate this information. OOS project developers preferred a binding Request for Offer process, while other commenters suggested that substantial information could be gleaned from existing studies (e.g. WOPR, ISO, WECC, WestConnect, NREL) and direct outreach that could be more aggressively synthesized and integrated into the public and private planning frameworks. Commenters didn't specifically suggest an appropriate venue for this synthesis of available information, though the WOPR suggested that the Western Interstate Energy Board's Resource Planners Forum could serve some of these functions.

Environmental, Cultural, and Land-Use Recommendations

During RETI 2.0, the ELUTG worked with a wide variety of stakeholders, Native American tribes, and counties to assemble environmental and land-use information to inform the TAFA-by-TAFA analysis. The environmental track of the ELUTG focused on assembling and presenting planning-level analysis of biological and other related environmental data relevant to TAFAs. Moreover, ELUTG consulted with Native American tribes through targeted outreach to gather input on tribal land and cultural resource concerns within TAFAs. ELUTG worked with county planners to gather input from counties, as well as assemble geographic information regarding local land-use planning for renewable energy development.

Most of the environmental and land-use information was gathered from existing studies and data sources, such as environmental information that was collected for the DRECP. Some information pre-

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[104] CalWEA Comments on the RETI 2.0 PRD (1/10/2017).

sented by the ELUTG was developed during the RETI effort, such as input from Native American tribes and information from counties. However, gaps in environmental and land-use information remain.

In addition to assembling environmental and land-use information, the ELUTG initiated development of a spatial tool — an environmental report writer. Once complete, this environmental report writer can be used to sort and analyze the environmental and land-use information over geographic zones. The tool is being developed to improve energy infrastructure development decisions.

The main goal for the ELUTG was to identify and recommend how the data collected in the RETI 2.0 process should best be used to describe the environmental issues relevant to potential utility-scale renewable energy development in the TAFAs. A primary observation of the ELUTG report is that assembling a complete set of environmental and land-use data, and developing the environmental report writer tool to easily and quickly analyze such data, will better inform planning level analysis for future renewable energy and transmission development.

The recommendations presented below are organized by environmental, tribal and cultural resources, and county.

Environmental Data

The high-level TAFA-by-TAFA analysis relies on known environmental information and does not present any new environmental analysis. The ELUTG report includes a recommendation that RETI 2.0 assemble data sets in the following biological categories for evaluating potential environmental implications at a high planning level:

- Information on species, both the number of species that may be encountered and their sensitivity
- Location of federally designated Critical Habitat
- Information regarding the conservation value of a particular area
- Information regarding the landscape intactness of natural lands and habitats
- Information regarding the presence of important or significant habitat connectivity areas

As presented in Section 2.2 and Appendix A, there are areas throughout the state with data and information that fall within the biological categories identified above. However, there are additional steps that the state should consider to create additional data and information. Such steps should use existing data sets and assemble these data in useful ways to assess areas for potential environmental implications at a landscape-scale level. By consistently applying existing statewide and regional data sets, the state can improve analysis of the conservation value, landscape intactness, and presence of habitat connectivity in areas throughout the state.

This approach and the level of information for many environmental elements are sufficient for an early and high-level look to assess the environmental implications for potential renewable energy and transmission areas. The completion of a fully functional environmental report writer tool, as described in the ELUTG report, could provide a viable way to quickly and effectively use the existing data sets to evaluate potential new renewable energy resource and transmission development areas in a variety of energy infrastructure planning processes.

The ELUTG report identifies recommendations for future work on and improvements to the data sets and features of the environmental report writer. These recommendations can help advance the science and tools necessary to help stakeholders and decision makers proactively plan for renewable energy and transmission while minimizing potential environmental effects.

- Complete and accurate data sets, data logic models, and the environmental reporting tool should be kept available online for use by agencies, stakeholders, and the public.

- Data sets should be kept up to date and important data gaps filled to provide a basic set of information that can be used as an input to agency planning and regulatory processes.
- Agencies and stakeholders should work together to complete the interactive environmental report writer tool that uses the data assembled in landscape-scale planning processes, like RETI 2.0, so that the tool could be easily used in planning and decision making.

Tribal and Cultural Resources

Upcoming transmission and renewable energy planning processes should include continued consultations with tribes and tribal communities. Energy Commission staff is planning a statewide Tribal Energy Summit in 2017, where statewide energy planning and energy development considerations on tribal lands will be discussed. Concerns related to specific development projects and impact assessments will be discussed among tribes and state energy agencies on a project-by-project basis.

Common project planning concerns and cultural resource issues among tribes that are pertinent to RETI 2.0 TAFAs include the following:

- A recurring theme concerning California Native American tribes and tribal communities is that frequent and meaningful consultation is necessary between tribal entities and agencies.
- Cultural resources identification efforts need to take into account traditional tribal land use and values, such that cultural landscapes and other cultural resources that have low or no archaeological presence on the landscape can be identified.
- A third theme, related to the first, is apprising tribes of existing mechanisms and opportunities for engagement in advanced and project-specific planning.
- Re-conductor existing transmission lines to the greatest feasible extent as a means of reducing impacts on natural, cultural, and tribal resources.

Energy Commission staff observes that successful tribal consultation that respects the time and fiscal constraints facing tribes ensues from early consultation that includes rapid follow-up with specific or project-level information. In the context of RETI 2.0 planning, such follow-up would comprise a map or maps depicting potential transmission projects and corridors. While early tribal consultation is necessary, even at the conceptual planning level, often the best use of tribes' time and resources (and maximum benefit of the consultation) comes from providing tribes with specific information to which they can respond.

County Land-Use Planning

RETI 2.0 was able to gather information from several counties in the northern and southern portion of the state, though the information for all 28 counties that fall within the TAFAs is incomplete. As described in Section 2 and Appendix A, RETI 2.0 county outreach included counties from the San Joaquin Valley and Northern California; however, local land-use information for TAFAs in those portions of the state is incomplete. To fully describe how land uses throughout the state may affect renewable energy development, additional land-use information, where available, should be included in high-level planning.

Section 2.1 describes the differences between the two types of county land-use information that RETI 2.0 collected. As presented, some county land-use information can be displayed geographically, like the renewable energy overlay zone in Imperial County. Other county land-use information cannot be easily displayed geographically because the land-use rules and policies are criteria-based, like those being contemplated in San Bernardino County. For high-level planning analysis, like RETI 2.0, it is simpler to present land uses geographically because the information can be easily incorporated with other geographic information, like transmission system information, that may affect how and where renewable energy projects develop. Nevertheless, not all counties plan for renewable energy by designating areas or geographies for development because some counties find that a criteria-based approach works better for regulating renewable energy development within their county. To fully understand how county land-use information may affect development, it is important to understand that differences exist between how counties plan for and regulate renewable energy development and that some information is simple to present on maps, while other information is better presented in text form.

The following specific recommendations should be considered for future energy planning activities:

- When feasible, future high-level planning for renewable energy and transmission should continue to include local land-use information. Such information should be gathered through an iterative process with counties so that the information accurately reflects county land-use rules and policies.
- The energy agencies should continue to assist counties with local land-use planning to facilitate renewable energy generation and transmission by providing data and tools that assist with planning, decision making, and stakeholder engagement.