Biennial RPS Program Update

In Compliance with Public Utilities Code Section 913.6

January 1, 2016

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INTRODUCTION

Background

In April 2011 Governor Edmund G. Brown signed Senate Bill (SB) 2 (1X) (Simitian, 2011) codifying California's longstanding 33 percent Renewables Portfolio Standard (RPS) goal. In addition to increasing the state's RPS goal from 20 percent in 2010 to 33 percent by 2020, SB 2 (1X) added Section 913.6 to the Public Utilities Code (Pub. Util. Code).[1] Senate Bill 350 (De León, 2015) revises the current RPS target to obtain 50 percent of total retail electricity sales from renewable resources by December 31, 2030, with interim targets of 40 percent by December 31, 2024, and 45 percent by December 31, 2027.

Section 913.6 requires the California Public Utilities Commission (CPUC or Commission), in consultation with the California Energy Commission (CEC), to report to the Legislature by January 1 of every even-numbered year on all of the following: (a) the progress and status of RPS procurement; (b) the status of permitting and siting RPS resources and transmission facilities; (c) the projected ability of each electrical corporation to meet the RPS requirements pursuant to the cost limitations established by Section 399.15(d), and (d) barriers to, and recommendations for achieving the RPS requirements. The complete text of Section 913.6 is provided as Appendix A.

To gather data and other information for this report, Energy Division staff relied upon publicly available data already submitted to the Commission by electrical corporations, in addition to consulting with CEC staff.

This is the second report to the Legislature made pursuant to Section 913.6,[2] referenced hereafter as the Section 913.6 RPS Report. Section 913.6 applies to retail sellers as defined in Section 218. As such, Energy Division staff has included procurement updates for California's three large Investor-Owned Utilities (IOUs), the California Small and Multi-Jurisdictional Utilities (SMJUs), Community Choice Aggregators (CCAs), and Electric Service Providers (ESPs).

This report focuses on recent accomplishments and the current status of RPS procurement, RPS resources, and transmission. Thus, while SB 350 has been approved, due to timeframe that this report covers, this report will focus on efforts to achieve the 33 percent renewables. As the Commission moves forward to implement SB 350 and the RPS program transitions to the 50 percent requirement, the broad policy issues discussed in this report will apply to a 50% RPS program. Additional information about the challenges and solutions the Commission anticipates in implementing a 50% RPS program can be found in Energy Division's staff white paper, "Beyond 33% Renewables: Grid Integration Policy for a Low-Carbon Future."[3]

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[1] All further references to sections refer to the Pub. Util. Code unless otherwise specified.

[2] This report was formerly submitted pursuant to Section 399.19. SB 697 (Herzberg, 2015)

[3] The Beyond 33% Renewables: Grid Integration Policy for a Low-Carbon Future paper can be found at: www.cpuc.ca.gov/NR/rdonlyres/8F428686-2FB5-4F3D-85B3-0475694E4718/0/Beyond33PercentRenewables_GridIntegrationPolicy_Final.pdf

Summary

Below is a brief summary of the report:

- The three large IOUs are expected to reach all of their Compliance Period 2 (2014-2016) RPS requirements based on confidential Renewable Net Short (RNS) information submitted with their 2015 RPS Procurement Plans (RPS Plans). Those IOUs collectively served 26.6% of their 2014 retail electricity sales with renewable power:
  - 28.0 percent for Pacific Gas and Electric Company (PG&E)
  - 23.2 percent for Southern California Edison Company (SCE)
  - 36.4 percent for San Diego Gas and Electric Company (SDG&E)
- Many renewable energy generation and transmission projects have successfully received all of their necessary permits or are in the late stages of the permitting process. Due to key environmental permitting initiatives taken on by regulatory agencies across California, project viability risk from permitting has decreased.
- Proactive steps are being taken by the IOUs, regulatory agencies, and market participants to ensure that RPS compliance requirements are met in the future.

RPS PROCUREMENT

> Section 913.6(a)
>
> *[This Report shall contain] The progress and status of procurement activities by each retail seller.*

RPS Progress and Status

Table 1 provides a summary of all retail sellers' RPS-eligible positions relative to their overall retail sales both in 2014 (actual sales data) and 2020 (based on IOU forecasts).[4] Currently, the Large IOUs are forecasted to have contracted enough RPS-eligible resources to meet both their RPS compliance obligations in the second compliance period (2014-2016) and their 33 percent RPS compliance obligations by 2020.

Additionally, Table 1 shows that most of the CCAs, SMJUs and ESPs are significantly below their 2020 33% RPS requirements. Most of these smaller RPS obligated entitles procure the majority of their RPS-eligible resources through short-term transactions made at the end of a compliance period. For the same reason, the ESPs' 2014 data has been redacted to maintain the confidentiality of their short-term portfolio management strategy.

Table 1. **California Retail Sellers' RPS Progress and Status**

		2014 Actuals (GWh)			2020 Forecast (GWh)		
	Name of Retail Seller	2014 Retail Sales	2014 RPS procurement	2014 RPS Procurement %	2020 Retail Sales	2020 RPS procurement	2020 RPS Procurement %
Large IOU	PG&E	74,546	20,894	28.0%	59,668	22,051	37.0%
	SCE	75,828	17,618	23.2%	74,687	27,529	36.9%
	SDGE	16,467	6,002	36.4%	16,726	7,209	43.1%
CCA	Lancaster	-	-	-	554	30	5.4%
	MCE	1,254	646	51.5%	1,910	463	24.3%
	Sonoma Clean Power	581	257	44.4%	2,406	658	27.4%
SMJU	PacifiCorp	754	136	18.1%	710	117	16.5%
	CalPECO	538	118	22.0%	645	209	32.4%
	BVES	126	32	25.9%	167	51	30.9%

[4] For details on individual retail sellers, *see* IOUs' 2014 RPS Compliance Reports.

Table 2 (Continued). **California Retail Sellers' RPS Progress and Status**

		2014 Actuals (GWh)			2020 Forecast (GWh)		
	Name of Retail Seller	2014 Retail Sales	2014 RPS procurement	2014 RPS Procurement %	2020 Retail Sales	2020 RPS procurement	2020 RPS Procurement %
ESP	3 Phases RPS	Confidential	45	Confidential	250	-	0.0%
	Calpine	Confidential	245	Confidential	991	0.3	0.0%
	Constellation	Confidential	1,202	Confidential	5,500	9	0.2%
	Commerce	Confidential	34	Confidential	172	2	1.2%
	Commercial	Confidential	12	Confidential	65	0.1	0.2%
	Direct Energy Business	Confidential	820	Confidential	-	30	-
	EDF	Confidential	23	Confidential	679	0.03	0.0%
	Gexa	Confidential	74	Confidential	-	-	-
	Liberty Power Holdings	Confidential	1	Confidential	-	1	-
	Noble	Confidential	1,202	Confidential	5,400	1	0.0%
	Pilot Power Group	Confidential	310	Confidential	1,546	9	0.6%
	Palmco Power	-	-	-	-	-	-
	Shell	Confidential	876	Confidential	201	5	2.5%
	TNG	Confidential	3	Confidential	3	0.05	1.4%
	UC System	Confidential	-	Confidential	263	155	58.8%

Table 2 provides a summary of the three large IOUs' (PG&E, SCE, and SDG&E) RPS progress over the past ten years and average RPS costs for each IOU.[5], Overall, these IOUs have increased the amount of RPS-eligible generation as a percentage of their overall generation portfolio.

Table 2. **IOU RPS Compliance Progress and Cost Information, 2005-2014**

		Actuals									
IOU	**Data Input**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**
PG&E	Retail Sales (GWh)	72,372	76,356	79,078	81,524	79,624	77,485	74,864	76,205	75,705	74,546
	RPS Generation (GWh)	8,908	9,080	9,034	9,824	11,497	12,359	13,920	15,131	17,652	20,894
	RPS Procurement (%)	12.3%	11.9%	11.4%	12.1%	14.4%	16.0%	18.6%	19.3%	23.3%	28.0%
	RPS Expenditures ($, thousands)	551,874	575,483	671,317	790,116	791,870	893,010	1,017,030	1,198,832	1,662,654	2,237,594
	RPS Costs (dollars per MWh)	61.95	63.38	74.31	80.42	68.88	72.26	73.06	79.23	94.19	107.09
SCE	Retail Sales (GWh)	74,994	78,863	79,505	80,956	78,048	75,141	73,778	75,597	74,480	75,828
	RPS Generation (GWh)	12,715	12,382	12,163	12,291	13,034	14,344	15,171	14,992	16,444	17,618
	RPS Procurement (%)	17.0%	15.7%	15.3%	15.2%	16.7%	19.1%	20.6%	19.8%	22.1%	23.2%
	RPS Expenditures ($, thousands)	968,003	932,421	976,870	1,138,145	1,032,716	1,172,088	1,299,941	1,230,432	1,436,844	1,630,892
	RPS Costs (dollars per MWh)	76.13	75.30	80.31	92.60	79.23	81.71	85.68	82.07	87.38	92.57
SDG&E	Retail Sales (GWh)	16,002	16,847	17,056	17,410	16,994	16,283	16,249	16,627	16,164	16,467
	RPS Generation (GWh)	825	900	881	1,047	1,784	1,940	3,380	3,416	4,702	6,002
	RPS Procurement (%)	5.2%	5.3%	5.2%	6.0%	10.5%	11.9%	20.8%	20.5%	29.0%	36.4%
	RPS Expenditures ($, thousands)	40,219	44,832	42,886	55,726	95,965	109,275	142,866	256,245	362,556	563,468
	RPS Costs (dollars per MWh)	48.73	49.84	48.69	53.20	53.78	56.34	42.27	75.01	77.09	93.87

[5] *See* IOUs' 2015 RPS Procurement Plans.

PERMITTING AND SITING

> Section 913.6(b)
>
> *[This Report shall contain] The status of permitting and siting eligible renewable energy resources and transmission facilities necessary to supply electricity generated to load, including the time taken to permit each eligible renewable energy resource and transmission line or upgrade, explanations of failures to meet permitting milestones, and recommendations for improvements to expedite permitting and siting processes.*

Introduction

Permitting is an essential step in securing a project site and successfully developing an RPS project. Many different regulatory bodies oversee the permitting of generation and transmission projects in California. The CEC is responsible for permitting thermal power plants 50 megawatts (MW) and larger.[6] Federal, state, and local agencies may be responsible depending on where the generation or transmission project is sited. Additionally, foreign authorities such as Mexican and Canadian agencies would be responsible for permitting international projects that schedule RPS-eligible electricity into the CAISO. The CPUC is responsible for environmental review and permitting of CPUC-jurisdictional retail seller transmission projects.[7] Additionally, the CEC adopts an Integrated Energy Policy Report (IEPR) every two years, which includes an extensive discussion and update on permitting for renewable generation facilities in California.

Furthermore, both the CPUC and CEC coordinate their review with federal, state, local, and regional agencies. The IOUs also assist in identifying future permitting barriers and work with developers to overcome project development issues.Additionally, both the CPUC and CEC work cooperatively on a number of interagency initiatives, such as the Desert Renewable Energy Conservation Plan (DRECP)[8] and most recently, the Renewable Energy Transmission Initiative 2.0 (RETI 2.0).[9] RETI 2.0 is intended to help achieve the state's current climate and policy goals, including a reduction in greenhouse gas emissions to 40 percent below 1990 levels by 2030 and further reduction to 80 percent below 1990 levels by 2050.

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[6] This includes geothermal, biomass, and solar thermal facilities in addition to natural gas facilities.

[7] The CEC power plant permitting process also includes transmission lines to the first point of interconnection with the grid, fuel supply lines, and water pipelines.

[8] The DRECP, when completed, is expected to further the objectives of California's RPS and provide binding, long-term endangered species permit assurances while streamlining and facilitating the review and approval of compatible renewable energy projects in the Mojave and Colorado deserts in California. More information on the DRECP can be found at: www.drecp.org/

[9] For more information on RETI 2.0, see the following: www.energy.ca.gov/reti/.

CPUC Transmission Permitting Update

The following section provides an update on significant transmission projects that the Commission has reviewed or is reviewing. It is important to note that while many RPS-eligible facilities may rely on these transmission lines, the lines will also support the transmission of non-RPS generation and provide necessary system reliability.

Coolwater-Lugo Transmission Project (CLTP)

Location	The project stretches from the Tehachapi Wind Resource Area in Kern County south through Los Angeles County and the Angeles National Forest and east to the existing Mira Loma Substation in Ontario, San Bernardino County, California.
Size of Line	220 kilovolt (kV) line / 115 kV line
Participating Transmission Owner (PTO)	SCE
Date of Application	August 28, 2013
Date of Decision	Application denied on May 26, 2015 (Decision 15-05-040)
Construction Completion Date	Not applicable due to denial of Application.
Delays Encountered	Application denied.
Status Update	The Coolwater-Lugo Transmission Project was intended to provide full-capacity deliverability to Abengoa-Mohave Solar at Coolwater Substation. The ISO determined that enough generation had retired that capacity on the existing lines was now available on a firm basis and the CLTP was not needed.

Tehachapi Renewable Transmission Project (TRTP)

Location	The project stretches from the Tehachapi Wind Resource Area in Kern County south through Los Angeles County and the Angeles National Forest and east to the existing Mira Loma Substation in Ontario, San Bernardino County, California.
Size of Line	220 kilovolt (kV) line / 500 kV line
Participating Transmission Owner (PTO)	SCE
Date of Application	6/29/2007

Tehachapi Renewable Transmission Project (Continued)

Date of Decision	12/17/2009 (TRTP approval), 7/11/13 (Chino Hills undergrounding)
Construction Completion Date	All segments are in service, with the exception of the underground portion through Chino Hills, which should be in service by late 2016.
Delays Encountered	The TRTP incurred delays of six to twelve months in the Chino Hills area due to a change in scope to underground and also due to a re-design of the horizontal boring construction.
Status Update	Installing the first 500 kV underground cable in the country is a unique challenge. SCE has stated their earlier schedule was overly optimistic.

Eldorado Ivanpah Transmission Project (EITP)

Location	The project straddles the California-Nevada border from the Ivanpah substation near Primm, California to the Eldorado substation near Boulder City, Nevada.
Size of Line	220 kV line
PTO	SCE
Date of Application	5/28/2009
Date of Decision	12/16/2010
Construction Completion Date	7/1/2013
Status Update	Project is complete.

Sunrise Powerlink Transmission Project

Location	The project stretches 117 miles along the southern boundaries of Imperial and San Diego counties.
Size of Line	230 kV line / 500 kV line
PTO	SDG&E
Date of Application	4/4/2006
Date of Decision	12/18/2008
Construction Completion Date	June 2012

Sunrise Powerlink Transmission Project (Continued)

Delays Encountered	SDG&E's original transmission line route was highly controversial because it crossed through 22 miles of Anza-Borrego Desert State Park. More than 100 alternatives routes were screened and 27 alternatives were seriously studied as part of the CEQA review. The CPUC approved a route that avoided going through the park.
Status Update	Project is complete.

Devers-Palo Verde No. 2 Transmission Project (DPV2) – California portion (Colorado River-Valley 500 kV line)

Location	Located in Riverside County along Interstate 10 between Colorado River Substation, Devers Substation and Valley Substation.
Size of Line	500 kV line
PTO	SCE
Date of Application	4/11/2005 (entire DPV2 project)
Date of Decision	1/25/2007 (entire DPV2 project); original decision modified on 11/20/2009 (Colorado River-Valley 500 kV line)
Construction Completion Date	9/26/2013
Delays Encountered	The original Commission Decision approved an alternative to the original project since the Morongo tribe did not approve of the transmission line crossing through their sovereign lands. Following the 2007 Commission Decision approving the project, the Arizona Corporation Commission denied SCE's request to construct the Arizona portion of the project.
Status Update	Project is complete.

Red Bluff Substation

Location	Located in the Desert Center area along Interstate 10 in Riverside County.
Size of Substation	500/220 kV substation
PTO	SCE
Date of Application	11/17/2010
Date of Decision	7/14/2011

Red Bluff Substation (Continued)

Construction Completion Date	6/6/2013
Delays Encountered	There were CEQA compliance issues with a National Environmental Protection Act (NEPA) document, requiring substantial revisions and technical analyses to the original NEPA document.
Status Update	Project is complete.

Sandlot Substation Project

Location	The substation is located on 10 acres of land within the boundary of the Abengoa Mojave Solar Project near Harper Lake in San Bernardino County.
Size of Project	220 kV substation
PTO	SCE
Date of Application	5/5/2011
Date of Decision	7/28/2011
Construction Completion Date	December 2014
Delays Encountered	Delays associated with the completion of the Abengoa Mojave Solar Project have occurred.
Status Update	Project is complete.

East County (ECO) Transmission Project

Location	The ECO Project located in southeastern San Diego County, approximately 70 miles east of downtown San Diego near the unincorporated communities of Jacumba and Boulevard. The ECO project includes developing the ECO substation and rebuilding the existing Boulevard Substation along with a new 14-mile transmission line connecting the two substations.
Size of Project	500/230/138 kV substation (ECO), 138/69/12 kV substation (Boulevard), and 138 kV line

East County (ECO) Transmission Project (Continued)

PTO	SDG&E
Date of Application	8/10/2009
Date of Decision	6/21/2012
Construction Completion Date	12/29/2014
Delays Encountered	Red flag fire warnings, species surveys, and water source issues.
Status Update	Project is complete.

Sycamore-Peñasquitos 230 kV Transmission Line Project

Location	The 16.7-mile line in San Diego County would connect the existing Sycamore Canyon and Peñasquitos Substations.
Size of Project	230 kV line
PTO	SDG&E
Date of Application	4/7/2014
Date of Decision	Estimated in 2016.
Construction Completion Date	2017 (tentative)
Delays Encountered	None.
Status Update	Draft EIR published on 9/17/2015.

Strategic Transmission Investment Plan in the CEC's 2015 Integrated Energy Policy Report[10]

In addition to being the primary state agency responsible for permitting renewable generation in California, the CEC is required by SB 1389[11] to adopt and transmit an IEPR to the Governor and Legislature every two years. The IEPR includes an extensive discussion on trends and issues concerning renewable energy and is used as a key data source in CPUC proceedings. The

[10] The CEC Draft 2015 Integrated Energy Policy Report can be found at: http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-01/TN206330_20151012T134153_2015_Draft_Integrated_Energy_Policy_Report.pdf.
[11] Bowen and Sher, Chapter 568, Statutes of 2002.

following section includes an overview of the permitting discussion in the IEPR's Strategic Transmission Investment Plan, which is required by SB 1565.[12]

The Strategic Transmission Investment Plan chapter of the Draft 2015 IEPR provides a status update for transmission projects associated with the 2020 RPS requirement and also discusses other transmission issues such as efforts to integrate environmental information into renewable energy generation and transmission planning. The chapter also describes intrastate and interstate transmission planning and projects that can help California meet its renewable generation goals, and opportunities for easing future potential transmission build-out. The Draft 2015 IEPR identified 17 transmission projects that were approved for the integration of renewable resources. The California Independent System Operator (CAISO) has noted that there is no further need for any new major transmission projects for 2020 RPS purposes at this time.[13] Fifteen of these projects are within the CAISO's control area, and the CEC is assisting interested parties in tracking these projects by updating and posting the projects' status annually on its website.[14,15]

Overarching Permitting Issues Associated with Transmission Projects for Renewable Projects

Currently, we are not experiencing many permitting issues leading to delays in completing transmission projects for RPS-eligible facilities. For transmission projects requiring state and federal approvals, the added complexity of completing both Environmental Impact Reports and Environmental Impact Statements could result in some additional time.

CEC Generation Permitting Update

The following section provides an update on significant CEC-jurisdictional renewable generation projects, as well as all renewable generation projects in California (including those outside the CEC's jurisdiction) that have received environmental permits and may become operational.

CEC December 2015 Renewable Energy Tracking Summary[16]

Approximately 680 MW of new renewable capacity achieved commercial operation in the first eleven months of 2015. Approximately 680 MW of new renewable capacity achieved commercial operation in the first eleven months of 2015. As of October 31, 2015, approximately 21,700 MW of RPS-eligible capacity was operating in California.

In addition to the 21,700 MW of operational RPS-eligible capacity, an incremental 11,800 MW of renewable energy capacity has received permits from federal, state, and/or local agencies, and

[12] Bowen, Chapter 692, Statutes of 2004.

[13] *See* page 9 of the California Independent System Operator 2014-2015 Transmission Plan available at: www.caiso.com/Documents/Board-Approved2014-2015TransmissionPlan.pdf

[14] CEC Draft 2015 Integrated Energy Policy Report, page 102.

[15] The CEC's RPS tracking documents can be found at: www.energy.ca.gov/renewables/tracking_progress/#renewable.

[16] For details on the CEC's latest renewable energy progress tracking *See* the CEC's December 2015 Renewable Energy Tracking Progress Overview which is available at: www.energy.ca.gov/renewables/tracking_progress/documents/renewable.pdf.

could achieve commercial operation in the future. Of the 11,800 MW of potential renewable energy capacity, approximately 2,000 MW of potential renewable energy capacity is under a power purchase agreement with one of California's load serving entities. Lastly, about half (1,080 MW) of the 2,000 MW of potential renewable energy capacity with contracts is expected to achieve commercial operation in 2016, almost all from solar facilities.

The CEC has made substantial progress on renewable generation facility siting. Tables 3 and 4 provide status data and details on recent renewable generation siting cases that are under CEC jurisdiction.

Table 3. **CEC-Jurisdictional Renewable Energy Facility Status for Approved Projects Operational, Under Construction, or Under Pre-construction**[17]

Projects On-Line	**Type**	**Status**	**Capacity (MW)**	**County**
Genesis Solar Energy Project – NextEra Energy	Solar Thermal	Operational	250	Riverside
Ivanpah Solar – BrightSource, NRG Energy, Google	Solar Thermal	Operational	370	San Bernardino
Abengoa Mojave Solar Project – Mojave Solar LLC	Solar Thermal	Operational	250	San Bernardino
		Subtotal:	**870**	
Under Construction	**Type**	**Status**	**Capacity (MW)**	**County**
Blythe Solar – NextEra Blythe Energy Center LLC	Solar PV	Under Construction	485	Riverside
		Subtotal:	**485**	

Source: California Energy Commission, [http://energy.ca.gov/sitingcases/all_projects.html].
Updated November 16, 2015. Capacity represents net nameplate capacity and excludes onsite and parasitic loads.

[17] CEC December 2015 Renewable Energy Tracking Summary.

Table 4. **CEC-Jurisdictional Renewable Energy Facility Status for Projects Not Under Construction**

Not Under Construction	Type	Status	Capacity (MW)	County
Black Rock 1, 2, and 3 Geothermal Power Project (formerly Salton Sea Geothermal) - Cal Energy	Geothermal	Approved, On Hold	159	Imperial
Victorville Hybrid Gas-Solar – City of Victorville (513 MW Gas + 50 MW Solar)	Solar Thermal/ Natural Gas	Approved, On Hold	50	San Bernardino
Palmdale Hybrid Gas-Solar – Summit Power Group LLC (formerly City of Palmdale) (520 MW Gas + 50 MW Solar)	Solar Thermal/ Natural Gas	AFC Approved Amendment Under Review to Eliminate Solar	[50]	Los Angeles
Rice Solar Energy Project - Rice Solar Energy LLC / SolarReserve LLC	Solar Thermal	Approved, On Hold	150	Riverside
Palen Solar Electric Generating System – Palen Solar Holdings, LLC	Solar Thermal	Approved Amendment Petition Expected December 22, 2015 to switch to molten salt solar trough technology	500	Riverside
		Subtotal:	**859**	
		Total for All Projects Table 3 and Table 4	**2,214**	

Source: Energy Commission
Updated November 16, 2015. Capacity represents net nameplate capacity and excludes onsite and parasitic loads.

Table 5 shows all renewable energy generation projects in California, including those outside the CEC's jurisdiction, which have received environmental permits and may become operational. The information includes projects that are in pre-construction or under construction. Table 5 shows the number of projects and capacity by county and by renewable technology type.

Table 5. **Renewable Projects that Have Received Environmental Permits and are Expected to Come On-Line After 2015**

	Biomass/ Landfill Gas		Solar PV		Solar Thermal		Geothermal		Wind		Small Hydro		Total	
County	**Count**	**MW**	**Count**	**MW**	**Count**	**MW**	**Count**	**MW**	**Count**	**MW**	**Count**	**MW**	**Count**	**MW**
Alameda			2	12					2	110			4	122
Colusa	1	30	1	20									2	50
Fresno			26	846									26	846
Glenn			2	40									2	40
Imperial			14	1,302			2	209					18	1,511
Inyo			1	4									1	4
Kern			30	1,701					13	1,526			43	3,227
Kings			12	538									12	538
Lassen			1	5									1	5
Los Angeles			23	386							1	4	24	390
Madera			2	40									2	40
Marin			1	2									1	2
Merced			4	315									4	315
Mono							1	33					1	33
Monterey			2	282									2	282
Napa			1	7									1	7
Orange	1	24	1	4									2	27
Placer	1	2											1	2
Riverside			12	1,974	1	500							13	2,474
Sacramento			1	11									1	11
San Benito			1	247									1	247
San Bernardino			18	568	1	50							19	618
San Diego			2	122					1	200			3	322
San Joaquin			2	22									2	22
Santa Barbara			1	40									1	40
Santa Clara	1	3	9	21									10	24
Solano	1	8											1	8
Sonoma							3	113					3	113
Stanislaus			3	270									3	270
Tulare	1	2	5	174									6	176
Yolo			1	2					1	2			2	3
Yuba			1	1									1	1
Total	**6**	**68**	**179**	**8,951**	**2**	**550**	**6**	**355**	**17**	**1,837**	**1**	**4**	**211**	**11,800**

Source: California Energy Commission staff. Totals may not sum due to rounding. Updated in July 2015. Capacity represents nameplate capacity. Solar PV capacity is AC.

Due to frequent changes in project circumstances (e.g., loss of developer financing, delays in obtaining power purchase agreements, and inability to meet other agencies' permitting requirements), project status data are fluid. Therefore, the renewable energy siting information presented in Tables 3 through 6 reflects a snapshot in time relative to the status of projects in the CEC siting database.[18]

Permitting Issues Identified in the IOU's 2015 RPS Procurement Plans

In August 2015, each IOU filed their annual RPS Plan describing the actions that they would take to meet their RPS procurement requirements. Each IOU's RPS Plan included a section on the permitting and siting of renewable generation projects. The following section summarizes sections from each IOU's RPS Plan that addressed permitting issues as they are related to each IOU achieving its RPS compliance requirement.

PG&E[19]

PG&E states that it continues to participate in the planning process with various stakeholders to find solutions for environmental siting and permitting issues faced by renewable energy development. Common permitting and siting hurdles that still can occur for renewables projects include challenges related to farmland designation and Williamson Act contracts, tribal and cultural resources areas, protected species, and county-imposed moratoriums. These hurdles may impact development schedules for projects.

SCE[20]

SCE states that the lengthy process of siting, permitting, and building new transmission continues to be a real and complicated impediment to bringing new renewable resources online and in a timely manner. Specifically, SCE lists environmental concerns, legal challenges, and public opposition as factors that impact the timeline for bringing renewable generation and transmission projects on-line.

SDG&E[21]

Uncertainty surrounding the timely issuance of key permits associated with lead agency review continues to create risks for projects under development. The permitting timeline can vary greatly based on a multitude of factors including project location, environmental issues, lead/other agency resources, and public participation. This uncertainty may lead to scheduling challenges and corresponding problems with project elements such as site control, financing, permitting, engineering, procurement including supplier and construction (EPC) contracts.

[18] CEC December 2015 Renewable Energy Tracking Summary, Page 14.
[19] PG&E draft RPS Procurement Plan, Pages 22-23.
[20] SCE draft RPS Procurement Plan, Pages 33.
[21] SDG&E draft RPS Procurement Plan, Page 39.

COST LIMITATION

> Section 913.6(c)
>
> *[This Report shall contain] The projected ability of each electrical corporation to meet the renewables portfolio standard procurement requirements under the cost limitations in subdivision (d) of Section 399.15 and any recommendations for revisions of those cost limitations.*

Section 399.15(c)-(d) orders the Commission to establish a limitation for each electrical corporation on the procurement expenditures for all eligible renewable energy resources to comply with California's RPS. The Commission is in the process of implementing this code section. In July 2013, the Administrative Law Judge issued a Ruling seeking comments on Energy Division's staff proposal for a methodology to implement a procurement expenditure limitation and Commission staff held a workshop on this topic in November 2013. Additionally, a revised staff proposal was issued via a Ruling in February 2014. More recently, SB 350 (De León, 2015) amended Section 399.15(c), along with several other RPS portions of the RPS statute. The Commission will begin implementing SB 350, including procurement expenditure limitation, in 2016.

Due to the Commission's ongoing implementation of Section 399.15(c)-(d), it is not possible to completely fulfill the reporting requirement of Section 399.15(c) at this time. Having said that, RPS prices have experienced a continual decline over the life of the program and retail sellers should be able to meet the cost limitations of Pub. Util. Section 399.15(d), for the 33% RPS, upon implementation.

From 2003 to 2014 the average time of delivery (TOD)-adjusted price of contracts approved by the CPUC has decreased from 9.2 cents to 7.4 cents/kWh (real dollars).22 The decrease in RPS contract prices indicates that the renewable market in California is robust and competitive and has matured since the start of the RPS program.

RPS contract prices approved by the CPUC in 2014 are much lower than the nominal prices of contracts approved in 2013 and 2012 (7.4 in 2014 and 2015 versus 8.1 cents in 2013 and 9.6 cents in 2012). The lower contract prices are a result of projects selected from RPS solicitations in years 2011-2013, which reflect declining contract prices for renewable resources, on average. Given the declining contract prices and the IOUs expected ability to meet their RPS requirements, the Commission's implementation of procurement expenditure limitation will focus on properly valuing needed attributes such as flexibility and/or storage, and how procurement expenditure limitation can be used to incentivize California's utilities to purchase the right balance of RPS-eligible resources to meet the demands of the future market.

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[22] The CPUC used the Handy- Whitman Index of Public Utility Construction Costs – Other Production Plant - Pacific region to calculate the real dollar amounts for year 2014.

RPS BARRIERS AND RECOMMENDATIONS

> Section 913.6(d)
>
> *[This Report shall contain] Any barriers to, and policy recommendations for, achieving the renewables portfolio standard pursuant to this article.*

In their 2015 RPS Procurement Plans, the IOUs included a section that discussed potential barriers to achieving future RPS compliance. The following section includes an overview of the different barriers listed by the IOUs in their RPS plans. Furthermore, this section includes a discussion of how the IOUs and other associated agencies plan to overcome the barriers that they have identified.

This report focuses on the barriers surrounding RPS procurement, RPS resources, and transmission in the context of the 33% RPS program. Additional information about the challenges and solutions the Commission anticipates in implementing a 50% RPS program can be found in Energy Division's staff white paper, "Beyond 33% Renewables: Grid Integration Policy for a Low-Carbon Future."[23]

Financing

The IOUs are hopeful that the current trends in renewable project financing continue. Those trends will help renewable developers overcome financial barriers and enable additional renewable energy supply at reduced procurement costs for customers. Since the phase-out of the 1603 Treasury Cash Grant at the end of 2012, investors with a tax appetite as tax equity investors have been crucial to successfully financing renewable energy projects.

On December 18, 2015, the solar ITC and wind tax PTC were extended by the federal government.[24] Specifically, the 30 percent ITC for solar is be extended for another three years. It will then decline incrementally through 2021 to 10 percent starting in 2022. Also, the PTC for wind is extended through 2016. Wind projects that begin construction in 2017 will see a 20 percent reduction in the incentive. The PTC will then drop 20 percent each year through 2020.

The five-year and seven-year Modified Accelerated Cost Recovery System (MACRS) allows for accelerated tax depreciation deductions to renewable tangible property. These tax incentives and the MACRS depreciation deductions enable businesses to reduce their tax liability and accelerate the rate of return on renewable investments. They also provide a workable framework for projects to negotiate financing. As a result, tax incentives have spurred significant investment in renewable energy and generally amount to between 35 and 60 cents per dollar (¢/$) of capital cost.

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[23] The Beyond 33% Renewables: Grid Integration Policy for a Low-Carbon Future paper can be found at: www.cpuc.ca.gov/NR/rdonlyres/8F428686-2FB5-4F3D-85B3-0475694E4718/0/Beyond33PercentRenewables_GridIntegrationPolicy_Final.pdf

[24] H.R.2029 - Consolidated Appropriations Act, 2016: www.congress.gov/bill/114th-congress/house-bill/2029

Interconnection and Transmission

The IOUs have commented that the development and funding of additional transmission infrastructure continues to be a significant impediment to California reaching its renewable energy requirements. Over the past few years, the CAISO and the IOUs have seen a significant increase in the number of generators requesting to interconnect into the grid. The growth in these requests has, in turn, led to an overcrowded interconnection queue at the CAISO and extended estimated project development timelines. Projects that experience interconnection delays face a significant barrier to receiving financing when pressed with the requirement to come online within tight contractual milestone dates. The growth in interconnection requests has also made it difficult to estimate reliable interconnection study results that identify necessary transmission upgrades and their associated costs and timing.

To improve the management of the transmission planning and interconnection processes, the CAISO has adopted the Generator Interconnection and Deliverability Allocation Procedures (GIDAP) after its implementation of the TPP-GIP initiative. Under GIDAP, the largest and most important ratepayer-funded transmission upgrades for generator interconnection are no longer principally driven by the large amounts of potential generation entering the interconnection process, but rather are driven by the more comprehensive and inter-linked central resource and transmission planning processes. Overall, GIDAP and additional ongoing interconnection reforms provide greater flexibility and cost transparency for generation projects that participate in the interconnection process, and also incentivize timely exit of non-viable generation projects from the interconnection queue, providing better predictability of costs and timing for the remaining projects.

Additionally, the California Energy Commission, California Public Utilities Commission, and the California Independent System Operator have initiated RETI 2.0 to facilitate electric transmission coordination and planning. RETI 2.0 is an open, transparent, and science-based process that will explore the renewable generation resources in California and throughout the West, consider critical land use and environmental constraints, and identify potential transmission opportunities that could access and integrate renewable energy with the most environmental, economic, and community benefits.

At the intersection of transmission-level and distribution-level interconnections, is the Distributed Generation Deliverability (DGD) process. In 2013, the CAISO implemented the first annual cycle, and the second and third cycles were successfully completed in 2014 and 2015, respectively. Under the DGD Program, the CAISO conducts an annual study to identify MW amounts of available deliverability at transmission nodes on the CAISO-controlled grid. Based on the deliverability assessment results, distributed generation facilities that are located or seeking interconnection at nodes with identified available deliverability may apply to the appropriate Participating Transmission Owner (PTO) to receive an assignment of deliverability for Resource Adequacy (RA) counting purposes.

At the distribution level, the CPUC issued a Decision in September 2012 approving the first set of reforms to Electric Rule 21 (Rule 21) to establish a process to accommodate the interconnection of exporting generating facilities at the distribution level. Rule 21 is a set of rules governing how distributed energy technologies may interconnect with the electric distribution systems of the state's IOUs.

In 2015, the CPUC oversaw significant progress in improving Rule 21, the CPUC jurisdictional tariff governing the application and study process for distributed energy resource interconnection, as well as development of advanced inverter functionality. Specifically, the CPUC initiated an active stakeholder process within the Interconnection Rulemaking (R.11-09-011)[25] focused on two primary goals: 1) enhancing the predictability and certainty of interconnection upgrade costs and 2) standardizing and streamlining Rule 21 interconnection for non-exporting, behind-the-meter energy-storage devices.

In the fall of 2015, the CPUC's Energy Division facilitated a series of stakeholder workshops that resulted in the November 2015 filing of joint-party proposals that are now under Commission review with consideration of the following:

1. Expansion of the Rule 21 Pre-Application Report to provide prospective applicants with higher resolution data on site and system components than the currently available report;
2. Publication of a distribution Unit Cost Guide to provide applicants with insights into illustrative component costs for typical system upgrades that are triggered by interconnection applications;
3. Improvements in the transparency surrounding how information on energy storage charging behavior is collected and studied in the Rule 21 application process;
4. Creation of an expedited interconnection application and a study process for certified, standardized non-exporting storage configurations;
5. Revisions to Rule 21 to deem the use of certified converter technology that physically prevents back feed to the grid to be sufficient to obviate the need for an interconnection study; and
6. Creation of an additional inadvertent export option that utilizes advanced inverter functionality to maintain acceptable levels of safety and reliability.

According to the joint party proponents, these pending proposals would work to enhance the distributed energy resource interconnection process, which would make it easier for customers to interconnect those energy technologies that grid modernization efforts are intended to accommodate. Commission decision on these issues is expected the first quarter of 2016.

Permitting

The IOUs have identified the permitting process for renewable generation as a barrier to meeting their RPS compliance requirements. Permitting delays can occur at the county, state, and/or federal level, and are typically the result of environmental concerns, legal challenges, and/or public opposition. Renewable developers, particularly those of wind and solar projects, face challenges related to farmland designation and Williamson Act contracts, tribal and cultural resources areas, and protected species.

The uncertainty surrounding the availability and timely issuance of necessary permits creates downstream development risks for renewable project development including: scheduling challenges and corresponding problems with site control, financing, permitting, engineering,

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[25] R.11-09-011 - Establishing Distribution-Level Interconnection Rules for Certain Generators and Storage

procurement and construction (EPC) contracts and supplier contracts. Section 913.6(b) of this report, at p. 9, discusses steps being taken by the CPUC, CEC, and IOUs to address these permitting barriers.

Developer Performance Issues

California's renewable energy goals are dependent on renewable developers meeting contractual obligations, timely completion of construction milestones, and achieving commercial operation. Hurdles encountered during the project development process require developers to alter their milestone schedules, which can result in delays and contract terminations. For example, several renewable projects have been terminated due to project milestone issues such as: poor site selection, permitting delays, and the inability to complete the CAISO interconnection process in a timely and cost-effective manner.

To proactively address developer performance issues, the IOUs maintain constant communications with project developers, discuss options and the status of project development, and provide guidance and direction as appropriate. In response to lessons learned from previous projects, the IOUs have made several modifications to their solicitation materials. For example, some IOUs have created an option to have the IOU act as scheduling coordinator, allow for delivery points at the point of interconnection with the transmission provider's electric grid, and tailored certain terms and conditions to address market changes in equipment availability and supply.[26] Additionally, the IOUs have collaborated with stakeholders in local communities to promote local support for renewable projects through renewable education programs.

Curtailment

As more renewable generation achieves commercial operation, congestion at the transmission and distribution levels is increasing. As a result of over generation in congested areas of the grid, the market price for energy is driven down to the point that the market price is negative. Excessively low and negative power prices are intended to signal to generators to lower production or curtail when there is more generation than available transmission capacity (or load) in a particular area. Renewable generation may be economically bid into the market to avoid the negative price. However, some of the older renewable contracts are structured in a way so that generators are insulated from these price signals due to their lack of economic curtailment terms. When price signals are not enough to entice generators to decrease their output to alleviate congestion on the grid, the CAISO may resort to curtailing generators for system reliability purposes.

Increasing Proportion of Intermittent Resources in RPS Portfolios

Over the last several years, a large number of solar and wind projects have achieved commercial operation. The influx of intermittent renewable generation makes an IOU's forecasting of its RPS need more complex. Actual production from wind generators varies significantly from hour-to-hour, month-to-month, and year-to-year, thereby potentially exposing IOUs to large fluctuations in renewable energy deliveries. Solar production also varies over time depending on weather conditions and project performance, among other factors.

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[26] SCE 2015 Draft RPS Procurement Plan, Page 35-36.

Given the number of intermittent resources expected to achieve commercial operation in the coming years, the IOUs are preparing to successfully integrate new wind and solar resources. For example, generation forecasting accuracy is being improved by collecting actual generation data from new wind and solar resources and analyzing forecasted output versus actual production after-the-fact.

To address the increasing proportion of intermittent resources in the utilities RPS portfolios, Energy Division staff has studied the reliability impact of wind and solar facilities to adopt effective load carrying capability factors. Energy Division staff has issued several reports describing the proposed methods and data inputs for the model that it using for these studies, as well as the model's outputs. Currently, Energy Division staff is in the process of updating the inputs and scenarios using the Transmission Expansion Planning Policy Committee (TEPPC) 2024 Common Case (v1.5)[27] and those updates will yield more exact and precise identification of generation and load forecasts for areas external to California. Energy Division staff will continue to model the California's electric market to further validate results. As updates are made the resulting information is expected to improve the economic dispatch of thermal generators and to calibrate import and export flows between study areas.

[27] The Transmission Expansion Planning Policy Committee (TEPPC) was established by the WECC Board of Directors on April 19, 2006 as a Board committee. The purpose of TEPPC is to conduct and facilitate economic transmission planning in the Western Interconnection.
The TEPPC Common Case is a specific production simulation model developed by WECC staff that uses inputs from westwide TEPPC stakeholders including utilities, independent transmission and generation developers (and marketers), state and other energy agencies, and various NGO/stakeholder interests. The TEPPC Common Case model projects Western Interconnection loads 10-years forward, and transmission needs based on current plans and forecasts.

APPENDIX A

Text of Section 913.6 of the Public Utilities Code

913.6.
The commission, in consultation with the Energy Commission, shall report to the Legislature by January 1 of every even-numbered year on all of the following:

(a) The progress and status of procurement activities by each retail seller pursuant to the California Renewables Portfolio Standard Program (Article 16 (commencing with Section 399.11) of Chapter 2.3).

(b) The status of permitting and siting eligible renewable energy resources and transmission facilities necessary to supply electricity generated to load, including the time taken to permit each eligible renewable energy resource and transmission line or upgrade, explanations of failures to meet permitting milestones, and recommendations for improvements to expedite permitting and siting processes.

(c) The projected ability of each electrical corporation to meet the renewables portfolio standard procurement requirements under the cost limitations in subdivision (d) of Section 399.15 and any recommendations for revisions of those cost limitations.

(d) Any barriers to, and policy recommendations for, achieving the renewables portfolio standard pursuant to the California Renewables Portfolio Standard Program (Article 16 (commencing with Section 399.11) of Chapter 2.3).