2019

Padilla Report

Costs and Cost Savings for the RPS Program (Public Utilities Code §913.3)

May 1, 2019

CALIFORNIA
PUBLIC
UTILITIES
COMMISSION

About this Report

The purpose of this annual Report is to comply with Public Utilities Code § 913.3. Each May 1, the California Public Utilities Commission is required to report to the Legislature the aggregated costs and cost savings of renewable energy expenditures and contracts for the previous year.

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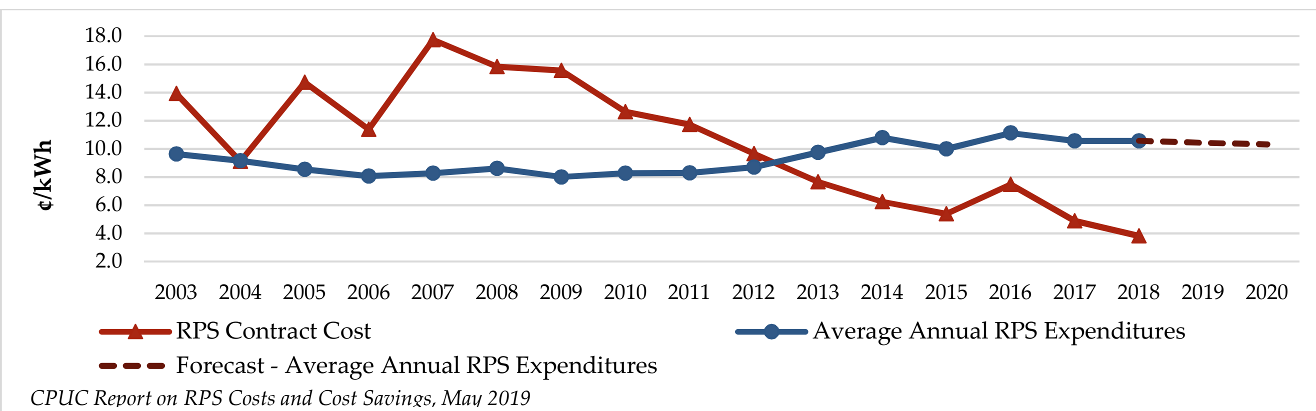
EXECUTIVE SUMMARY

In compliance with Public Utilities Code § 913.3,[1] this report describes 2018 Renewables Portfolio Standard (RPS) program procurement cost data. In 2018, investor-owned utilities either met or exceeded their RPS procurement obligations while also increasing their procurement of renewables.[2] This increase in procurement of renewable resources is consistent with legislation, which has escalated RPS procurement goals.

The key conclusions from this report include the following:

- The large investor-owned utilities' (IOUs) total annual RPS procurement expenditures increased from $5.3 billion in 2017 to $5.6 billion in 2018 while total renewables generation increased 52,469 GWh to 52,936 GWh, or 36% to 40% of total generation procurement, from 2017 to 2018.[3]
- For the small and multi-jurisdictional investor-owned utilities (SMJUs) total annual RPS procurement expenditures decreased from $14.2 million in 2017 to $10.7 million in 2018 while total renewables generation decreased from 367 GWh to 334 GWh, or 27% to 26% of total generation procurement, from 2017 to 2018.
- For the large IOUs, 37.8% of total generation was from renewable resources and expenditures on renewable generation was 41.8% of the IOUs' total generation costs. This shows that RPS expenditures as a percent of total generation costs is about equal to the percent of total generation from renewable resources and that renewables are on par with non-renewables.
- The large IOUs' average procurement expenditure for all RPS contracts online increased slightly from 10.1 cents per kilowatt-hour (¢/kWh) in 2017 to 10.6 ¢/kWh in 2018.
- RPS expenditures are anticipated to decrease slightly and the cost of new RPS projects are expected to decline over time.

Figure 1: RPS Program Expenditures and Contract Costs from 2003-2020[4]
(Real Dollars)



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[1] The full text of California Public Utilities Code (*hereinafter* Pub. Util. Code) § 913.3 can be found in Appendix D.

[2] This report also addresses 2018 contract prices for Community Choice Aggregators (CCAs) and Electric Service Providers (ESPs) in 2018, but it does not address their expenditures or RPS compliance. This report does not address Publicly Owned Utilities (POUs).

[3] Large IOU procurement expenditures include payments for curtailment volumes which generally increases the unit price of energy reported. See California ISO's Managing Oversupply page for more information on curtailment: http://www.caiso.com/informed/Pages/ManagingOversupply.aspx.

[4] Values adjusted for inflation using the U.S. Bureau of Labor Statistics' Producer Price Index (PPI) for the Electric Power Generation, Transmission, and Distribution Industry. This PPI was chosen as an effective method for capturing price movement specific to a given industry prior to retail level price changes.

BACKGROUND

Senate Bill (SB) 836 (Padilla, 2011) requires the California Public Utilities Commission (Commission or CPUC) to report on the Renewables Portfolio Standard (RPS) program to the Legislature regarding "the costs of all electricity procurement contracts for eligible renewable energy resources, including unbundled renewable energy credits, and all costs for utility-owned generation approved by the Commission."[5]

The California RPS program was established in 2002 by Senate Bill (SB) 1078 (Sher, 2002) with the initial requirement that 20% of electricity retail sales must be served by renewable resources by 2017. The program was accelerated in 2006 under SB 107 (Simitian, 2006), which required that the 20% mandate be met by 2010. In April 2011, SB 2 (1X) (Simitian, 2011) codified a 33% RPS requirement to be achieved by 2020. In 2015, SB 350 (de León, 2015) mandated a 50% RPS by December 31, 2030. On September 10, 2018, SB 100 (de León, 2018) was signed into law, which again increased the RPS to 60% by December 31, 2030, with interim targets of 44% by December 31, 2024, and 52% by December 31, 2027 and requires all the state's electricity to come from carbon-free resources by 2045.[6]

The 2018 RPS procurement cost figures in this report were compiled from the large IOUs—Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E)—as well as the SMJUs—Liberty Utilities (Liberty), Bear Valley Electric Service (BVES), and PacifiCorp. The annual procurement costs for generation in this report may not correspond precisely with the utilities' RPS compliance cost for the same year. Because the Renewable Energy Credits (RECs) associated with generation can be applied in later years for RPS program compliance purposes, the cost of procuring renewable energy might occur in one year and the RECs associated with generation may be applied in a later year.[7] Additionally, as a result of the 2018 Power Charge Indifference Adjustment (PCIA) decision, departing load customers remain responsible for a portion of RPS expenditures associated with contracts executed prior to the time they end service from an IOU.[8] Departing load customers refers to those ratepayers who were formerly served by the IOUs then shifted to receiving service from Community Choice Aggregators (CCAs) or Electric Service Providers (ESPs).

[5] Pub. Util. Code § 913.3(a). SB 697 (Hertzberg, 2015) changed the numbering of the Pub. Util. Code sections, and specifically changed § 910 to Pub. Util. Code § 913.3. None of the original reporting requirements that were required under Pub. Util. § 910 were modified by SB 697. SB 1222 (Hertzberg, 2016) modified the reporting date for this report among other minor changes.
[6] See the CPUC's RPS website for more information about RPS program requirements and legislative history: http://www.cpuc.ca.gov/renewables/.
[7] See Commission Decision (D.)12-06-038; D.17-06-026.
[8] See D.18-10-019; Pub. Util. Code § 366.2(a)(4).

RENEWABLES PROGRAM COSTS

This section addresses the costs associated with renewable resource procurement in 2018, consistent with the requirements of § 913.3(a)(1)-(2) and (b).

Section 913.3(a)(1)
For power purchase contracts, the commission shall release costs in an aggregated form categorized according to the year the procurement transaction was approved by the commission, the eligible renewable energy resource type, including bundled renewable energy credits, the average executed contract price, and average actual recorded costs for each kilowatt-hour of production. Within each renewable energy resource type, the commission shall provide aggregated costs for different project size thresholds.

Section 913.3(a)(2)
For each utility-owned renewable generation project, the commission shall release the costs forecast by the electrical corporation at the time of initial approval and the actual recorded costs for each kilowatt-hour of production during the preceding calendar year.

Section 913.3(b)
The commission shall report all electrical corporation revenue requirement increases associated with meeting the renewables portfolio standard, as defined in § 399.12, including direct procurement costs for eligible renewable energy resources and renewable energy credits.

The 2018 costs and cost savings discussed in this section for California's large IOUs and SMJUs include:

1. RPS Procurement Expenditures
2. RPS Aggregated Contract Prices
3. Comparison of RPS Procurement Expenditures with IOU Revenue Requirements

I. RPS Procurement Expenditures

Large Investor-Owned Utility Procurement Expenditures for 2018[9]

The CPUC compiled detailed information regarding RPS generation procured by the large IOUs in 2018. This summarized data can be found in Appendix B of this report. The data is expressed as weighted averages for RPS procurement expenditures in cents per kilowatt-hour (¢/kWh) categorized by IOU, technology, and size.[10]

Table B-1 provides all procurement expenditure information for every large IOU RPS eligible contract,[11] including utility-owned generation (UOG) projects.[12] Table B-1 includes the actual price for production in 2018 of utility-owned generation, which include small hydroelectric and solar photovoltaic facilities.

Based on the compiled 2018 data, the weighted average RPS procurement expenditure was approximately 10.6 ¢/kWh across all RPS contracts, including REC-only contracts. This 2018 average is slightly higher than the 10.1 ¢/kWh average in 2017.

Weighted Average Expenditures

Figure 2 below illustrates the weighted average RPS procurement expenditure for bundled renewable energy in ¢/kWh for each of the large IOUs from 2003 through 2018. The changes in weighted average expenditures over time for each large IOU are similar, and the key factors driving the cost differences between the large IOUs are the resource mixes and contract vintages.

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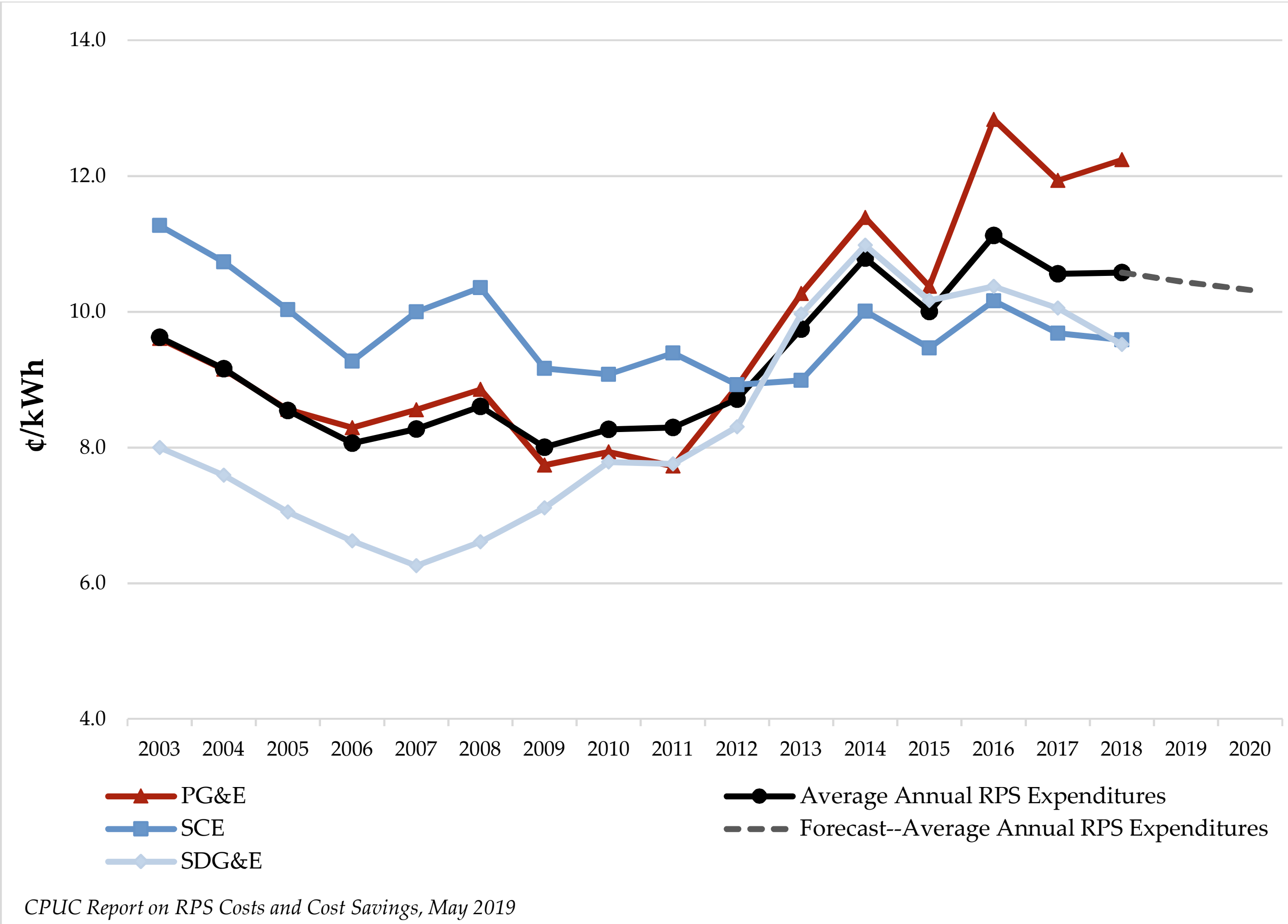
9 "Procurement Expenditures for 2018" includes costs for all procurement from online RPS eligible facilities that generated electricity in 2018. Additionally, "Procurement Expenditures for 2018" does not include costs from contracts that were approved by the CPUC in 2018 unless the contracted deliveries also began in 2018.

10 The cost of RPS procurement expenditures are weighted based on actual quantities of energy delivered.

11 Table B-1 can be found in the attached Appendix B. Pursuant to the confidentiality rules in Public Utilities Code § 913.3(d) and D.06-06-066, some of the costs in Appendix B have been redacted.

12 At the inception of the three IOUs' solar photovoltaic programs (SPVP-UOG), the CPUC approved an average levelized cost of energy (LCOE) for each IOU. For PG&E's utility-owned generation (UOG) projects, the CPUC approved an average LCOE of $0.25/kWh. (D.10-04-052 at 36.) For SCE's UOG projects, the CPUC approved an average LCOE of $0.26/kWh. (D.09-06-049 at 31.) For SDG&E's UOG projects, the CPUC approved an average LCOE of $0.24/kWh. (D.10-09-016 at 32.) See Appendix B for actual recorded costs. The UOG small hydroelectric facilities used for 2018 RPS generation began commercial operation primarily between 1900 and 1960.

Figure 2: Weighted Average RPS Procurement Expenditures of Bundled Renewable Energy from 2003-2020
(Real Dollars)



As shown in Figure 2 above, initial average annual RPS expenditures were lower than current expenditures for the program. At the beginning of the RPS program in 2003, the large IOUs' RPS resources consisted primarily of heavily depreciated small hydroelectric facilities. Starting in 2010, new resources from contracts signed around 2007 finished construction, began coming online, and increased average expenditures. Historic contract price trends can be seen in Figure 3, which shows that executed contract prices peaked in 2007 and have been falling for RPS-eligible resources. Because a large volume of contracts were signed between 2007 and 2010 and it takes several years from when a contract is executed to when it delivers energy, there will be a lag between when the lower cost contracts were executed and when expenditures will decline in real dollars.

To approximate the impact of decreasing contract prices on future expenditures, Figure 2 includes a forecast of RPS expenditures. The forecast in Figure 2 is based on future years' contract costs and generation volumes reported by the IOUs in the RPS Executed Projects Database.[13] On average, total forecasted RPS procurement expenditures decline 2.5% in 2019 and 2020. All graphs in this report are adjusted for inflation using the U.S. Bureau of Labor Statistics' Producer Price Index (PPI) for the Electric Power Generation, Transmission, and Distribution Industry.

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[13] This forecast represents a change in methodology from the 2018 Padilla report where the forecasted decline in average annual RPS expenditures was 2% per year between 2018 and 2020.

Total Expenditures

The changes in total expenditures over time corresponds with the large IOUs' increase in renewable procurement. The large IOUs' total combined direct RPS procurement expenditures increased from $5.3 billion in 2017 to $5.6 billion in 2018. This increase correlates to the large IOUs' renewable procurement increasing from 52,469 GWh to 52,936 GWh, or 36% to 40% of total generation procurement, from 2017 to 2018.[14]

Small and Multi-Jurisdictional Investor-Owned Utility Procurement Expenditures for 2018

In 2018, Liberty, PacifiCorp, and BVES spent approximately $10.7 million on RPS procurement. The SMJUs' RPS resources include biomass, geothermal, hydroelectric, solar photovoltaic, and wind.

Weighted Average Expenditures

In 2018, the weighted average RPS procurement expenditure for all Liberty contracts was 3.6 ¢/kWh, 3.4 ¢/kWh for PacifiCorp, and 0.9 ¢/kWh for BVES.[15]

Total Expenditures

For 2018, Liberty, PacifiCorp, and BVES had a total combined RPS procurement expenditure of $10.7 million in 2018 compared to $14.2 million in 2017. The SMJUs' total expenditures decreased in 2018, because Liberty started receiving roughly 86% of its RPS energy from a lower cost source. The SMJUs' total renewable procurement decreased by approximately 33 GWh from 2017 to 2018 and their average RPS procurement percentage decreased from 27% to 26%.[16]

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[14] CPUC, "California's Renewables Portfolio Standard Annual Report", at 5 (November 2018): http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy_-_Electricity_and_Natural_Gas/Renewables%20Portfolio%20Standard%20Annual%20Report%202018.pdf.

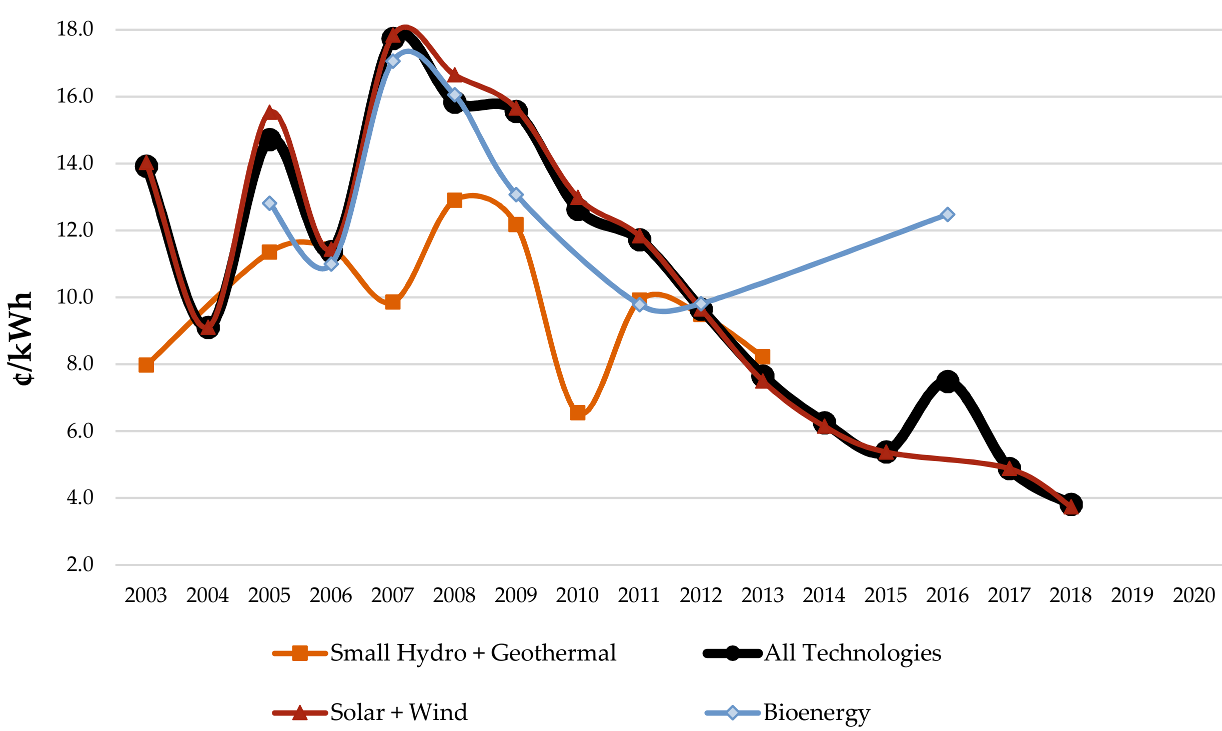
[15] BVES's 2018 procurement expenditure data includes strictly REC-only contracts; therefore, it is not comparable to the other utilities' 2018 expenditures as they procured significant quantities of contracts that include the cost of acquiring RECs, capacity, and energy.

[16] *Supra* note 14 at 6.

II. RPS Aggregated Contract Prices

The CPUC examined prices for contracts executed in 2018 by all Load Serving Entities (LSEs), LSEs include IOUs, SMJUs, CCAs, and ESPs.[17] Moreover, the Commission also reviewed RPS contracts executed by the IOUs between 2003 and 2017 to show historic contract cost trends.[18] Figure 3 below shows that RPS contract prices, in real dollars, consistently dropped between 2007 and 2018 for the all technologies group. The annual contract price for all technologies decreased an average of 11.5% during that time. The downward trend in contract prices can be attributed to falling prices for wind and solar technologies, which together make up 83.2% of the large IOUs' collective RPS generating capacity. Contracts with a nameplate capacity of less than 3 MW and those reported as net cost instead of total contract price were not included in Figure 3 to remove non-representational trends.[19]

Figure 3: Historical Trend of RPS Contract Costs by Technology and Year of Execution from 2003-2020 (Real Dollars)



CPUC Report on RPS Costs and Cost Savings, May 2019
Contract costs in Figure 3 are reported by year of contract execution.

[17] 2018 Contract price data for CCAs and ESPs was obtained through a data request stemming from the *Power Charge Indifference* Adjustment (PCIA) proceeding. 2003-2018 Contract data was reported by the IOUs through CPUC's RPS Executed Projects Database, which contains self-reported information by the IOUs on their RPS contracts.

[18] *See id.*

[19] Projects with a capacity of 3MW or less made up just 2.3% of all of the IOUs contracted RPS capacity, and removing these figures eliminated non-representative trends from the data. As a result of this size exclusion, feed-in-tariff projects were not considered in the analysis above. In California, feed-in-tariff programs provide projects with a capacity of 3 MW or less capacity a predetermined price ($/MWh) to encourage market transformation for projects at these sizes. Additionally, contracts identified as REC only payments were excluded as these values are not comparable to all in energy, capacity, and REC contract prices.

The average all technologies contract price spiked in 2016 as a result of mandated biomass procurement.[20]

In 2018, 19 unit specific/contingent contracts with nameplate capacities greater than 3 MW were signed by all LSEs. 15 contracts were signed by CCAs, 3 were signed by IOUs, and 1 was signed by an ESP. The average price of contracts executed in 2018 was 3.81 ¢/kWh compared to 4.70 ¢/kWh in 2017. Wind and solar accounted for 16 of the contracts executed in 2018 while biomass and small hydro accounted for just 3 contracts collectively. Following the historical trend shown in Figure 3, contract prices for RPS resources are anticipated to decline further. [21]

Bioenergy Market Adjusting Tariff Contracts

BioMAT is a Feed-in-Tariff program that uses a standard contract and a market-based mechanism to arrive at the offered program contract price, which deviates slightly from the solicitation process for contracts included in Figure 3. The goal of the BioMAT program is to promote a competitive market using a simple procurement mechanism for entrants to the bioenergy market. BioMAT allocates procurement to the distinct bioenergy areas of Biogas, Agriculture, and Sustainable Forest Management. Table 1 shows the weighted average BioMAT contract price and capacity procured in 2018 by the three IOUs. These values are not included in Figure 3, as they have a nameplate capacity of 3MW or less.

Table 1: Large Investor-Owned Utilities' 2018 BioMAT Procurement Summary

BioMAT Category	Procured Capacity (MW)	¢/kWh
Biogas	5.4	12.8
Dairy/Agriculture	8.3	18.8
Sustainable Forest Management	7.9	20.0

[20] High Hazard Zone (HHZ) biomass contracts were signed as a part of the state's response to Governor Brown's October 30, 2015, Emergency Proclamation and SB 859 (2016) to protect public safety and property from dead or dying trees and wildfires. Governor Edmund G. Brown Jr., *Proclamation of a State of Emergency* (October 30, 2015) https://www.gov.ca.gov/wp-content/uploads/2017/09/10.30.15_Tree_Mortality_State_of_Emergency.pdf.

[21] See also Lazard, Levelized Cost of Energy Analysis – Version 12.0 (November 2018) at 3, 7 (The levelized price for solar dropped 25%-18% in the last three years to subsidized prices in 2018 of $32-$44/MWh and wind dropped 9%-10% in the last three years to subsidized prices of $14-$47/MWh; subsidy analysis includes U.S. federal tax incentives and other monetary benefits resulting from the Tax Cuts and Jobs Act of 2017).

III. Comparison of RPS Procurement Expenditures to IOU Revenue Requirements

Large Investor-Owned Utilities

Table 2 compares RPS procurement expenditures to revenue requirements for the large IOUs. Specifically, the table shows the percentage of RPS procurement compared to total procurement for these IOUs' generation portfolios, as well as the RPS procurement costs as a portion of total revenue requirement. Additionally, Table 2 shows the large IOUs' RPS generation percentages for 2018.

Table 2 also shows that in 2018, RPS procurement expenditures were less than 20% of the IOUs' total revenue requirements. Compared to the total generation revenue requirements, the RPS expenditures make up a much smaller portion of the total revenue requirements, since total revenue requirements contain many large line items such as transmission expenditures, reliability costs, administrative, and capital expenses.

Table 2: Comparison of Large Investor-Owned Utilities' RPS Procurement to Revenue Requirements in 2018[22] [23]

Investor-Owned Utility	RPS Generation	RPS Procurement Expenditures (billions)	Total Generation Revenue Requirement (billions)	RPS Procurement Expenditures to Total Generation Revenue Requirement (%)	Total Revenue Requirement (billions)	RPS Procurement Expenditures to Total Revenue Requirement (%)
PG&E	37.7%	$2.4	$5.6	44%	$13.7	17.9%
SCE	37.1%	$2.5	$5.9	42%	$12.2	20.2%
SDG&E	46.3%	$0.68	$1.9	37%	$4.3	15.8%

On a kilowatt-hour (kWh) basis, RPS expenditures are largely in-line with non-RPS expenditures. As the large IOUs are required to procure higher percentages of RPS-eligible energy, they are procuring less non-RPS-eligible energy for their electric portfolios. Given that RPS energy is replacing fossil fuel energy, an increase in the revenue requirement due to RPS procurement, while difficult to calculate, can be approximated by comparing the average cost of RPS energy to non-RPS energy. The large IOUs' average cost of renewable energy was 10.6 ¢/kWh and the average cost of non-RPS energy was 9.0 ¢/kWh. Therefore, the RPS program on average likely contributed approximately 1.6 ¢/kWh procured to obtain program benefits.[24]

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22 Revenue requirement numbers have been taken from the CPUC's "California Electric and Gas Utility Cost Report" Pursuant to Public Utilities Code § 913, May 2019.

23 RPS generation percentages are forecasts taken from the LSEs' 2018 RPS Compliance Reports and procurement data collected from individual IOUs.

24 The RPS cost premium compared to non-RPS energy on a kilowatt-hour basis is represented by the following equation: *10.6 ¢/kWh (RPS) - 9.0 ¢/kWh (Non-RPS Energy) = 1.6 ¢/kWh.* The additional 1.6 cents added to revenue requirements per kWh due to RPS procurement does not significantly impact the average household bill. This is because generation costs comprise roughly half of the total bill, and RPS costs are roughly half of the total generation costs. See the CPUC's 2019 AB 67 Report for more information on electric rates.

Small and Multi-Jurisdictional Investor-Owned Utilities

2018 revenue requirement information for Liberty, BVES, and PacifiCorp is currently confidential pursuant to Commission confidentiality rules.[25] Consequently, the CPUC is not able to perform an analysis on SMJU costs compared to their revenue requirements for 2018. However, Table 3 provides a summary of Liberty's, PacifiCorp's, and BVES' total 2018 RPS procurement expenditures.

Table 3: Comparison of Small and Multi-Jurisdictional Investor-Owned Utilities' Total RPS Expenditures in 2018

	Liberty	PacifiCorp	Bear Valley Electric Service
Total	$5,526,861	$4,853,243	$369,666

[25] See D.06-06-066 for confidentiality rules related to revenue requirements.

RENEWABLES PROGRAM COST SAVINGS

This section addresses the cost savings associated with procuring renewable resources in 2018, consistent with the requirements of § 913.3(c).

> **Section 913.3(c)**
> The commission shall report all cost savings experienced, or costs avoided, by electrical corporations as a result of meeting the renewables portfolio standard.

It is difficult to quantify the cost savings, or avoided costs, associated with the RPS program given this requires assessing whether the RPS program deferred construction of alternative generation facilities and the theoretical cost of those alternative resources. The Commission also cannot estimate the impacts that increased renewables and the resulting fuel diversity have had on the cost of natural gas in California. To assess the RPS program's cost savings, this report compares the utilities' 2018 RPS procurement costs to benchmark values produced by the market price referent (MPR) methodology and the utilities' 2018 non-RPS eligible procurement costs.

There is no perfect counterfactual to assess the RPS program's cost savings. The MPR is a limited model that is based on a proxy baseload generation facility, and its inputs include forward natural gas prices and greenhouse gas (GHG) allowance prices. Also, the non-RPS resource costs, such as Resource Adequacy contract prices, are based on the preexisting supply of facilities and capacity need that are not tethered to the same market considerations as RPS contracts. As discussed above, the variables that inform these benchmarks are imperfect because they are not narrowly tailored to capture the benefits and costs of the RPS program.

I. The Market Price Referent (MPR) Methodology

The MPR was developed for the Commission to determine whether a competitively bid RPS contract had above-market costs. The MPR models the cost to build and operate a baseload combined-cycle gas turbine (CCGT) power plant in a desired year, and the MPR model generates a benchmark price.[26] The model was adopted by the Commission as a proxy for the "levelized price of a utility's long-term [power purchase agreement (PPA)] with a new natural-gas fueled generation facility in California."[27] While no longer used in RPS contract review, the Commission still finds the MPR is the best method for comparing and determining cost savings for the RPS program, because it is a publicly vetted proxy for the cost of a new power plant and it provides consistency with prior Padilla reports. However, since the last Commission-approved MPR model was updated in 2011 (2011 MPR), certain inputs no longer reflect current market conditions. Therefore, three inputs of the 2011 MPR model have been updated for this report (updated 2018 MPR). For the updated 2018 MPR, natural gas burner tip price forecasts were taken from the California Energy Commission's updated 2019 Integrated Energy Policy Report (IEPR),[28] the emission rate of carbon dioxide for each MWh of CCGT generation was taken from the 2018 Avoided Cost Calculator (ACC),[29] and GHG planning prices were taken from the IRP proceeding.[30]

Table 4: Comparison of MPR Benchmarks (¢/kWh)

Method	Proxy Costs
2011 MPR	11.1
Updated 2018 MPR	8.5

<u>Large Investor-Owned Utility Cost Savings</u>

The average 2018 RPS procurement expenditures for PG&E, SCE, and SDG&E were 12.2 ¢/kWh, 9.6 ¢/kWh, and 9.5 ¢/kWh, respectively.[31] The average RPS procurement expenditure for the large IOUs was 10.6 ¢/kWh.[32] Compared to the 2011 MPR proxy cost of 11.1 ¢/kWh, the large IOUs realized a cost savings of 0.5 ¢ for each kWh of RPS energy. Compared to the updated 2018 MPR proxy cost of 8.5 ¢/kWh, the large IOUs paid a premium of 2.1¢ for each kWh of RPS energy. Differences in costs between the 2011 MPR and the Updated 2018 MPR is largely caused by lower forecasted natural gas prices in the 2018 model.

[26] See D.08-10-026.
[27] *Id.* at 1.
[28] California Energy Commission staff methodology and calculations, using the Preliminary Mid-Demand Case natural gas price and demand results for the California power generation sector from the 2019 Integrated Energy Policy Report — Natural Gas Market Trends and Outlook, plus the Power Plant Burner Tip Model topology, and the natural gas utilities' transportation rates from their tariffs filed with FERC or the CPUC, as applicable.
[29] The Avoided Cost Calculator can be found on the CPUC's Cost Effectiveness website: http://www.cpuc.ca.gov/General.aspx?id=5267.
[30] D.18-02-018 at 116. GHG planning prices for 2016 and 2017 were taken from the IRP's RESOLVE model. IRP GHG planning prices were selected to update the MPR as that value will be used to assess RPS projects, whereas the Integrated Distributed Energy Resources (IDER) figures were developed for distributed energy resources. *See* D.17-08-022 at 1, 13.
[31] Appendix B, Table B-1.
[32] *Id.*

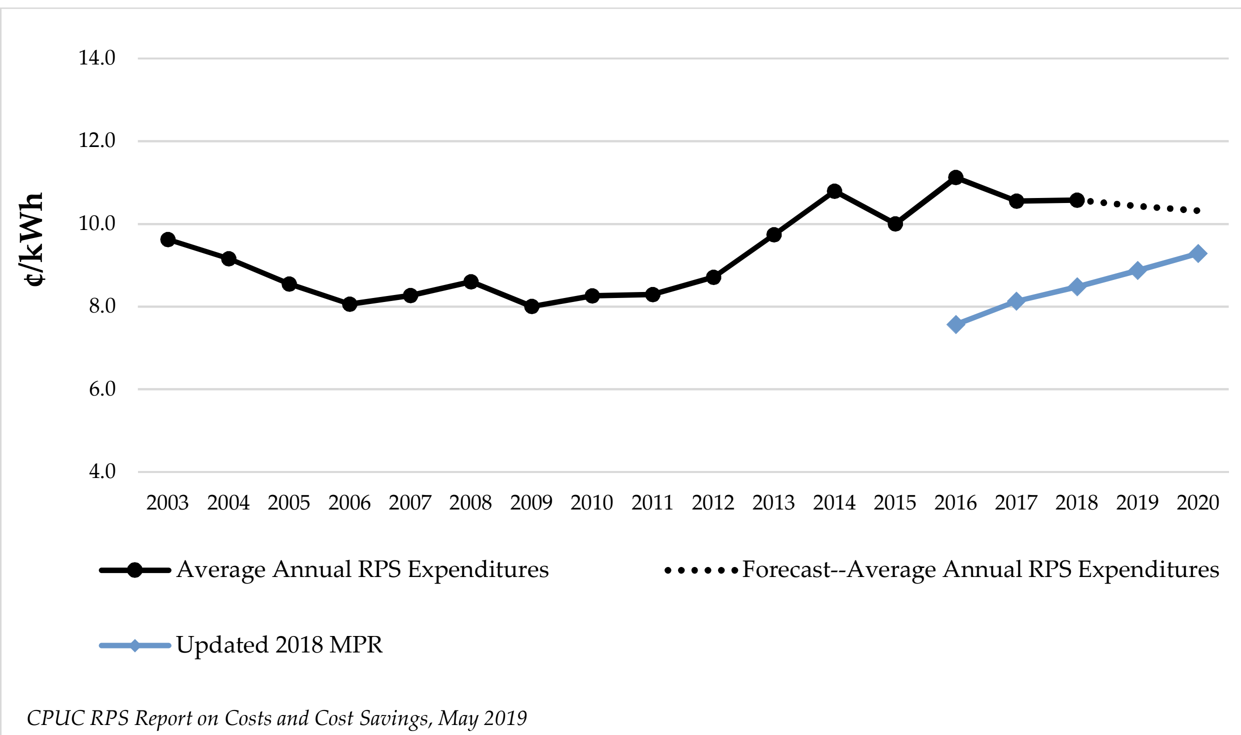
Based on total volumes of RPS generation procured and the different cost comparison metrics described above, the large IOUs realized the following cost savings (positive figures) or premiums (negative figures):

Table 5: Large Investor-Owned Utilities' 2018 RPS Cost Savings: MPR Methodology (millions)[33]

	Cost Savings Compared to 2011 MPR Proxy Expenditure	Cost Savings Compared to 2018 MPR Proxy Expenditure
PG&E	-$227	-$750
SCE	$394	-$282
SDG&E	$114	-$74
Cost savings are displayed as positive figures while cost premiums are displayed as negative figures.		

In 2018, the large IOUs' average annual RPS procurement expenditure was less than the benchmark created by the 2011 MPR and greater than the benchmark created by the updated 2018 MPR. However, the large IOUs' annual expenditures are not expected to remain above the updated benchmark in the long-term, because total RPS procurement expenditures are projected to decline on a per kWh basis as new, low-cost RPS projects come online. In 2018, the large IOUs' average annual RPS procurement costs increased slightly from 10.1 ¢/kWh in 2017 to 10.6 ¢/kWh in 2018. However, expenditures are forecasted to decline and MPR proxy prices will continue to go up over time as the models reflect increasing GHG planning prices.

Figure 4: Historic Trends and Projections for RPS Program Costs (Real Dollars)



[33] Cost savings or premiums are calculated by multiplying an MPR proxy price by an IOU's total volume of RPS procurement in 2018, then subtracting that value from the IOU's 2018 RPS Procurement Expenditures (shown in Table 2).

Small and Multi-Jurisdictional Investor-Owned Utilities Cost Savings

For the SMJUs, the average 2018 RPS procurement expenditure for Liberty was 3.6 ¢/kWh, PacifiCorp was 3.4 ¢/kWh, and BVES was 0.9 ¢/kWh.[34] Based on total volumes of RPS generation procured and the different cost comparison metrics described above, the SMJUs realized the following cost savings (positive figures) or premiums (negative figures):

Table 6: Small and Multi-Jurisdictional Investor-Owned Utilities' 2018 RPS Cost Savings: MPR Methodology (millions)[35]

	Cost Savings Compared to 2011 MPR Proxy Expenditure	Cost Savings Compared to 2018 MPR Proxy Expenditure
Liberty	$11.1	$7.4
PacifiCorp	$10.8	$7.1
Bear Valley Electric Service[36]	NA	NA
Cost savings are displayed as positive figures while cost premiums are displayed as negative figures.		

[34] *Supra*, note 15.
[35] Cost savings or premiums are calculated by multiplying an MPR proxy price with an SMJU's total volume of RPS procurement in 2018 then subtracting that value from the SMJU's 2018 RPS Procurement Expenditures (shown in Table 3).
[36] BVES's RPS projects consisted solely of REC-only products and is therefore not comparable to the MPR, as the MPR is a proxy cost for obtaining other energy and capacity benefits.

II. Non-RPS Eligible Procurement Methodology

In addition to the 2011 MPR and Updated 2018 MPR, the Commission considered the large IOUs' 2018 non-RPS eligible procurement expenditures as a cost comparison metric for the RPS program. The 2018 non-RPS procurement data is an appropriate cost comparison metric because in the absence of RPS procurement, non-RPS resources would be procured. Additionally, the non-RPS procurement expenditures below confirm the reasonableness of the MPR models.

Large Investor-Owned Utilities Cost Savings

In 2018, the large IOUs' average annual RPS procurement expenditure represented a 1.6 ¢/kWh premium compared to their average non-RPS procurement expenditure.[37] More specifically, PG&E and SCE paid a premium for RPS energy—compared to non-RPS energy—of 1.0 ¢/kWh and 2.6 ¢/kWh, respectively. On the other hand, SDG&E experienced a cost savings of 3.1 ¢/kWh. The variance in non-RPS eligible expenditures is likely related to high local-area Resource Adequacy costs in SDG&E's service area and the California Independent System Operator (CAISO) mandated reliability procurement in PG&E's service territory.[38] RPS resources provide a stable hedge against the volatile traditional resource costs as their long-term contracts provide consistent expenditures year-to-year.

Table 7: Large Investor-Owned Utilities' Average Non-RPS Eligible Procurement Expenditure (¢/kWh)

Method	PG&E	SCE	SDG&E	Average
2018 Non-RPS	11.2	7.0	12.6	9.0
2018 RPS	12.2	9.6	9.5	10.6

Based on total volumes of RPS and non-RPS eligible procurement expenditures, the large IOUs realized the following cost savings (positive figures) or premiums (negative figures):

Table 8: Large Investor-Owned Utilities' 2018 RPS Cost Savings: Non-RPS Eligible Comparison (millions)[39]

	Cost Savings Compared to 2018 Average Non-RPS Expenditure
PG&E	-$203
SCE	-$671
SDG&E	$222
Cost savings are displayed as positive figures while cost premiums are displayed as negative figures.	

[37] *Supra*, note 24.
[38] CPUC, *The 2017 Resource Adequacy Report* at 28, 33 (August 2018).
[39] Cost savings or premiums are calculated by multiplying each IOU's average 2018 non-RPS eligible expenditure (Table 7) by its total volume of RPS procurement in 2018 then subtracting that value from the IOUs' 2018 RPS procurement expenditure (Table 2).

Small and Multi-Jurisdictional Investor-Owned Utilities

In 2018, the RPS procurement expenditure for SMJUs represented a 1.4 ¢/kWh cost savings compared to their average non-RPS-eligible expenditure. The cost savings for RPS energy compared to non-RPS energy for Liberty and PacifiCorp was 1.1 ¢/kWh and 3.3 ¢/kWh, respectively. BVES' cost savings cannot be calculated; however, because BVES's RPS projects consisted solely of REC-only products. BVES RPS expenditures are therefore not comparable to their non-RPS expenditures, which include additional costs for obtaining energy and capacity benefits.

Table 9: Small and Multi-Jurisdictional Investor-Owned Utilities' Average Non-RPS Eligible Procurement Expenditure (¢/kWh)

Method	Liberty	PacifiCorp	Bear Valley Electric Service	Average
2018 Non-RPS	4.7	6.1	7.6	5.8
2018 RPS	3.6	3.4	0.9	3.2

Based on total volumes of RPS generation procured and non-RPS eligible procurement expenditures, the large SMJUs realized the following cost savings (positive figures) or premiums (negative figures):

Table 10: SMJU's 2018 RPS Cost Savings: Non-RPS Eligible Comparison (millions)[40]

	Cost Savings Compared to 2018 Average Non-RPS Expenditure
Liberty	$1.7
PacifiCorp	$3.8
Bear Valley Electric Service	NA
Cost savings are displayed as positive figures while cost premiums are displayed as negative figures.	

[40] Cost savings or premiums are calculated by multiplying each SMJU's average 2018 non-RPS eligible expenditure (Table 9) by its total volume of RPS procurement in 2018 then subtracting that value from the SMJUs' 2018 RPS procurement expenditure (Table 3).

APPENDICES

I. Appendix A: California Public Utilities Commission RPS Activities and Milestones

California Public Utilities Commission RPS Activities and Milestones in 2018	
January	• PG&E executed eight Bioenergy Feed-in Tariff Program or the Bioenergy Market Adjusting Tariff (BioMAT) contracts for a total capacity of 6.5 MW • SCE executed two BioMAT contracts for a total capacity of 1.6 MW
February	• PG&E issued solicitations to sell short-term and long-term RECs
March	• SCE submitted an application for termination of geothermal contracts • CPUC adopts Resolution E-4922 ordering the IOUs to continue the BioMAT program and to execute certain bioenergy contracts
April	• SDG&E issued a solicitation to sell short-term and long-term RECs • SCE executed three BioMAT contracts for a total capacity of 5.2 MW
May	• CPUC adopts D.18-05-026 implementing SB 350 (de León, 2015) provision on penalties and waivers in the RPS Program • CPUC adopts D.18-05-032 modifying BioMAT standard contracts • SCE executed BioMAT contract for a total capacity of 0.8 MW
June	• CPUC issued RPS Procurement Plan Assigned Commissioner/Administrative Law Judge Ruling providing guidance for 2018 RPS Procurement Plans • CPUC approved PG&E's request to sell 5,379 GWh RPS-eligible energy • PG&E executed ten BioMAT contracts for a total capacity of 14.3 MW
July	• CPUC issues new Rulemaking (R.18-07-003) for the RPS program • IOUs, CCAs, and ESPs submitted their draft RPS Procurement Plans to the CPUC • PG&E contracted a 75 MW solar PV project
August	• IOUs, CCAs, and ESPs submitted their annual preliminary RPS Compliance Reports to Energy Division
September	• PG&E issued a solicitation to sell short-term RECs
October	• CPUC issued ruling requesting comment on staff proposal related to three components of the least-cost best-fit (LCBF) RPS contract valuation methodology
November	• CPUC issues Annual RPS Report to the Legislature: http://www.cpuc.ca.gov/RPS_Reports_Data/ • Energy Division issues Draft BioMAT Program Review and Staff Proposal • PG&E executed BioMAT contract for a total capacity of 2.0 MW • CPUC adopts D.18-11-036 approving SCE's early termination of two geothermal power (Coso) purchase agreements
December	• CPUC adopts D.18-11-004 implementing interconnection rules for BioMAT • CPUC issues Scoping Memo for R.18-07-003 to continue implementation of the RPS program • CPUC adopts D.18-12-003 establishing a non-bypassable charge for costs associated with tree mortality biomass energy procurement • CPUC issues Draft Resolution amending BioRAM contracts consistent with SB 901

II. Appendix B: RPS Procurement Expenditures per Senate Bill 836 (Public Utilities Code § 913.3)

Overview of Tables

Table B-1 and B-2 show, for each large IOU, the weighted average time-of-delivery (TOD) adjusted RPS procurement expenditures for 2018. Per the confidentiality requirements in Public Utilities Code § 913.3, some of the data within this report is redacted in order to protect market sensitive information.

In addition:

- The "Average RPS Procurement Expenditures" represent the total weighted average payments made to renewable generators for 2018.
- Procurement expenditures represent weighted averages by capacity procured on a per kilowatt-hour basis. All figures are in 2018 dollars.

Table B-1. Weighted Average RPS Procurement Expenditures
(All Projects – Including REC-only transactions) for 2018 (¢/kWh)

	PG&E	SCE	SDG&E	Total
Biogas				
0-3 MW	14.40	8.69	10.54	11.66
+3-20 MW	11.91	6.72	7.37	10.45
Biogas Total	**12.45**	**7.84**	**8.86**	**10.85**
Biomass				
+3-20 MW	11.00	Only 1 Contract		11.11
+20-50 MW	11.70	9.91	Only 1 Contract	11.21
+50-200 MW	9.00			9.00
Biomass Total	**11.15**	**10.27**	**Only 1 Contract**	**10.90**
Geothermal				
+3-20 MW	9.00	6.32		7.54
+20-50 MW		6.37		6.37
+50-200 MW		8.75		8.75
+200 MW	8.00	8.79		8.45
Geothermal Total	**8.06**	**7.80**	**0.00**	**7.87**
Small Hydro				
0-3 MW	8.17	8.46	13.11	8.28
+3-20 MW	7.67	8.32		7.83
+20-50 MW	7.74			7.74
Small Hydro Total	**7.80**	**8.38**	**13.11**	**7.87**
Solar Photovoltaic				
0-3 MW	12.48	12.85	12.00	12.73
+3-20 MW	9.81	8.04	8.29	8.77
+20-50 MW	15.37	11.33	13.90	14.56
+50-200 MW	13.60	7.57	11.88	11.12
+200 MW	15.46	12.48		13.89
Solar Photovoltaic Total	**13.82**	**10.45**	**11.74**	**11.96**
Solar Thermal				
+20-50 MW		10.41		10.41
+50-200 MW	16.00	15.50		15.74
+200 MW	20.01			20.01
Solar Thermal Total	**18.82**	**14.11**	**0.00**	**17.35**
Wind				
0-3 MW	4.00	7.69		7.69
+3-20 MW	6.33	5.43	7.50	6.15
+20-50 MW	9.61	7.74	5.13	7.33
+50-200 MW	8.14	9.53	6.25	8.44
+200 MW		8.70	10.49	8.99
Wind Total	**8.10**	**9.09**	**6.96**	**8.43**
UOG Small Hydro				
0-3 MW	75.52	9.15		40.83
+3-20 MW	19.81	8.42		17.03
+20-50 MW	29.59	3.55		12.99
UOG Small Hydro Total	**23.97**	**6.50**	**0.00**	**17.80**
UOG Solar Photovoltaic				
0-3 MW	33.71	69.75	57.66	64.92
+3-20 MW	21.26	62.32	24.74	35.55
+20-50 MW	19.42			19.42
UOG Solar Photovoltaic Total	**20.20**	**64.98**	**32.80**	**29.98**
Average of All Resources	**12.24**	**9.57**	**9.52**	**10.57**

Table B-2. Weighted Average RPS Procurement Expenditures (Bundled Energy Only) for 2018 (¢/kWh)

	PG&E	SCE	SDG&E	Total
Biogas				
0-3 MW	14.40	8.69	10.54	11.66
+3-20 MW	11.91	6.72	7.37	10.45
Biogas Total	**12.45**	**7.84**	**8.86**	**10.85**
Biomass				
+3-20 MW	11.00	Only 1 Contract		11.11
+20-50 MW	11.70	9.91	Only 1 Contract	11.21
+50-200 MW	9.00			9.00
Biomass Total	**11.15**	**10.27**	**Only 1 Contract**	**10.90**
Geothermal				
+3-20 MW	9.00	6.32		7.54
+20-50 MW		6.37		6.37
+50-200 MW		8.75		8.75
+200 MW	8.00	8.79		8.45
Geothermal Total	**8.06**	**7.80**	**0.00**	**7.87**
Small Hydro				
0-3 MW	8.17	8.46	13.11	8.28
+3-20 MW	7.67	8.32		7.83
+20-50 MW	7.74			7.74
Small Hydro Total	**7.80**	**8.38**	**13.11**	**7.87**
Solar Photovoltaic				
0-3 MW	12.48	12.85	12.00	12.73
+3-20 MW	9.81	8.04	8.29	8.77
+20-50 MW	15.37	11.33	13.90	14.56
+50-200 MW	13.60	7.57	11.88	11.12
+200 MW	15.46	12.48		13.89
Solar Photovoltaic Total	**13.82**	**10.45**	**11.74**	**11.96**
Solar Thermal				
+20-50 MW		10.41		10.41
+50-200 MW	16.00	15.50		15.74
+200 MW	20.01			20.01
Solar Thermal Total	**18.82**	**14.11**	**0.00**	**17.35**
Wind				
0-3 MW	4.00	7.69		7.69
+3-20 MW	6.33	5.43	7.50	6.15
+20-50 MW	9.61	7.74	5.13	7.33
+50-200 MW	8.14	9.53	7.29	8.69
+200 MW		8.70	10.49	8.99
Wind Total	**8.10**	**9.09**	**7.79**	**8.61**
UOG Small Hydro				
0-3 MW	75.52	9.15		40.83
+3-20 MW	19.81	8.42		17.03
+20-50 MW	29.59	3.55		12.99
UOG Small Hydro Total	**23.97**	**6.50**	**0.00**	**17.80**
UOG Solar Photovoltaic				
0-3 MW	33.71	69.75	57.66	64.92
+3-20 MW	21.26	62.32	24.74	35.55
+20-50 MW	19.42			19.42
UOG Solar Photovoltaic Total	**20.20**	**64.98**	**32.80**	**29.98**
Average of All Resources	**12.24**	**9.57**	**10.05**	**10.65**

III. Appendix C: Contract Price Data per Senate Bill 836 (Public Utilities Code § 913.3)

Overview of Contract Price Data

Table C-1 shows the weighted average time-of-delivery (TOD) adjusted contract price for all of the large IOUs' RPS contracts approved by the CPUC in 2018. Per the confidentiality requirements in Public Utilities Code § 913.3, some of the data within this appendix could be redacted:

- Contract prices were to be redacted if a) the power purchase agreement (PPA) is not already public on the CPUC's website per the CPUC's confidentiality rules, and b) there were fewer than three facilities in each category. If there was only one facility in a category and its PPA is publicly available on the CPUC's website, then the price information for that facility is reported. In addition, the following contracts are public and reported: all qualifying facility (QF) contracts that do not require CPUC approval, feed-in tariff contracts, contracts with municipal governments, affiliate entities, and utility-owned generation (UOG) costs.
- Weighted average contract prices represent contract prices weighted by capacity procured on a per kilowatt-hour basis. All figures are in 2018 dollars.
- All contract price figures have been adjusted by TOD factors since generators are paid based on the time that the facility delivers electricity, according to each IOU's TOD factors. For example, IOU TOD factors place a premium on generation that occurs during peak demand hours. Therefore, generators that provide electricity during peak hours when electricity is more valuable receive a higher payment for electricity during that time period based on the TOD adjustment.

Table C-1. Weighted Average TOD-Adjusted Price of All Renewable Energy Contracts Approved for 2018 (¢/kWh)

	PG&E	SCE	SDG&E	Total
Biogas				
0-3 MW	20.23	13.52		17.30
Biogas Total	**20.23**	**13.52**	**0.00**	**17.30**
Biomass				
0-3 MW	19.17			19.17
Biomass Total	**19.17**	**0.00**	**0.00**	**19.17**
Solar Photovoltaic				
0-3 MW		Only 1 Contract		Only 1 Contract
+50-200 MW	Only 1 Contract	Only 1 Contract		Only 2 Contracts
Solar Photovoltaic Total	**Only 1 Contract**	**Only 2 Contracts**	**0.00**	**3.71**
Weighted Average of All Resources	**6.79**	**5.95**	**3.60**	**6.24**

IV. Appendix D: Public Utilities Code § 913.3(a)–(d)

Text of Public Utilities Code § 913.3(a)–(d)

913.3. (a) Notwithstanding subdivision (g) of § 454.5 and § 583, no later than May 1 of each year, the commission shall release to the Legislature for the preceding calendar year the costs of all electricity procurement contracts for eligible renewable energy resources, including unbundled renewable energy credits, and all costs for utility-owned generation approved by the commission.

(1) For power purchase contracts, the commission shall release costs in an aggregated form categorized according to the year the procurement transaction was approved by the commission, the eligible renewable energy resource type, including bundled renewable energy credits, the average executed contract price, and average actual recorded costs for each kilowatt-hour of production. Within each renewable energy resource type, the commission shall provide aggregated costs for different project size thresholds.

(2) For each utility-owned renewable generation project, the commission shall release the costs forecast by the electrical corporation at the time of initial approval and the actual recorded costs for each kilowatt-hour of production during the preceding calendar year.

(b) The commission shall report all electrical corporation revenue requirement increases associated with meeting the renewables portfolio standard, as defined in § 399.12, including direct procurement costs for eligible renewable energy resources and renewable energy credits.

(c) The commission shall report all cost savings experienced, or costs avoided, by electrical corporations as a result of meeting the renewables portfolio standard.

(d) This section does not require the release of the terms of any individual electricity procurement contracts for eligible renewable energy resources, including unbundled renewable energy credits, approved by the commission. The commission shall aggregate data to the extent required to ensure protection of the confidentiality of individual contract costs even if this aggregation requires grouping contracts of different energy resource type. The commission shall not be required to release the data in any year when there are fewer than three contracts approved.